Navigant Consulting, Inc.

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Appendix I

LCP Portfolio Screening

Assumptions, Methodology, & Results

March, 2003

PSE Puget Sound Energy

Summary of Portfolios Constructed and Analysis Summary

	Status Quo	Level A1	Level A2	Level B1	Level B2	Level C1	Level C2	Deferral (Level B1)	Joint Ownership	Forward Capacity Sales	System Exchange
All Gas	X	X	X	X	X	X	X	X	X	X	X
All Coal		X		X		X		X			
All Wind		X		X		X		X			
Gas & Coal	X	X	X	X	X	X	X	X	X	X	X
5% Wind $ Gas & Coal Mix	X	X	X	X	X	X	X	X	X	X	X
2% Wind & Gas		X		X		X		X	X		
5% Wind & Gas		X		X		X		X	X		
10%Wind & Gas		X		X		X		X	X		
10%Wind & Gas & Coal	X	X	X	X	X	X	X	X	X	X	X

Analysis Summary Continued

Porffolio Mix	Aurora Case 1		Aurora Case 2		Aurora Case 3	
	Static	Volatility	Static	Volatility	Static	Volatility
All Gas	X	X	X		X	X
All Coal	X	X	X		X	
All Wind	X	X	X		X	
Gas & Coal	X	X	X		X	X
5% Wind Gas & Coal	X		X		X	X
10% Wind Gas & Coal	X		X		X	X
2% Wind & Gas	X	X	X		X	
5% Wind & Gas	X	X	X		X	
10% Wind & Gas	X	X	X		X	

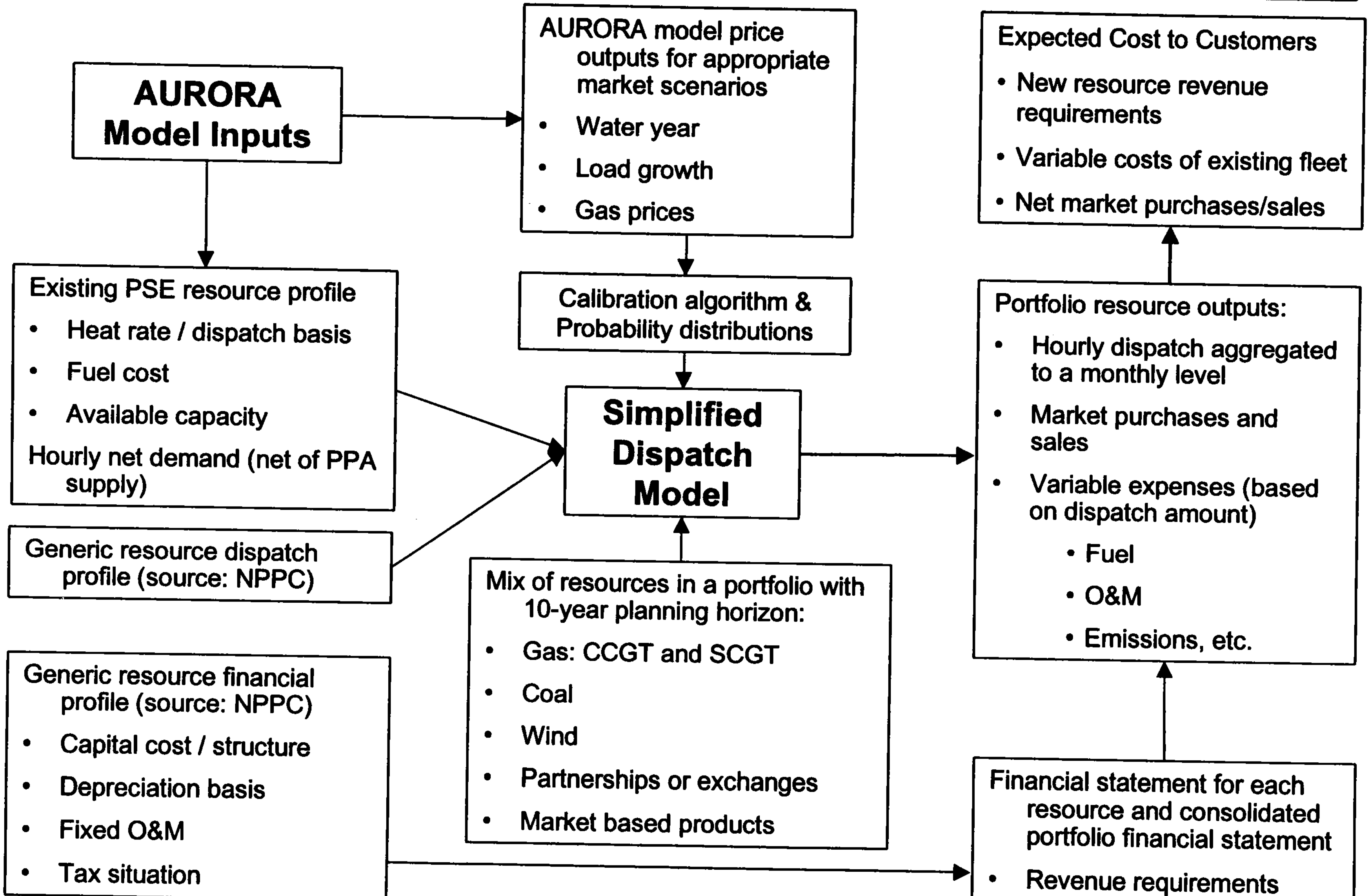
LCP Portfolio Screening Tool - Overview

The Portfolio Screening Tool is composed of two main parts:

- Dispatch Model Calculation
  - Dispatches PSE fleet and potential new resources against hourly power prices from AURORA for WA/OR region
  - Utilizes the same inputs to AURORA for plant profiles and demand
  - Uses Crystal Ball Monte Carlo simulation to achieve probability weighted results
  - Output from dispatch model includes MWh for the PSE fleet and an assumed portfolio of new resources and their associated variable (or incremental) costs (fuel, O&M, etc.)

- Financial Summary and Expected Cost to Customer Calculation
  - MWhs produced and variable cost data from the dispatch model is used in conjunction with fixed cost assumptions to derive a 'bottom up' revenue requirement for each new resource being considered
  - A financial summary is generated for each new resource technology that includes an income statement, cash flow summary and an approximation of regulatory asset base
  - Financial data from each new resource are then consolidated
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

LCP Screening Tool Modeling Process Flow Chart



Net Demand Development

- Monthly demand and resource summaries extracted from AURORA for the forecast period (see 2003 example below) are used to develop Net Demand

Energy (aMW)	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Hydro	2003	1,106	906	993	1,022	1,114	1,116	1,026	852	536	652	732	800	905
Colstrip	2003	598	598	598	432	598	464	598	598	598	598	598	598	573
Encogen & CTs	2003	99	61	82	79	48	59	143	339	320	183	116	113	137
NUGs	2003	586	252	357	272	97	86	473	524	528	508	498	504	392
Contracts Purch/(Sale)	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Market Purchases	2003	96	419	291	251	135	193	14	18	197	232	301	498	219
Market Sales	2003	(135)	(8)	(71)	(79)	(70)	(52)	(348)	(291)	(141)	(52)	(53)	(22)	(111)
Total Demand	2003	2,853	2,705	2,548	2,224	2,071	2,001	1,977	2,084	2,071	2,330	2,555	2,879	2,357
Contracts	2003	504	478	299	247	149	136	72	44	33	210	363	390	242
Net Demand	2003	2,349	2,227	2,250	1,978	1,922	1,866	1,905	2,039	2,038	2,120	2,191	2,490	2,115

- The monthly Net Demand is derived by taking the total demand and subtracting contract purchases/(sales)
- The monthly Net Demand is converted to hourly Net Demand through the following process:
  - The 2003 hourly demand forecast is the basis for the load shape for all forecast years
  - An average demand is calculated for each month in 2003 and then a actual/average factor is calculated for each hour (demand in each hour in a month is divided by the monthly average)
  - These factors for each hour are then applied to the monthly Net Demand to create 8760 Net Demand profiles for each forecast period
  - The 2003 base year begins on Wed, the 2003 shape is applied to each forecast year beginning on the day the forecast year starts (e.g. Thursday in 2004, Saturday in 2005, etc.) (same as AURORA methodology)

Dispatchable Resources

- The dispatchable plants are:
  - PSE owned: Fredonia1&2, Fredonia 3&4, Frederickson 1&2, Whitehorn 2&3, Colstrip 1&2, Colstrip 3&4 and Encogen (dispatchable)
  - NUG's: March Point 1&2 (dispatchable), Sumas, and Tenaska
  - New resources: CCGT (including structured deals), SCGT, and coal
- There are two primary data inputs to the dispatch logic from the dispatchable plants:
  - Dispatch Basis: This is the marginal cost of dispatch and is sum of variable O&M, fuel cost (calculated by running a "burner tip" $/MMBtu fuel cost through the plants heat rate to arrive at $/MWh), and any other incremental costs (e.g. emissions, transmission, etc.)
  - Dispatchable Capacity: The dispatchable capacity adjusts the net capacity for an asset by a forced outage rate applied evenly over all periods, and a planned outage rate applied when the outage is expected

Plant	Net Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost (Note/$/MMBtu)	Planned Outage Period (Approx.)
Fredonia 1&2	202.1	11,569	16.87	2.12	Sumas + trans.	1 week in May
Fredonia 3&4	108.0	10,540	5.00	2.12	Sumas + trans.	1 week in May
Frederickson 1&2	141.0	12,450	14.26	2.12	Sumas + trans.	1 week in April
Whitehorn 2&3	134.4	11,987	13.23	2.12	Sumas + trans.	1 week in April
Colstrip 1&2	298.6	10,889	10.38	Inc. in fuel	0.45	2 weeks in May
Colstrip 3&4	359.9	10,695	8.29	Inc. in fuel	0.60	2 weeks in June
Encogen - Disp.	120.0	9,032	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - Disp.	0.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - Disp.	13.0	12,000	0.20	Inc. in fuel	Sumas	Inc. in FOR
Sumas	133.0	8,200	1.80	Inc. in fuel	Sumas	Inc. in FOR
Tenaska	245.0	8,700	0.30	Inc. in fuel	Sumas	Inc. in FOR
CCGT - Generic	NA	7,030	5.00	2.80	Sumas	1 week
SCGT - Generic	NA	9,960	3.60	8.00	Sumas	1 week
Coal - Generic	NA	9,550	7.00	1.75	0.73	2 weeks/yr

Source: 2002 Rate Case with some updates

Must Run and Renewable Resources

- The must run plants are:
  - PSE Owned: All hydro plants, and Encogen MR
  - NUG's: March Point 1&2 MR
  - New resources: Wind
- The Must Run plants have only have Dispatchable Capacity as input to the dispatch logic
  - The must run portions of Encogen and March Point calculate the Dispatchable Capacity in the same fashion as the dispatchable portions of those plants
  - The wind units have their nominal capacity adjusted for monthly availability based on seasonal variations in wind patterns (the proxy is currently for wind located in the Basin & Range region of OR and ID)
  - The hydro unit Dispatchable Capacity is based on the monthly availability for the average water year in the 40-year hydro data set from NWPP and the hourly dispatch shape for a 2003 base year in AURORA
    - ✓ The hourly shape adjusts the monthly average in a similar fashion as the Net Demand

Plant	Net Capacity (MW)	Heat Rate (Btu/KWh)	Forced Outage Rate (%)	VOM ($/MWh)	Fuel Cost (Note/$/MMBtu)	Planned Outage Period (Approx.)
Encogen - MR	51.0	9,830	1.97	Inc. in fuel	Sumas + trans.	Inc. in FOR
March Point 1 - MR	85.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
March Point 2 - MR	50.0	8,500	0.20	Inc. in fuel	Sumas	Inc. in FOR
Wind	NA	NA	72%	1.00	NA	NA

Source: 2002 Rate Case with some updates

Hydro Plants

Plant	Nominal Capacity (MW)	Monthly Availability Factor											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Upper Baker	104.9	28%	26%	21%	27%	47%	21%	57%	62%	13%	45%	65%	35%
Lower Baker	79.0	67%	52%	39%	55%	68%	43%	60%	79%	22%	66%	82%	74%
White River	62.5	69%	53%	46%	53%	65%	69%	45%	55%	6%	22%	64%	32%
Puget Small Plants	69.7	74%	76%	74%	82%	88%	87%	72%	53%	34%	41%	74%	77%
Wells	262.9	67%	54%	62%	65%	72%	73%	65%	53%	36%	36%	36%	45%
Rocky Beach	492.7	69%	56%	64%	67%	72%	78%	69%	55%	37%	38%	38%	47%
Rock Island 1	163.1	68%	69%	66%	65%	61%	61%	64%	66%	64%	64%	68%	65%
Wanapum	106.5	68%	55%	59%	46%	37%	45%	44%	32%	34%	35%	36%	46%
Priest Rapids	73.0	75%	63%	66%	41%	17%	33%	41%	32%	43%	44%	44%	55%
Rock Island 2	174.0	95%	65%	88%	92%	100%	100%	89%	57%	28%	31%	26%	52%

The hydro availability is based on the mean of the 40-year data set

Must Run and Renewable Resources Continued

Month	Basin & Range	Cascades & Inland	Northern California	Northwest coast	Rockies & Plains	Southern California
January	119%	103%	22%	119%	161%	68%
February	139%	90%	28%	157%	157%	66%
March	107%	107%	69%	107%	102%	97%
April	105%	107%	113%	86%	84%	128%
May	94%	121%	181%	84%	77%	175%
June	71%	107%	188%	84%	73%	133%
July	56%	111%	210%	101%	35%	147%
August	61%	107%	185%	54%	42%	95%
September	72%	94%	96%	66%	52%	87%
October	74%	73%	65%	80%	100%	82%
November	159%	85%	24%	140%	130%	65%
December	143%	96%	18%	121%	188%	57%
FOR	72%	70%	69%	70%	64%	69%

- PSE is currently using the Cascade & Inland profile in the calculations
  - Appears to be where the most promising near-term projects are

Emissions Assumptions

Emission rate (T/GWh)	SO2	NOX	CO2	Source
Fredonia 1&2	-	0.00002	582.00	PSE
Frederickson 1&2	0.00080	0.03900	582.00	NPPC Generic
Fredonia 3&4	0.00080	0.03900	582.00	PSE
Whitehorn 2&3	0.000003	0.00002	582.00	PSE
Colstrip 1&2	2.27613	2.09048	1,119.24	EPA
Colstrip 3&4	0.50220	2.19521	1,097.69	EPA
Encogen (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
March Point 1&2 (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
Sumas	0.00200	0.03900	411.00	NPPC Generic
Tenaska	0.00200	0.03900	411.00	NPPC Generic
CCGT	0.00200	0.03900	411.00	NPPC Generic
SCGT	0.00080	0.05523	582.00	NPPC Generic
Coal	0.38200	0.35000	1,012.00	NPPC Generic
Escalation	-	-	-	
Base Cost/Ton	200.00	-	-	

Equity Partnerships

- The equity partnership or Joint Ownership resource is characterized by entering into a transaction with a developer or other party for partial ownership of a generating resource asset and partial rights to output
  - The Screening Tool allows specification of which months PSE would claim rights to output from the facility
  - The capital cost of the facility (whether it is for completion of a project, construction of a new project or partial purchase of an existing facility) is split between the two parties on a market price weighted basis
    - ✓ The price weighted calculation ratios the average market prices of the respective output ownership rights
    - ✓ The price-weighted split of capital cost assumes both parties have the same view of market prices going forward and there is no discount or premium for either party

Dispatch Logic

- The hourly dispatch of the PSE fleet and the new resources considered in the planning portfolio is done on a month by month basis (this is due to size constraints within Excel)
- The dispatch logic is as follows:
  - For each hour, the Dispatch Basis for each dispatchable plant is compared to the market price for that hour, if the Dispatch Basis is less than the market price, then the plant generates its Dispatchable Capacity for that hour, else, it does not dispatch that hour
  - The total generation from the dispatchable plants is summed for each hour
  - The total generation from the must run plants is added to the total generation from the dispatchable plants
  - The grand total of plant generation (dispatchable and must run) is compared to the Net Demand for each hour, if the amount generated is less than the Net Demand, then that amount represents a market purchase, if the amount generated is greater than Net Demand, than that amount represents a market sale
  - For every hour where there is a market sale or purchase, the market price at that hour is used to calculate the financial impact of the purchase or sale
- The major simplification from the dispatch logic in AURORA is that there is no provision for unit minimum run times, ramp rates, minimum dispatch levels, etc.

End Effects Implementation in the Screening Model

- The issue of end effects arises because PSE has a 20-year evaluation period for assets with a 30-year life, this is compounded by the fact that PSE's portfolio planning horizon allows asset additions to occur through year 10, effectively creating a 40-year horizon for asset life
- To deal with years 21-40 in the analysis, PSE uses the following methodology:
  - Forecast the free cash flows (100% equity basis) from the assets for years 21 to 40
  - NPV the free cash flows to year 20 at the after-tax WACC
  - Compare the NPV at year 20 to the remaining book value at year 20
  - NPV the difference to year one at the after tax WACC
  - Subtract the year one value from the Total Cost to Customer
- The free cash flow are estimated using the following assumptions:
  - ***Revenue***: The revenue from year 17-20 is averaged and escalated at 2.5%
  - ***Fuel and VOM***: The fuel and VOM from year 17-20 is averaged and escalated at 2.5%
  - ***Capacity Factor***: The capacity factor from year 17-20 is averaged and held constant for year 21-40
  - ***FOM***: The FOM continues to be escalated as in years 1-20
  - ***Property Tax***: The property tax is trended down from year 17-20 (follows the trend down in rate base)
  - ***Insurance***: The insurance is trended down from year 17-20 (follows the trend down in rate base)
  - ***Depreciation***: The tax depreciation is run out normally for all assets past year 20
- The impact of the end effects are relatively small in comparison to the Total Cost to Customer, on the order of 2% of the total

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies*

- Dates used for analysis period
  - Planning horizon for resource acquisition is 10 years beginning Jan. 1, 2004
  - Model assumes 'financial close' date of 12/31/2003 as basis for the model starting point
  - Analysis period is 20 years

- Expense / Capital escalation rates
  - Both fixed and variable O&M currently assume a 2 ½% annual escalation factor
  - Both periodic and acquisition capex assume a 2 ½% annual escalation factor
    - ✓ Methodology – The model assumes two kinds of additional capex: 'incremental capex' and 'acquisition capex.' 'Incremental capex' are capital expenditures (plant) acquired on an annual basis using a $/Kwh valuation. The current model assumes that 'incremental capex' is funded through available cash rather than by debt. Alternatively, the model assumes that 'acquisition capex', or capital expenditures related to acquiring new generation MW during the 10-year planning horizon, are financed using the debt to equity ratio supplied by PSE (60% debt to 40% equity).

- Capital Costs (New Acquisition Capex in $/kw)

	All in Cost ($/kw)
CCGT	$645
SCGT	$441
Coal	$1,500
Wind	$1,003
Duct Fired	$150
Joint Ownership	$423

Financial Summary and Revenue Requirement Calculation - *Assumptions and Methodologies - continued*

- O&M Costs (Table below outlining Fixed rates in $/kw-yr and Variable O&M rates in $/MWh)

	CCGT	SCGT	Coal	Wind	Duct Fired	Joint Ownership
FOM ($/kw-yr)	$41.43	$18.74	$49.76	$40.98	$30.43	$27.14
VOM ($/MWh)	$2.00	$2.00	$2.00	$1.00	$2.00	$2.00
Fuel Basis Differential ($/MWh)	$3.45	$5.85	$0.00		$4.55	$3.45
Total VOM ($/MWh)	$5.45	$7.85	$2.00	$1.00	$6.55	$5.45

- Finance and Regulatory assumptions
  - Cost of equity and debt (used for both the WACC and debt amortization calculations) – 11.0% and 7.24% respectively
  - Pre / After Tax WACC – 8.95% and 7.61% respectively
  - Conversion Factor (gross-up factor used in revenue requirement calculation) – 62.02%
    - ✓ Roughly equivalent to (1- Federal tax rate and miscellaneous regulatory fees)

- Heat Rate and Forced Outage Rates

	CCGT	SCGT	Coal	Wind	Duct Fired	Joint Ownership
Heat Rates	6,900	11,700	9,425		9,100	6,900
Forced Outage Rates	5%	4%	7%	70%	0%	5%

Financial Summary and Revenue Requirement Calculation - *Calculation Detail*

The revenue requirement for a specified portfolio utilizes a 'bottom-up' approach where total fixed and variable costs are used to back solve for the appropriate revenue stream that would yield an operating income stream sufficient to provide a desired regulated rate of return. The following discussion outlines how individual components of fixed and variable expenses are calculated:

- Variable Costs – Fuel and Variable O&M
  - Fuel expense is calculated by multiplying the calculated number of MWh dispatched or generated each month, times the heat rate of the plant times the appropriate fuel curve (i.e. gas or coal)
  - Variable O&M is calculated by taking the appropriate VOM factor (as provided by PSE and illustrated on the previous slide), applying the VOM escalation percentage adjusted for time, and multiplying the resulting inflation adjusted VOM factor (in $/Kwh) times the number of Kwh produced for the selected technology
- Fixed Costs – Fixed O&M
  - The FOM Factor provided by PSE should includes all categories of fixed costs associated with the various technologies under consideration
  - The fixed cost calculation is similar to that of Variable O&M in that the FOM factor (quoted in $/Kw) provided by PSE is inflation-adjusted using the escalation factor illustrated on the previous slide and multiplied times the plant capacity (rather than the number of Kwh produced)
- Depreciation - Book and Tax
  - Book – Modeled value assumes 30- year recovery on all capital additions (Wind 25 years)
  - Tax – The portfolio model contains flexibility to select from 5, 10, 15 and 20 year MACRS (half-year convention)
    - ✓ The current test cases utilize 5-year MACRS for 'green' resources, 15-year MACRS for simple and combined cycle gas and 20-year MACRS for coal fired resources.

Financial Summary and Revenue Requirement Calculation - *Calculation Detail - continued*

- Debt Service – Interest
  - The interest is calculated as a function of Rate Base
  - The long-term capital structure assumes 52.57% debt
  - The interest rate is assumed to be 7.4%

- Tax – Current and Deferred
  - Current taxes are computed on taxable income calculated using tax depreciation rates previously discussed
  - Differences between book and tax depreciation are the only items considered to generate book/tax differences that give rise to deferred taxes
  - Currently, the model assumes a 37.98% effective marginal rate (from the 2002 Rate Case)

Financial Summary and Revenue Requirement Calculation - *Expected Cost to Customer*

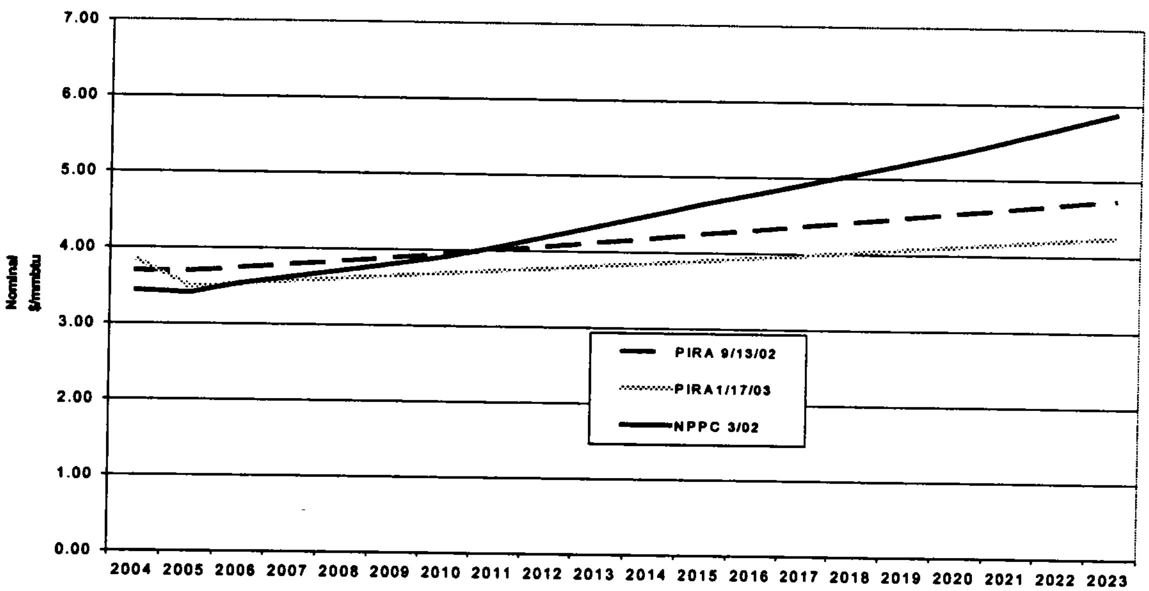
- Expected Cost to Customer is the point at which various alternative portfolios will be measured
- Expected Cost to Customer in the portfolio model is calculated as follows:
  - The comparative incremental cost to customers for a particular resource portfolio is developed by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the variable emission cost from the existing PSE fleet, the cost of market purchases, and the revenue from market sales with the revenue requirements from the new resource portfolio over a 20-year period
  - The NPV of the 20-year strip of incremental costs to customers is then calculated at the pre-tax WACC
  - The NPV of the Expected Cost to Customers are for comparative purposes only

APPENDIX J
KEY ASSUMPTIONS FOR AURORA MARKET POWER PRICE FORECAST

Gas Prices

PIRA Energy Group forecasts for the primary hubs were updated in January 2003, replacing the September 2002 PIRA forecast which was an input for the December 2002 Draft LCP. An alternative forecast, published in March 2002, was available through NPPC. The PIRA forecast for the Sumas hub more closely tracks the current forward market and has a less steep escalator than the NPPC forecast

Exhibit J-1
Natural Gas Forecast: Sumas

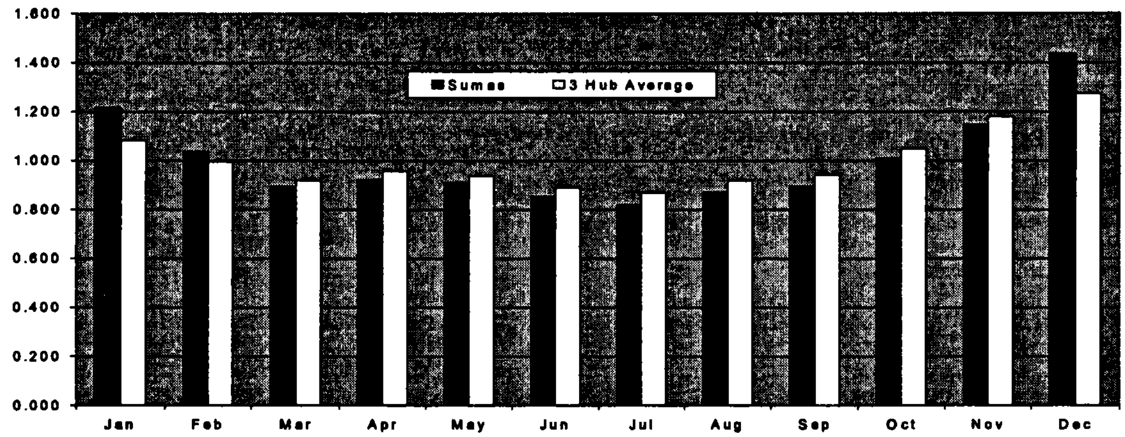


The PIRA forecast includes monthly estimates for 2004, then annual values for 2005, 2010 and 2015. The gas prices for the other years, up to 2023, are estimated with arithmetic interpolation and geometric extrapolation.

Each annual price requires that a monthly shape factor be applied to generate 12 monthly prices. The monthly shape factors are the average of the three northwest hubs, Sumas, AECO and Rockies, for the years 1991-1999. More recent data do not have any consistent pattern and the prices show extreme volatility and randomness.

The monthly shaping chart illustrates the traditional pattern of higher prices in the winter and lower in the summer. The three-hub average was applied to all eight hubs in the model other than Henry Hub which has its own monthly shaping.

Exhibit J-2
Monthly Shaping



Electricity Demand

AURORA divides the WECC into 13 subregions with individual growth rates. Exhibit J-3 lists the regions along with the new and previously assumed long-run regional growth rates. The new growth rates were adopted from the NPPC, "Draft Forecast of Electricity Demand of the 5th Pacific Northwest Conservation and Electric Power Plan," August 2, 2002. Short-run demand was adjusted downward to take into account the current recession, following the assumptions in the NPPC's 5th Draft of Wholesale Electric Price Forecast. Intermediate-term growth rates were increased so that the long-run growth rate was unchanged.

Exhibit J-3
Regional New and Previous Demand Rates

Region	New Demand (%)	Previous (%)
OR / WA / No. ID	1.50	1.53
No. California	1.71	1.63
So. California	1.87	1.63
British Columbia	1.53	1.53
Idaho South	1.71	1.53
Montana	0.90	1.53
Wyoming	0.23	2.37

Region	New Demand (%)	Previous (%)
Colorado	1.22	2.37
New Mexico	2.43	2.45
Arizona / So. Nevada	1.39	2.45
Utah	2.32	1.53
No. Nevada	1.65	1.53
Alberta	1.53	1.53

New Northwest Resources

In 2002 there were over 8,000 MW of new resources under development; however, most of the proposals did not make it beyond the planning stage. PSE currently assumes that 2,055 MW of new natural gas-fired resources will be available in the region. Presently three plants have been completed, with three under construction to be completed and on line by mid-2004. Exhibit J-4 lists those plants.

Exhibit J-4
New Natural Gas-Fired Resources

Plant	Owner/Developer	Capacity MW)	Online Date
Coyote Springs II	Avista-Mirant	260	Q2/03
Hermiston	Calpine	530	Online
Goldendale	Calpine	248	Q2/04
Big Hanaford	TransAlta	248	Online
Frederickson I	EPCOR	249	Online
Chehalis	Tractebel	520	Q3/03

Other well known gas-fired resources that once were expected to be developed, such as the Duke Grays Harbor plant, have not been assumed into the model. Wind resources that could be built in 2003, or later, were not assumed to be built. The AURORA database includes 473 MW of wind generation which their developers listed as going online in 2002.

New Resources

Three aspects of new resource costs need to be considered – the debt/equity ratio and their corresponding costs; assumptions about who will be building plants in the future; and the fixed and variable costs for each technology. To reflect the current market difficulties of merchant companies (IPP's), new projects will have to be financed with a mix of private equity and fairly high-yielding debt. However, it could be expected that this period of comparatively expensive cost of capital will give way to a long-term equilibrium with lower cost of capital assumptions.

Cost of Capital

Exhibit J-5 presents the cost of capital assumptions for PSE. The company expects that the spread between the return for debt and equity for the IOU's should be four to five percent, consistent with recent practice. The debt/equity ratio and the corresponding rates of return were used to determine a weighted cost of capital for each developer segment. For the IPP's the model uses the higher rates for years 2004 and 2005.

Exhibit J-5
PSE Cost of Capital Assumptions

Cost of Capital			
Return %	Public	IOU's	IPP's
Debt	6.5	7.5	10 to 8.5
Equity	0	11.5	30 to 17
Debt/Equity Ratio			
Debt	100	55	40
Equity	0	45	60
Total Cost (%)			
Weighted	6.5	9.3	22.0 to 14

New Resource Development

The second set of assumptions focus on which entities will be building new generation for each technology over the next 20 years. PSE used the developer mix assumptions made by the NPPC listed in Exhibit J-6.

Table J-6
NPPC Developer Mix Assumptions

	Developer Mix (%)			**Mix Weighted Cost of Capital**
Technology	Public	IOUs	IPPs	PSE
CCCT	15	15	70	**17.8 to 11.9**
SCCT	40	40	20	**10.7 to 9.0**

	Developer Mix (%)			Mix Weighted Cost of Capital
Wind	20	20	60	**16.4 to 11.3**
Coal	25	25	50	**15.0 to 10.8**
Solar	50	25	25	**11.1 to 9.0**

The developer mix percentages were applied to the weighted cost of capital for each developer segment (i.e. 6.5 percent, 9.3 percent, 13.6 percent) to produce a mix weighted cost of capital (values in bold font under PSE in Exhibit H-5) for each technology. The mix-weighted cost of capital was then applied to the investment costs discussed in the following section.

Timing of New Resource Development

In AURORA, new plants are brought online at the optimal time without regard to planning horizons. To replicate realistic planning needs, the higher overall cost of new resources was extended for additional years based on construction lead time. Simple cycle turbines and wind generation can be brought online in a year so the higher cost was extended through 2006. For combined cycle the higher cost is extended for an additional year through 2007. For coal, with it long lead time, the higher development cost is included through 2010 with a significant price drop in 2011.

Cost of Various Technologies

The AURORA model selects new resources for addition from a set of generic resources which will result in lowest overall cost. The cost and performance characteristics were provided by Tenaska for the combined cycle and simple cycle gas plants, as well as the coal plant. The wind data were provided by Navigant Consulting, Inc. and confirmed by other sources, while the solar data are from the NPPC.

The capacity of most new generation resources (i.e., the capacity of individual projects in MWs) can be scaled to meet the specific needs of the developer; hence there is not one correct size or correct estimate for each technology. Furthermore, with shared ownership, even greater flexibility of capacity can be achieved for a utility. PSE, in collaboration with Tenaska, selected a representative plant for each gas and coal technology based both on economies of scale and current development practices. Exhibit J-7 provides a list of the primary characteristics.

Exhibit J-7
Cost and Performance Characteristics

Technology	Capacity (mw)	Heat Rate (btu/kwh)	All-in Cost ($/kw)	Fixed O&M ($/kw)	Fixed Fuel ($/kw)	Variable O&M ($/mwh)
CCCT	516	6,900	645	11.00	15.55	2.00
SCCT	168	11,700	441	3.00	15.74	2.00
Coal	900	9,425	1,500	20.0	0	2.00
Wind	100	0	1,003	26.10	0	0
Solar	20	0	6,000	15.00	0	0.80

The CCCT represents a two-by-one configuration – two turbines with a heat recovery system. These plants are typically scaled by increments of about 250 MW, with variations around those figures depending on specific configurations.

The SCCT represents a lower-cost traditional peak using "frame" FA or EA gas turbines in simple cycle. More expensive aero-derivative plants are available which have a better heat rate at a much higher cost. Throughout the industry and its literature, one can find a wide variety of capacities, heat rates and costs for the numerous simple cycle options. The least-cost option is site and application dependent. The costs provided by Tenaska are based on the same assumptions as the combined cycle and coal plants which allows for a fair comparison between the technologies. For example, the SCCT listed starts with an EPC cost (engineering, procurement and construction) of $327/kw before taking into account "soft" costs such as insurance, contingencies, and costs related to financing, startup and spares etc. before arriving at a total installed capacity cost of $441/kW.

The coal plant represents a new site with a supercritical boiler design. An alternative would be a plant with two percent to four percent lower costs but with a two percent to four percent higher heat rate. Again the least-cost option depends upon the site and application.

The wind plant is based on the assumption that 100 MW is necessary to achieve economies of scale.

K

APPENDIX K
EMISSIONS CONSIDERATIONS AND WIND PRODUCTION TAX CREDIT

Emissions

Sulfur Dioxide

Currently SO_2 regulations apply to existing and future PSE plants. Title IV of the Clean Air Act set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase implementation of the SO_2 regulations applicable to fossil fuel-fired power plants.

Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Emissions data indicate that 1995 SO_2 emission at these units nationwide were reduced almost 40% below their required level.

Phase II, which began in 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing a total of 2,000 units. The program affects existing utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units.

A market-based allowance trading system was established to implement the regulations. Affected utility units are allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year. For each ton of SO_2 emitted in a given year, the utility must retire one allowance. Allowances may be bought, sold or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the Clean Air Act to protect public health. During Phase II of the program, the Act set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO_2 allowance allocations to utilities.

Nitrous Oxide (NO_X)

PSE is not currently subject to NO_X mitigation regulations. However, other portions of the country are subject to NO_X mitigation regulations. These regulations could be a proxy for what may eventually apply to the western United States.

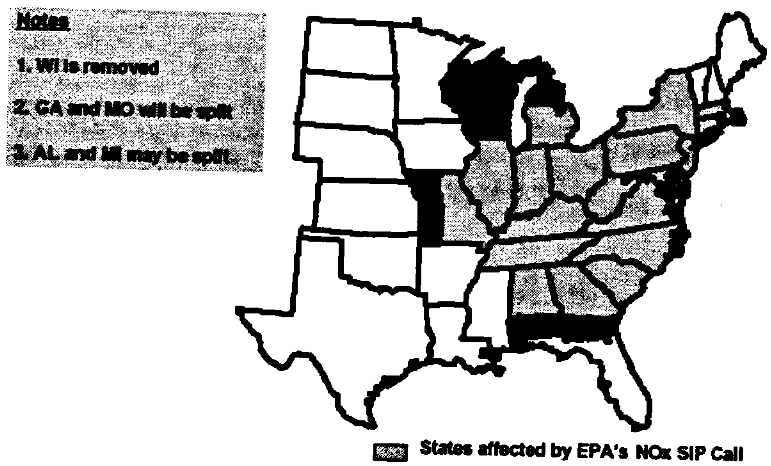
Section 126 of the Clean Air Act allows states to petition the EPA for a finding that sources from upwind states contribute significantly to non-attainment, or interfere with maintenance of national ambient air standards in the state. If a source receives such a finding, the source must either shut down in three months, or comply within three years with emission schedules set by the EPA. Through 1998 eleven states (CT, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT) and the District of Columbia have petitioned EPA to find that certain major stationary sources in upwind States emit NO_X emissions in violation of the Clean Air Act's prohibition on amounts of emissions that contribute significantly to ozone non-attainment or maintenance problems in the petitioning State.

These petitions eventually led to the 1998 "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone" (the " NO_X SIP Call"). Nineteen states and the District of Columbia were required to submit rules for implementation of Phase I by 10/2002. Phase I is expected to achieve 90% of the required reductions. Exhibit K-1 identifies the NO_X SIP Call area.

On December 17, 1999 the EPA finalized the Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Regional transport of Ozone (commonly referred to as the Section 126 final action). As a result of this action, each affected facility will participate in a federal NO_X emissions cap-and-trade program, aimed at reducing interstate ozone transport. Compliance is mandated by May 1, 2003.

Exhibit K-1

States Required to Submit Under SIP Call



Source: EPA

Clear Skies Act of 2003

H.R. 999 was introduced in the U.S. House of Representatives and S.B. 485 in the U.S. Senate in February 2003 to implement the tenets of the Bush Administration's Clear Skies Initiative. Clear Skies would require mandatory reductions and cap emissions of sulfur dioxide SO_2, NO_X, and mercury from electric power generation nation-wide. A mandatory, market-based cap and trade program for power generators would build upon the Clean Air Act to facilitate achievement of the initiative's goals. Exhibit K-2 outlines the goals of the Clear Skies Initiative.

Exhibit K-2
Clear Skies Initiative Goals

	Actual Emissions in 2000	Clear Skies Emissions Caps		Total Reduction
		First Phase of Reductions	Second Phase of Reductions	
SO2	11.2 million tons	4.5 million tons in 2010	3 million tons in 2018	73%
NOX	5.1 million tons	2.1 million tons in 2008	1.7 million tons in 2018	67%
Mercury	48 tons	26 tons in 2010	15 tons in 2018	69%

Source: EPA

The western portion of the US would be included in all three reduction programs, introducing NO_X regulations for the first time in the region.

Carbon Dioxide Legislation

In response to the introduction of the Clear Skies Act of 2002, Senators James M. Jeffords (I-VT) and Joseph I. Lieberman (D-CT) requested the EPA to analyze the impact of reducing CO_2 emission levels to in 1990 levels – the same level proposed in the Kyoto Protocol to the United Nations Framework Convention On Climate Change. Senator Lieberman and John McCain (R-AZ) introduced legislation in January 2003 modeled after the acid rain trading program of the 1990 Clean Air Act Amendments. This legislation seeks to return to 2000 carbon dioxide emission levels by 2010.

Many states are also pursuing state-level CO_2 mitigation programs. In June 1997, Oregon adopted a CO_2 standard for new energy facilities. The enabling legislation authorized the state's Energy Facility Siting Council to establish CO_2 standards for base load natural gas plants, non-base load power plants (all fuels), and non-generating energy facilities (all fuels). Pursuant to the legislation, the Council set up the rules to implement the standard in March of 1999. As an example of the implementation of these rules, the Hermiston Power Project is expected to have gross CO_2 emissions (i.e., over 30 years) of 50.2 million metric tons (MMT) (13.7 MTCE). The CO_2 standard offsets required for this project are 5.5 MMT CO_2 (1.5 MMTCE) and will be met through a monetary path offset value of $3.6 million.

California has also pursued CO_2 mitigation initiatives. On July 22, Governor Gray Davis signed into law a bill that provides authority to the California Air Resources Board (CARB) to consider CO_2 in their regulation of air emissions. Other governors have indicated an interest in considering similar legislation.

Production Tax Credit

In 1992, the Energy Policy Act was signed into law and included enactment of a Production Tax Credit (PTC) under Section 45 of the Internal Revenue Code of 1986. This credit was available to corporate entities building new renewable energy production facilities such as solar, biomass, wood chip, geothermal and wind power production plants. At its inception, the tax credit was $0.015 per kWh. The PTC value has increased each year by the official rate of inflation and applies to the first 10 years of equipment operation. The current PTC rate is approximately $0.019 per kWh.

The credit is available to new renewable energy facilities placed into commercial service after enactment of the law, and prior to the latest deadline, December 31, 2003. On March 9, 2002, the President signed the Job Creation and Worker Assistance Act of 2002 into law. Section 603 of the Act extended the production tax credit for wind, retrospectively, from December 31, 2001 to December 31, 2003.

Currently, the future of the PTC remains uncertain although a number of energy bills being considered at the federal level propose extensions of the PTC beyond 2003. Until the future of the PTC is resolved, the pressure on developers to begin projects this year in order to take advantage of the PTC will be significant. After that time, without an extension of the PTC, the economic outlook for new wind developments would be dampened relative to wind facilities leveraging the PTC as well as other conventional resource options.

The congressional tax committees originally sponsored the PTC legislation in order to encourage the development and utilization of wind energy with the intent that the PTC would enable wind energy to compete with conventional energy resources. Some have argued that an extension of the PTC through December 31, 2006 is necessary to provide wind developers with a level of certainty and stability that would allow the technology to further mature. Moreover, supporters agree the extension would stimulate the wind industry to achieve greater economies of scale, as well as enhancing wind's ability to compete with conventional alternatives.

Recent Legislative Activity

During the 107th Congress, a comprehensive energy bill passed the House and Senate, and went before a conference committee. Negotiations over the bill broke down, and the legislation died in Committee at the end of 2002. The energy legislation passed by the House and Senate would have extended the renewable energy production tax credit for an additional two years.

During the current Congress, Sen. Gordon Smith (R-Ore.) introduced a bill in January 2003 to extend the PTC through January 1, 2014. A similar bill introduced in the House by Representative Mark Foley (R-Fla.) seeks a five-year extension. Energy legislation will be addressed by this Congress and most speculate the PTC extension would be a component of any comprehensive legislation.

APPENDIX L

DISCUSSION DRAFT

March 25, 2003

Puget Sound Energy

Policy Statement Regarding the Promotion and Use of Renewable Energy Resources

Definition of Renewable Energy

For purposes of this Policy Statement, "renewable energy" means the electricity, gas or mechanical energy produced from facilities that are fueled by: (a) wind, (b) solar energy, (c) geothermal energy, (d) landfill gas, (e) municipal solid waste, (f) waste tires, (g) industrial by-products, (h) gas recovered from waste treatment facilities, (i) biomass, (j) wave or tidal action and, (k) qualified hydropower as defined in RCW 19.29A.090.

Our Policy

Puget Sound Energy ("Company") believes that renewable energy resources can and should play a role in meeting the incremental needs of its customers and become an important part of its resource supply portfolio beginning in 2004. Cost effective renewable energy resources can diversify fuel sources, enhance fuel price stability, provide location related benefits on the electric grid, reduce incremental air emissions, provide economic solutions to the disposal of various waste streams and stimulate local economic development.

The Company believes it should encourage the use of renewable energy resources by: a) using such resources to help meet its own-use requirements, b) encouraging its employees to use renewable energy resources at home, c) promoting appropriate renewable energy development and use by its customers, d) promoting the use of renewable energy resources in appropriate community applications through targeted education and demonstration projects, and (e) promoting the commercialization of cost effective renewable energy projects.

Many renewable energy resource applications are of a relatively small-scale with unit economies that may not compare favorably with the unit economies large conventional central generating plant alternatives. Accordingly, the scale and rate of their adoption and deployment by the Company must include consideration of the ultimate price impact upon the Company's retail prices and its customers. Further, some important renewable resource opportunities depend upon special federal tax depreciation and financing incentives for their commercial viability. Viable renewable energy projects that can be permitted, financed, constructed and reliably operated on a timely basis are of particular interest to the Company.

The Company's acquisition plan for renewable resources will include exploration of direct ownership through development and acquisition, use of bilateral contracts, and general solicitations. Any and all such means will be evaluated to secure appropriate renewable resources that complement the Company's goals of fuel diversity, price stability and supply reliability. Opportunities to pursue the integration of renewable resources into the Company's supply portfolio will be sought with the goal of gaining direct experience with managing and relying upon such resources to meet its customers' energy needs.

For small-scale customer side renewable energy applications, the Company supports the net metering standards adopted in 1998 that facilitate renewable energy development within the Company's customer base as well as across Washington. Further, the Company proposes to increase to 50 kw from the current 25 kw the size of the machine permitted under its net metering tariff. Net metering allows customers' electric meters that have generating facilities to "turn backward" when their generators are producing energy in excess of their demand, and would enable customers to use their own renewable generation to offset the cost of their own consumption at retail rates over a billing period. Such an approach involves customers more directly in renewable energy utilization, but also yields specific benefits to the Company including potential improvements to system load factors and additional energy resources within the service area.

Our Goals

- ***Electric Resource Portfolio Goals***. The results of the Company's current least cost planning efforts indicate that wind resources (or its equal) could serve at least five percent of its retail electric customers' energy needs with renewable resources by the year 2013. Higher standards of reliable energy supply described in the Least Cost Plan suggest that renewable energy could be targeted at the ten percent planning level. Such targets would necessitate acquiring approximately 125 and 250 average megawatts of renewable resources, respectively, for the Company's electric resource portfolio during the next ten years. The Company is continuing to consider renewable resources on the basis of cost and risk in its Least Cost Plan. Further assessment will include investigation of strategies and specific transactions to integrate renewable resources into the overall supply portfolio to meet ten percent of retail electric customer energy needs by 2013.

- ***Own-Use Goals.*** Beginning in 2004, the Company will acquire renewable energy for 50% of its own-use/own service territory requirements and will acquire 100% of such requirements beginning in 2006. The Company's estimated own-use annual load is approximately 28 million kwhr's.

- ***Employee Goals.*** The Company will set_goals and develop a five-year plan for the use of renewable resources by its employees.

- ***Customer Goals.*** The Company will set goals for renewable energy use by its customers. Such goals may include, but not limited to, use of green pricing programs, adoption of net metering technology, additions of renewable resources to its overall supply portfolio and creation of programs to involve customers in the demonstration and adoption of renewable resources for their own direct use.

Action Plan

The Company will organize managerial and financial resources to identify and utilize or acquire renewable resource projects appropriate to its energy needs, cost considerations and customer and community interests. Additionally, the Company will encourage entrepreneurial initiatives in its service territory to identify and implement appropriate renewable resource projects that are intended either as merchant power, customer end-use consumption with net metering options, and purchase power alternatives.

The Company realizes that the opportunity to economically obtain renewable resources can vary greatly over time. Such opportunities are impacted by shifts in technology, transmission constraints, capital markets, federal and state tax policy, wholesale power markets, markets for various waste products, environmental regulations and public acceptance of the impacts such resources have on local communities and the environment. The Company recognizes that many renewable resource projects have unusual and even unique market and siting attributes. The Company notes its concern that there may be a dearth of specific, commercial scale renewable energy development opportunities in its service territory that are economically attractive and readily able to be permitted. Accordingly, it is the intent of the Company to become knowledgeable about renewable resource opportunities and to obtain such resources by proactively engaging in both development and acquisition transactions. In pursuing such development opportunities and/or making such acquisitions, the Company will consider not only cost criteria, but also the ancillary benefits of appropriate scale and local impacts, reduced price volatility, customer and community needs.

Annual Policy Review

This policy shall be reviewed not less than annually by the Company and shall be considered in each Least Cost Plan the Company creates in connection with its obligations under various laws and regulations of the State of Washington.

Version 3/25/03

APPENDIX M
WIND RESOURCE INTEGRATION ISSUES

Wind As a Resource Option

PSE's electric resource strategy includes a goal of meeting five percent (133 aMW) of its customer energy loads through wind resources. In order to meet this goal, and strive for a goal of meeting 10 percent of its electric customers' needs from renewables, PSE must address issues related to integrating wind into its portfolio. Recently, wind energy has been attracting greater interest among developers, utilities and consumers alike as a viable resource. The drivers of this interest include the continuing improvement in the competitiveness of wind energy economics, the recent increase in natural gas prices along with increased price volatility, and the growing consumer interest in green pricing programs and renewable energy in general

For PSE, the attractive aspects of wind include immunity to fuel price volatility, absence of emissions, opportunity to diversify the supply portfolio, ability to offer a green product directly to customers, and the potentially favorable economics. In the short-term, PSE has signed a 12-month contract to purchase output from a wind facility in order to gain first-hand experience with dispatching this technology within the Company's portfolio. Critical to the further integration of this technology is gaining a better understanding of the implications of integrating wind and relying upon it as a part of the Company's supply portfolio. To do this effectively, PSE needs to consider a number of issues in its evaluation. These issues include:

- The intermittency of wind resources
- Balancing system reliability with wind interconnection
- Understanding the match between wind resources and PSE's system peak
- Accessing the best wind resources in the region
- Addressing fundamental facility interconnection

The remainder of this Appendix examines each of these issues along with addressing potential solutions that PSE can exercise to integrate wind into its supply portfolio.

Intermittency of Wind

At the forefront of its efforts to integrate wind into its portfolio, PSE must consider the issue of wind intermittency. This issue refers to the simple fact that when the wind does not blow, power is not generated. In addition, it is difficult to accurately predict output from a wind facility on an hour-to-hour and on a day-to-day basis due to the variability of wind resource availability. This characteristic of wind facilities poses specific challenges for PSE in considering how best to integrate it with the other resources that it operates and dispatches in meeting customer loads on a daily and hourly basis.

The issue of predictability itself has several dimensions such as hour-to-hour, day-to-day, and matching supply to load. Under each set of circumstances, wind exhibits different attributes. As PSE continues to assess the best applications for wind, its predictability attributes will reflect the particular circumstances being considered. In the first case of hour-to-hour predictability, wind tends to have relatively predictable performance levels. Since utilities schedule supplies on an hourly basis, the fact that wind performance becomes more predictable the closer you get to the hour of need is supportive of its integration. It has been claimed by some that within two hours, the prediction of wind availability can be made with a high degree of confidence with variability of +/-10 percent. As you get further away from the hour of need the predictability declines.

In the second case of day-to-day predictability, PSE pre-schedules on a day-ahead basis to establish its resource commitments. Day-ahead forecasts function to provide an operator such as PSE with a sense of available generation for the next day. In the case of wind, the fact that the predictability is less on a day-ahead basis than hour-to-hour does present additional challenges for incorporating wind resources. However, the predictability of wind during the summer is better (when winds are strongly correlated with rising temperatures) than during the winter (when wind resources are driven by storms). From PSE's perspective this creates an additional consideration when looking at the best applications for wind as it relates to the Company's integrated portfolio of resources. For most resources that the Company relies upon, both owned assets and purchased power, PSE schedules on a day-ahead basis thus the issue for PSE is one of blending wind's predictability attributes over the year with the rest of the resources in its mix.

Balancing System Reliability

Beyond the hour-ahead and day-ahead predictability of actual wind resource availability, PSE faces the issue of load variability and potential imbalances. Based on wind resource availability studies prepared in the region, no correlation exists between wind variations and load variations. Although this fact makes it highly unlikely that wind can be relied upon as a load following resource, it does not mean preclude the use of wind as a forward planning resource.

PSE recognizes that reliance on wind power will have different probabilities associated with it than other resources and that the probabilities will change from season to season.

The effects of wind on other resource planning and operation activities differ in the long-and short-term and vary in how they affect PSE's resource planning, acquisition, and operation efforts. In the long-term, wind resources can be viewed as a consistent resource providing needed energy on an annual basis. One could argue that wind has more consistency in terms of the energy contribution from year to year than hydro resources. However, challenges arise when taking into account the timing of availability in the near term (day to day), which is more consistent with hydro than wind. Nevertheless, PSE views wind resources as a potentially viable energy resource for use in meeting its annual energy needs. As noted above, wind resource availability on a season-to-season basis may not be consistent, however, the summer months tend to be more consistent for wind than the winter months.

Match Between Wind and System Peak

In the short-term, resource operation issues for wind are more pervasive than the planning and acquisition activities, due to the increased importance of resource predictability. The shorter the horizon, the more PSE has to ensure the availability of the appropriate mix of resources for meeting projected loads. The system operator will ramp up and dispatch resources and rebalance the portfolio on a real-time basis to optimize the Company's operational costs in parallel with reliably meeting customer end-use loads. An intermittent resource can potentially impose additional costs on an operator as a result of unanticipated changes in resource output.

In terms of resource adequacy, or reliability, wind does impose some unique challenges that can result in cost implications for PSE. As a control area operator, PSE has responsibilities to meet reserve margin targets. Intermittent resources such as wind, which like load can contribute to the need for maintaining a higher reserve margin requirement, cannot be relied upon to meet these reserve margin requirements and could subject the Company to penalty exposure. Consequently, PSE must either acquire additional resources to meet its needs or hold some of its existing resources in reserve. While wind can certainly satisfy average annual energy requirements, it cannot be counted on to satisfy regional reserve margin targets. The other cost implication of wind resource reliability is in the area of off-system sales. The less reliable the resource, the less the Company can rely on that resource (as part of an integrated portfolio) to market excess capacity and/or energy when PSE system loads are lower than the resources available in the portfolio. Shortfalls in resource availability have to be covered by other resources in the portfolio, which diminishes the off system sales opportunities that could be pursued.

Best Regional Wind Resources

For purposes of the Least Cost Plan, PSE assumed a reliance upon wind resources within the Northwest region versus other adjacent states that may have better wind resources, but would be subject to large wheeling charges. PSE is cognizant that most of the best wind resources are not close to either existing high-voltage transmission or major load centers. In spite of this limit, a number of developers have identified potentially workable sites, with proximity to transmission lines and locations within the PSE system. PSE must determine its transmission capabilities in these areas and determine whether they require capital improvements and/or additional wheeling rights.

Given its intermittent nature and its dependence on the location of the resource, wind facilities are often at a competitive disadvantage to power generating facilities relying on traditional resources such as coal, gas, and nuclear. Transmission scheduling policies are geared toward dispatchable facilities whereby one knows on a day-ahead basis how much and how long capacity will be needed, with a fairly high degree of confidence that it will be used or not used. Wind variability makes the proportional impact of transmission costs relative to actual utilization much higher than for the conventional facilities, due to the take or pay nature of firm service. Transmission operators rely on schedules and reservations to optimize the utilization of the system for all users. Deviations from these result in costs that must be allocated among the users. Typically, the allocation of these costs is done based on who was responsible for the deviation.

Facility Interconnection

The point of interconnection for a wind facility, and the turbine/generator technology employed play very important roles in determining the impact that facility will have on the system. Strong interconnected transmission or distribution systems have greater voltage stability, and are not as impacted by the voltage response of non-synchronous wind generators to faults, switching actions, and load changes. Depending on the turbine/generator technology, strong transmission and distribution system can absorb significant amounts of intermittent wind generation with relatively modest impacts on the quality of power. A weak, voltage limited system, on the other hand, will not be able to as easily absorb these intermittent flows, and the generators may be susceptible to remote faults, and switching actions due to voltage instability. Where voltage support is weak and at remote parts of the PSE system, considerations for wind resources will include their intermittent output during peak loads, voltage instability, and their susceptibility to faults on weak systems. Future opportunities to integrate wind will be considered at both the transmission and distribution levels.

Potential Solutions for Integrating Wind

Although PSE recognizes the challenges to integrating wind into its portfolio, the Company realizes the advantages such a strategy offers, PSE's recent contract to take delivery of wind-generated electricity will provide the Company with valuable experience addressing the intermittency and other issues. PSE also acknowledges that having pre-defined interconnection requirements provide a particularly important component necessary to facilitate the development of wind within the control area. For developers, this would send a clear signal of PSE's confidence in its ability to manage the integration of wind resources into the region's supply mix while managing its interconnection with the transmission system. Having responsibility for maintaining the safety and reliability of the grid, PSE has continued to maintain strict control over the terms and conditions for interconnection to the grid by non-utility generators. Gaining first hand experience with a small amount of wind generation, either owned by a third party or by PSE, would give PSE first-hand empirical data regarding the issues raised by the intermittence of wind. This would enable PSE to more effectively integrate wind into its portfolio.

The potential of PSE offering a green product to customers on a regulated basis represents an option for greater wind integration. Across the country, a number of green-pricing programs have been implemented by investor-owned utilities, municipal utilities, and retail power marketers. Green pricing allows customers to pay a premium to receive a percentage of their electricity from a renewable resource. To implement this strategy, PSE would first have to design a proposed product and pricing structure that it can take to the WUTC for review and approval. This step must be taken due to the requirement for PSE to obtain special rate treatment to allow the Company to charge interested customers a rate that differs from the standard tariff rate under which they currently take service. Once approved, PSE would be able to market the program to its customers, possibly relying on wind resources that it owns or purchases from another company. While green pricing programs have had mixed results across the nation in terms of customer interest and willingness to pay, PSE has confidence that a green-pricing program can be a viable means of integrating wind into the Company's supply mix on a cost-effective basis.

As detailed in PSE's Two-Year Action Plan in Chapter XVI, PSE has a commitment to study wind integration issues. This Appendix not only offers PSE's preliminary thoughts on the challenges it faces, but also serves to demonstrate PSE's commitment to identify, address and develop solutions to the challenges of integrating wind into its system.

N

APPENDIX N
GAS RESERVE BACKGROUND

The data in this table were combined from a number of sources in order to construct a picture of the overall reserve position in the United States and Canada.[1] Particular focus is given to those gas production areas that are expected to affect PSE directly.

Since 1994, US gas reserve additions have exceeded production in all years except 1998.[2] Canada, however, has seen a decline in proved reserves. Continued exploration and development of natural gas reserves will provide production adequate to meet most of the projected demand. Over longer periods of time, as reserve and gas production levels change, the development of gas reserves in other regions might take on greater significance to PSE. Given the continued development of gas reserves accessible from Duke Transmission, GTN, and NWP, PSE does not expect shifting purchases to other supply areas to be a material consideration in the foreseeable future. Exhibit N-1 provides a summary of North American reserves.

US Reserves

Additions to natural gas reserves in the US have exceeded production in every year but one prior to 2001. Existing gas reserves in the lower-48 are estimated to be 183 Tcf. At current production levels, these reserves will be adequate to supply approximately nine years of gas demand at current consumption levels. As with Canada, significant amounts of gas reserves remain unproved.

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[1] While some liberty was taken with combining these data from different sources, the scale and relative allocation of the gas reserves was maintained.

[2] According to the EIA, this year [1998] was characterized by extremely low energy prices and accounting adjustments that affected reserve calculations.

Exhibit N-1
Summary of North American Gas Reserves

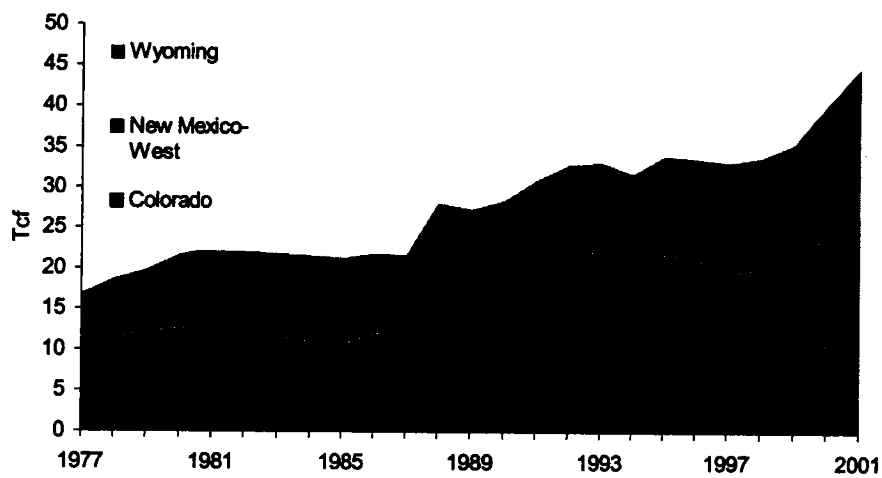
	ENERGY INFORMATION ADMINISTRATION	NATIONAL PETROLEUM COUNCIL	POTENTIAL GAS COMMITTEE	CANADA	TOTALS & AVERAGES
Lower – 48 Proved	183	157	157		
Lower – 48 Unproved	1,073	1,309	738.76		
Total Lower – 48	**1,256**	**1,466**	**895.76**		
Alaska Proved	10	10	10		
Alaska Unproved	32.32	303	183.83		
Total Alaska	**42.32**	**313**	**193.83**		
Total U.S. Proved	193	167	167		**175.67**
Total U.S. Unproved	1,105.32	1,612	922.59		**1,213.3**
Total U.S. Reserves	**1,298.32**	**1,779**	**1,089.59**		**1,388.97**
Alberta Proved				42	**42**
Alberta Unproved				158	**158**
Total Alberta				**200**	**200**
British Columbia Proved				8.9	**8.9**
British Columbia Unproved				111.25	**111.25**
Total British Columbia				**120.15**	**120.15**
Mackenzie Proved				0.5	**0.5**
Mackenzie Unproved				12.3	**12.3**
Total Mackenzie				**12.8**	**12.88**
Other Canada Proved				8.7	**8.7**
Other Canada Unproved				458.35	**458.35**
Total Other Canada				**467.05**	**467.05**
Total Other Canada Proved				60.1	**60.1**
Total Other Canada Unproved				739.9	**739.9**
Total Canada				**800**	**800**
Total NA Proved					**235.77**
Total NA Unproved					**1,953.2**
Total NA Reserves					**2,188.97**

<u>Notes</u>

- *Exhibit does not include Mexico. Data covers estimates from 1999-2001. Highlighted areas include derived or estimated values.*
- *Data sources include National Gas Supply Association; Canadian Association of Petroleum Producers; U.S. Geological Survey, Province of Alberta, EUG Statistical Surveys, Province of British Columbia, Energy and Mines; Energy Information Administration, Natural Gas Outlook*

The northern Rockies and Wyoming basins have emerged as the fastest growing gas-producing region in the US. Shallow gas formations, low drilling costs, and IRS Section 29 tax credits[3] for coal bed methane have spurred a rapid development pace in this area. However, development of pipeline capacity adequate to transport this gas market has lagged behind gas production. Accordingly, gas supplies in these areas (and other regions, such as the San Juan Basin) are generally lower priced than those in other areas as they compete to gain access to the available capacity. Exhibit N-2 provides an overview of natural gas reserves in the Rockies, San Juan and Powder River Basin.

Exhibit N-2
Natural Gas Reserves in the Rockies, San Juan Basin, and Powder River Basin
1977 – 2001



Recently, the United States Geological Service (USGS)[4] revised its estimates for undiscovered natural gas reserves in these areas. In the case of the Powder River, and San Juan Basins, these revisions resulted in upward estimates of the amount of undiscovered gas in these regions. With its capacity positions on the Northwest system, PSE is well-positioned to access these growing gas reserves and participate in facilities expansions. Exhibit N-3 details these revised estimates.

[3] These tax credits expired on December 31, 2002, resulting in a drop in the gas exploration activity. Expectations are that the resumption of these credits will be re-visited in the next Energy Bill, although at a lower level.
[4] These revisions were published by the USGS between December 2002 and January 2003.

Exhibit N-3
Summary of Gas Reserves Accessible to PSE

GEOLOGIC AREA	MEAN ESTIMATE (TCF)	PERCENT CONVENTIONAL	PERCENT UNCONVENTIONAL	BASE YEAR OF ESTIMATE
Montana Thrust Belt	8.6	99.0	1.0	2002
South-western Wyoming	84.6	3.0	97.0	2002
Uinta and Piceance Basins	21.0	~1.0	~99.0*	2002
Powder River Basin	16.5	6.0	94.0	2002
San Juan Province	50.6	0.1	99.9	2002
Total	***181.3***	***6.8***	***93.2***	

** Characterized by the report as "nearly all".*

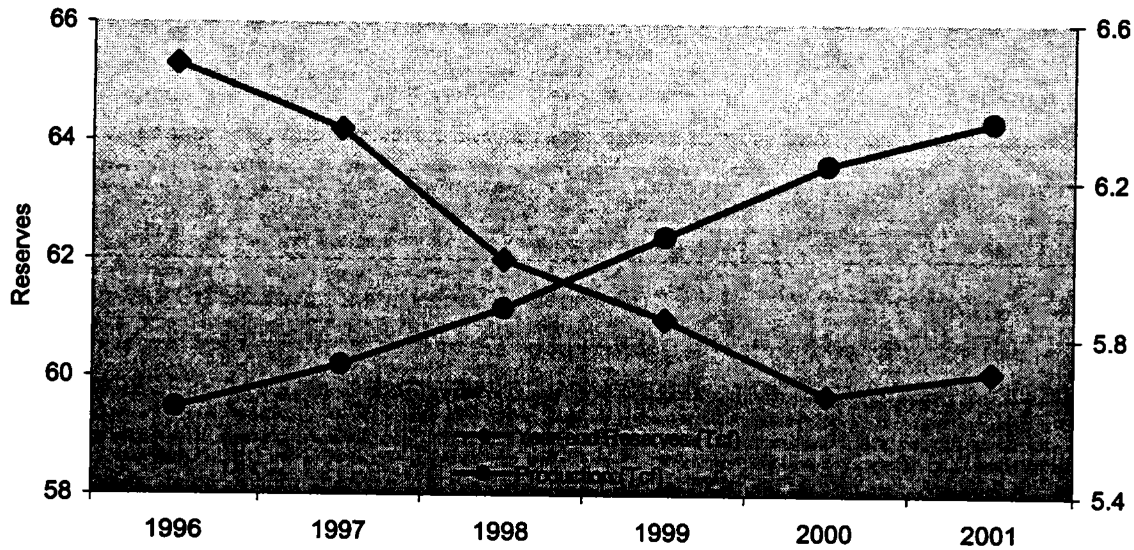
The potential for increased gas reserves, relatively low field prices, and high market prices make new pipelines and pipeline expansions attractive for these areas. A number of new pipeline projects are in the works to move gas east, west, and south from these regions to existing markets and pipeline systems. The Cheyenne Plains project (El Paso) plans to move gas from eastern Wyoming to existing pipeline systems in Kansas to support declining reserves/production from older gas reserves. Kinder-Morgan and Transwestern have both proposed to build new pipelines into Phoenix, Arizona, and on to interconnect with El Paso's southern system and deliver additional gas into southern California. Kern River has recently completed expansions into southern California, and plans to expand further.

Canadian Reserves

Alberta, the largest natural gas producer in Canada, produces almost 5 Tcf (13.6 Bcfd) in 2001. Estimated, proved reserves at year-end 2001 stood at 40.5 – 45.2 Tcf. These reserve estimates do not consider coal bed methane (CBM) gas reserves, which are thought to be significant. Additional, remaining reserves are put at approximately 155 Tcf, more than three times the estimate of proved reserves. Most of the recent gas drilling activity has been centered on shallow formations in the southeastern part of the Province. Over time, development activity will likely shift to wells with smaller pools and higher declining rates. Developmental drilling continues on the Ladyfern field, a major discovery in the northwestern part of the province. Nonetheless, Alberta projects that beginning in 2005, gas production will begin to decline two percent per year.

British Columbia produced a little over one Tcf (2.9 Bcfd) in 2001, the second largest gas producer in Canada behind Alberta. Gas reserves are concentrated in northeastern part of the province, with a recent, significant find (Greater Sierra - 2002) estimated to contain five Tcf. Since 1991, the estimated remaining, marketable gas for British Columbia has hovered around 240,000,000 e3m3 (8.56 Tcf) – the same in 2001 as it was in 1991. Against this backdrop of stable reserve estimates, annual production in British Columbia almost doubled between 1991 and 2001, moving from 15.8 e9m3 (1.5 Bcfd) to 29.9 e9m3 (2.9 Bcfd day).

Exhibit N-4
Canadian Natural Gas Proved Reserves and Production



Preliminary estimates for the reserves in Mackenzie Delta region are modest at 0.5 Tcf, but the potential gas reserves are expected to be significant. Debate over the best pipeline route to move natural gas from this region, and other reserves further west in Alaska, has heated up recently as higher gas prices have made production from these areas more attractive.

As the frontier gas development progresses, the new pipelines (from Alaska, Mackenzie Delta, or both) will likely tie into existing systems in Alberta, finding a ready market for the gas at the AECO Hub for markets south and east. PSE's capacity position on PGT provides strategic access to current and future gas supplies from Alberta and points north.