Gas Resources

PSE provides natural gas directly to 750,000 customers in Washington state. We also rely on natural gas to fuel increasing amounts of electric generation. As the need for this resource grows ever larger, so do our concerns about supply diversity. To develop a complete picture of the challenges that will confront us in the coming years, this IRP examines the gas sales portfolio as well as the combined gas sales and gas for generation portfolio.

I. Gas Resource Need

Consistent with PSE's previous IRPs and with the Washington state integrated resource planning requirements for natural gas utilities (WAC 480-90-238), this IRP develops an integrated resource plan for our gas sales customers. However, natural gas has become an increasingly important resource for PSE. Not only do we supply it for end use to more than 750,000 gas sales customers, we also use it as fuel to generate electricity.

Because our reliance on this resource is so significant – and growing – we believe that looking at the combined resource need for "gas sales" and "gas for generation" is crucial to developing an accurate perspective on the challenges and decisions that must be made in the years ahead. We are obligated to secure reliable supplies for both purposes.

Figure 6-1 illustrates total gas resource need over the 20-year planning horizon. The lines rising toward the upper right corner indicate the increasing (combined) demand for gas sales and gas for generation; the bars below represent current contracts for the pipeline transportation, storage, and peaking capacity. These resources enable PSE to transport gas from points of receipt to customers and generating plants. Where the demand lines rise above the existing resources bars – as they begin to do after the heating season of 2010-2011 – additional resources are required to meet peak capacity.

A wide range of variability is displayed among the seven demand scenarios plotted here. By 2029, a 200 MDth per day difference in need arises between the demand in 2007 Trends (the original reference scenario developed for this IRP in 2007) and the demand in 2009 Business as Usual (BAU) scenario (which was developed in early 2009). This reflects the high degree of uncertainty that exists today concerning future economic and regulatory conditions as well as commodity prices. Further, developing detailed long-term plans to supply gas for generation is difficult since gas transportation needs are highly dependent on the specific location of the generating plants. For example, plants located near a gas trading hub or storage facility need less pipeline capacity to transport fuel. On the other hand, generation plants located close to PSE loads need less electrical transmission. For gas transport planning purposes we assumed that all new gas-fired generating plants are located in the Puget Sound area.

Figure 6-1
Combined Gas Resource Need (Gas Sales and Gas for Generation)
Existing Resources Compared to Peak Day Demand

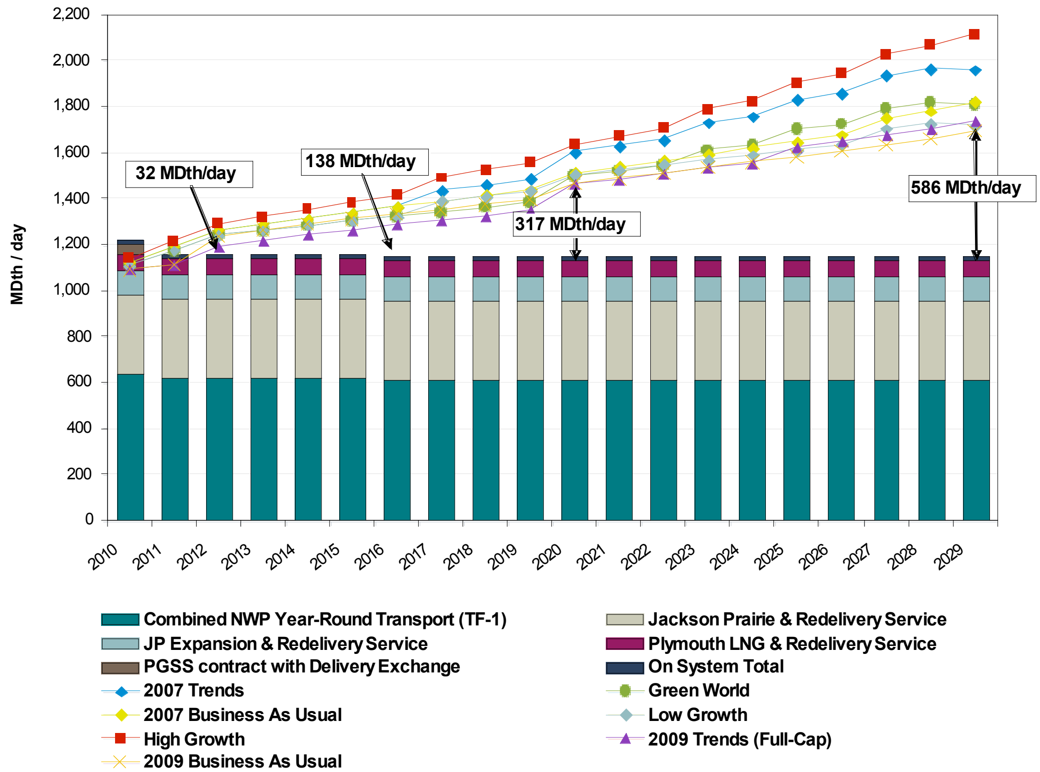
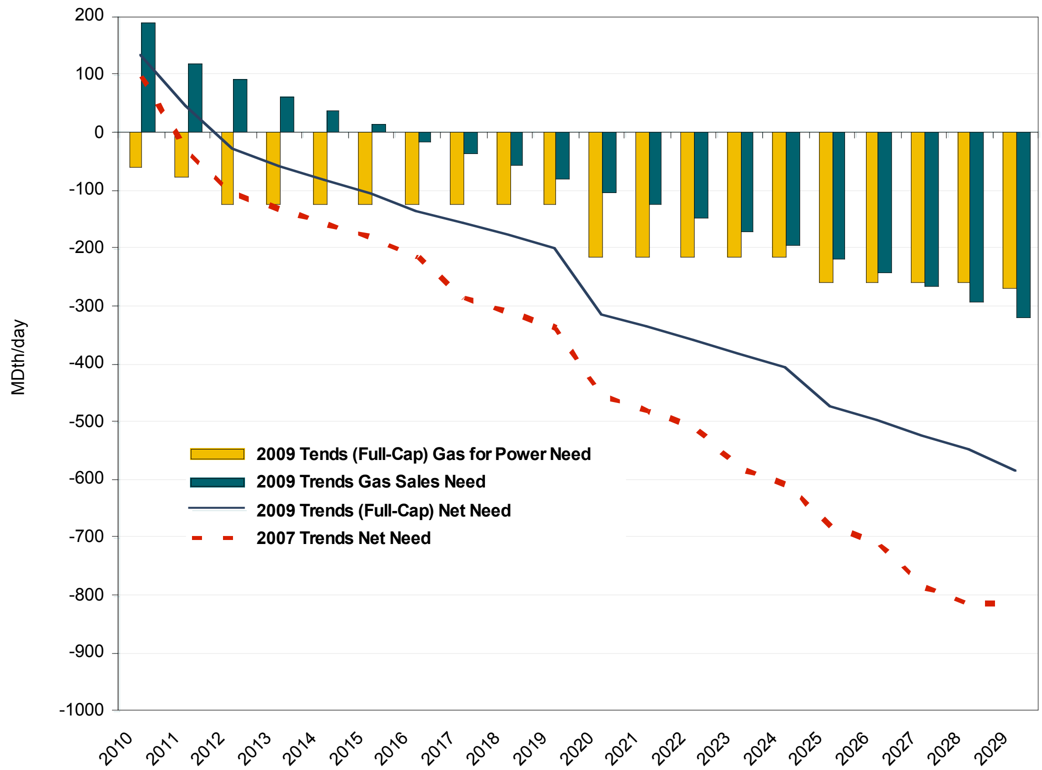


Figure 6-2 illustrates the gap between demand and existing resources shown in Figure 6-1, but also identifies which portion of that need originates with the gas sales portfolio and which portion from the electric generation portfolio. A closer look reveals that different needs are more pressing at different points in time.

Figure 6-2

Sources of Resource Need: Gas Sales Compared to Gas for Generation

Generation fuel is the most immediate and pressing need.



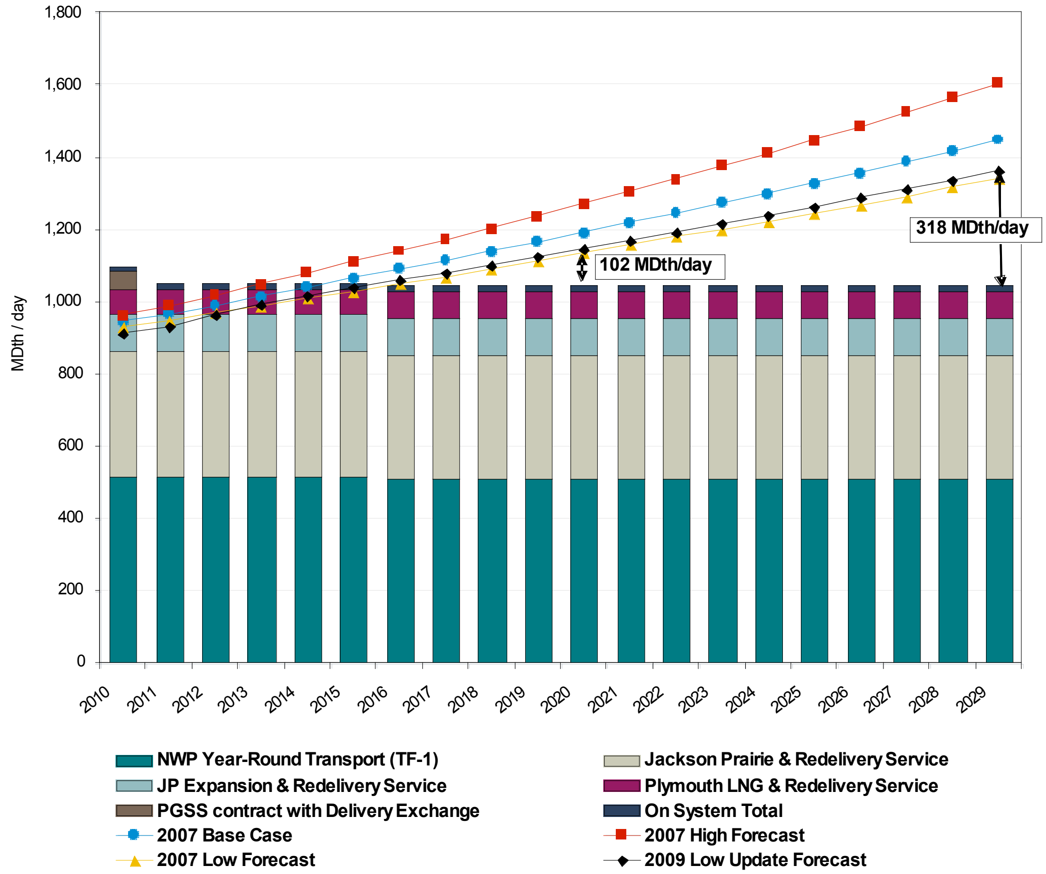
When the origin of need is examined, several points become clear.

- Fuel for electric generation is the most immediate and pressing need for approximately the first five years of the planning horizon. Additions are required starting in 2010.
- Gas sales need begins after the 2015-16 heating season.
- Generation fuel makes up the majority of the additional resource needed for the duration of the planning horizon (however, absolute amounts required for generation fuel are less than absolute amounts required for gas sales).

Gas Sales Resource Need

Figure 6-3 illustrates gas capacity need for direct sales customers under four different demand forecasts for the 20-year planning horizon. Again, the lines rising to the right represent demand forecasts; the bars below represent existing resources.

Figure 6-3
Gas Sales Resource Need
Existing Resources Compared to Peak Day Demand



Variation in the demand forecast has a strong influence on the timing of resource additions:

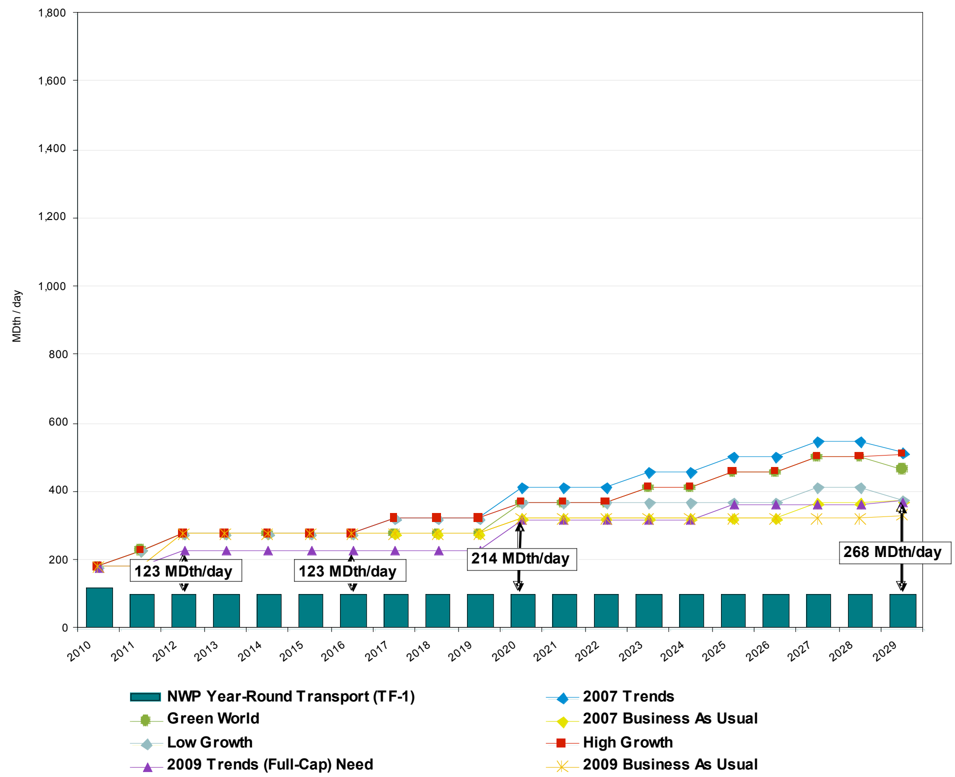
- Under the 2007 Base forecast, additional resources will be needed beginning with the winter of 2014-2015.
- Under the 2007 High demand forecast, additional resources will be needed by the 2013-2014 heating season.
- Under the 2007 Low and 2009 Low Update forecasts, additional resources will not be needed until the winter of 2016-2017.

Resource Need for Generation Fuel

All of the portfolios considered in the electric analysis contain higher levels of gas-fired generation than previous IRPs and Least Cost Plans, and this trend will continue for the foreseeable future.

Figure 6-4 illustrates gas for generation resource need by comparing existing resources with projected peak demand under all seven electric scenarios modeled.

Figure 6-4
Gas for Generation Resource Need
Existing Resources Compared to Peak Day Demand



Natural gas resource needs for electric generation are more immediate and increase more rapidly than resource need for gas sales, reflecting the addition of gas-fired generation in all possible futures.

- There are substantial increases in the amount of gas-fired generation during the first five years of the planning horizon in all seven electric scenarios.
- After five years, gas-fired generation continues to increase but the rate of increase begins to separate depending on the scenario.
- Note that Figures 6-3 and 6-4 are drawn to the same scale: While the gas required for electric generation is anticipated to increase faster than for the gas sales portfolio, the absolute amounts required are less than for gas sales, and are projected to remain so over the 20-year planning horizon.

The Need for Supply Diversity

As PSE's combined reliance on natural gas grows, diversifying the company's supply sources becomes more important. Here we outline PSE's concerns about concentration, identify potential advantages, and describe new opportunities that may make it possible to increase options. This IRP analyzes the combined gas portfolio in two ways – with, and without meeting a diversity requirement – in order to identify the cost of increasing supply options.

Currently, PSE's source of supplies is concentrated in the Western Canadian Sedimentary Basin (WCSB) in Northern British Columbia and Alberta. Figure 6-5 summarizes pipeline and storage capacity for the gas sales, gas for generation, and combined portfolios. The WCSB currently supplies

- nearly 70% of the pipeline capacity for the combined portfolio
- 65% of the gas sales portfolio
- 86% of the gas for generation portfolio

When the existing contracts for Rocky Mountain basin supplies expire in June 2011, the gas for generation portfolio will become 100% reliant on WCSB supplies.

Figure 6-5
Summary of Combined Gas Supply Sources
Existing Pipeline and Storage Capacity

	Current Capacity Jan. 2009 (MDth/day)					
Gas Source and Route	**Gas Sales**		**Gas for Generation**		**Total**	
British Columbia (Stn2 via Westcoast and NWP)	97	19%	47	39%	144	22%
British Columbia (from Sumas via NWP)	163	31%	57	47%	220	34%
Alberta (via TC-AB, TC-BC, GTN and NWP)	76	15%	-	0%	76	12%
Total Western Canadian Sedimentary Basin	**336**	**65%**	**104**	**86%**	**440**	**69%**
US Rockies (via NWP) (includes Clay Basin)	184	35%	17	14%	201	31%
Total US Rocky Mountains	**184**	**35%**	**17**	**14%**	**201**	**31%**
Total from Supply Regions	**520**	**100%**	**121**	**100%**	**641**	**100%**
Jackson Prairie (via NWP)	404	41%	50	29%	454	39%
Plymouth LNG (via NWP)	70	7%	-	0%	70	6%
Total from Storage	**474**	**48%**	**50**	**29%**	**524**	**45%**
Grand Total	**994**		**171**		**1,165**	

PSE is concerned about the following:

- **Concentration of risk.** As annual volume needs continue to rise, the concentration of PSE's already high exposure to WCSB market hubs will intensify.
- **Reliability.** Such a high reliance on one supply basin leaves PSE vulnerable to supply interruptions should well freeze-offs, forced outages, or pipeline disruptions occur.
- **Declining supplies.** Under some projections, the amount of gas available for export from WCSB will decline due to expanded needs for oil shale processing, which could result in upward pressure on prices.

Greater access to the Rocky Mountain basin offers several potential advantages:

- **Increased reliability.** In the event of supply interruptions from any one basin, more alternatives are available.
- **Access to lower cost supplies.** Currently, and at least through 2013, Rockies market hub supplies are priced significantly lower than Sumas hub supplies (for a more detailed discussion of price differentials, see page 6-13).
- **Purchasing flexibility.** Diversifying supply increases the ability to take advantage of short-term price differentials (volatility) between the Canadian market hubs (Sumas and AECO) and Rockies supplies.
- **Increased access to existing storage.** Increased access to PSE's existing Clay Basin storage would also increase the company's ability to supply the highly variable needs of gas-fired generation on daily and intra-day bases.

Until recently, potential sponsors showed little interest in construction of new pipelines across the Cascades. Now, new interest and plans are opening up new opportunities.

- Construction of new pipelines between the Rockies and the GTN pipeline in eastern Oregon (specifically to the Stanfield and Malin hubs) has drawn increased interest, and firm plans have been drawn up. The Ruby pipeline proposal is the furthest along in the process.
- Transport of Rockies gas from eastern Oregon to the I-5 corridor including into PSE's service territory has attracted interest and preliminary planning by PSE and others.
- The need for increased peak day supplies and pipeline capacity to deliver gas to the Northwest and the I-5 corridor is being recognized by other utilities and utility

organizations such as the Northwest Gas Association (NWGA). (see the NWGA's Fall 2008 Northwest Gas Outlook at www.nwga.org)

PSE strives to balance low cost and "reliability in diversity" in meeting both gas sales and gas for generation needs. The need for diversification is growing more urgent as the amount of gas used for electric generation increases.

II. Existing Gas Resources

A. Gas Sales Resources

1. Supply-side Resources, Gas Sales

Supply-side gas resources include pipeline capacity, storage capacity, peaking capacity, and gas supplies.

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities, or interconnections with other pipelines. “Upstream” pipelines deliver gas to the direct pipeline from remote production areas, market centers, and storage facilities.

Direct-connect Pipeline Capacity. All gas delivered to our gas distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold the following capacity with NWP.

- 520,053 dekatherms per day (Dth per day) of firm, year-round TF-1 transportation capacity
- 110,704 Dth per day of special winter-only firm TF-1 transportation capacity
- 413,557 Dth per day of firm TF-2 capacity

TF-1 transportation contracts are firm contracts, available 365 days each year. TF-2 service is for delivery of storage volumes during the winter heating season only, and therefore has significantly lower annual costs than the year-round service provided under TF-1. The special winter-only TF-1 service has similar characteristics and pricing as TF-2 service.

Receipt points on the NWP contracts access supplies from four production regions: British Columbia, Alberta, the Rocky Mountain area, and the San Juan Basin. This provides valuable delivery point flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity. To transport gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

Figure 6-6 provides a general picture of existing pipeline transportation resources in the Pacific Northwest.

Figure 6-6
Northwest Regional Gas Pipeline Map

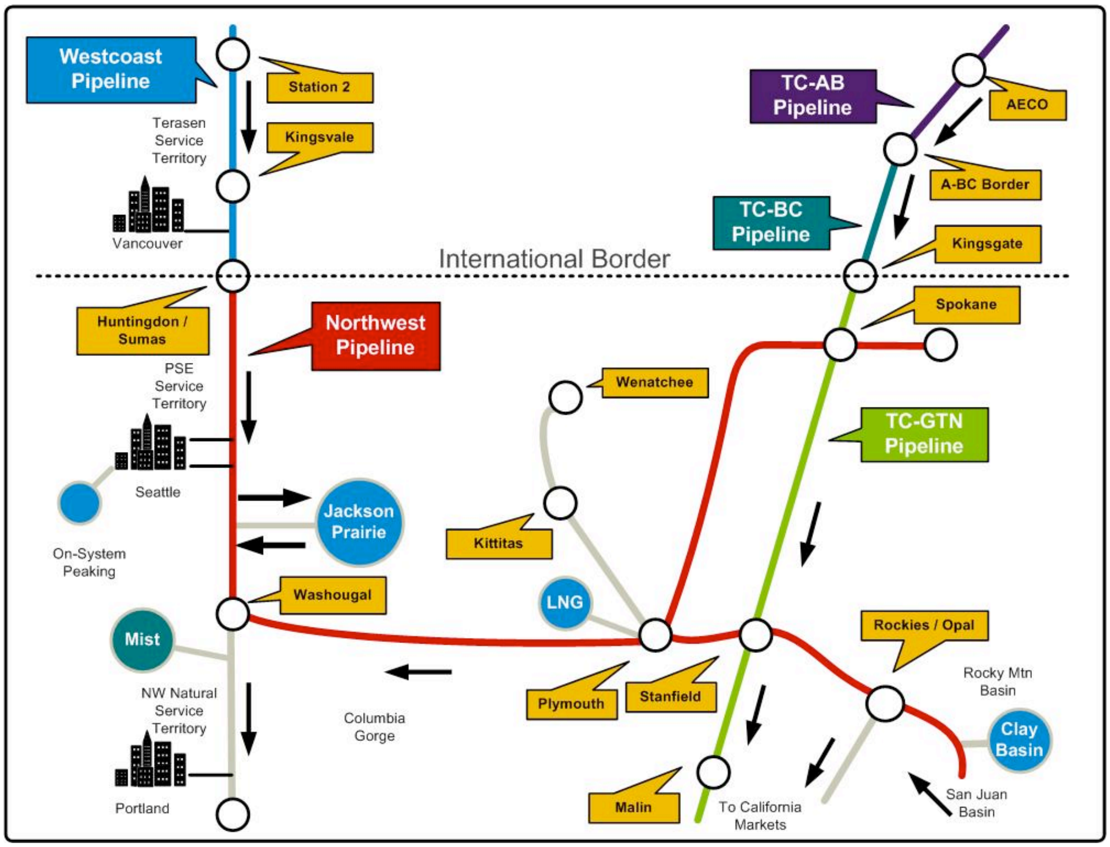


Figure 6-7 summarizes our direct-connect and upstream pipeline capacity position.

Figure 6-7
Gas Sales Pipeline Capacity (Dth/Day)

Pipeline/Receipt Point	Note	Total	Year of Expiration 2011	2013	2014	Other
Direct Connect						
NWP/Westcoast Interconnect (Sumas)	1	259,761	-	108,830	77,875	18,056 (2016) 55,000 (2018)
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	-	75,936	
NWP/various Rockies	1	184,356	616	47,400	126,436	8,056 (2016) 1,848 (2018)
Total TF-1		520,053	616	156,230	280,247	82,960
NWP/Jackson Prairie	1,2	110,704	-	-	-	110,704 (2028)
NWP/Jackson Prairie	1,2	343,057	343,057	-	-	
NWP/Plymouth LNG	1,2	70,500	70,500	-	-	
Total TF-2/Special TF-1		524,261	413,557	-	-	110,704
Total Capacity to City Gate		**1,044,314**	**414,173**	**156,230**	**280,247**	**193,664**
Upstream Capacity						
TC-Alberta/from AECO to TC-BC Interconnect (A-BC Border)	3	79,744	79,744			
TC-BC/from TC-Alberta to TC-GTN Interconnect (Kingsgate)	4	78,631	70,604			8,027 (2023)
TC-GTN/from TC-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	-	-	65,392 (2023)
TC-GTN/from TC-BC Interconnect to NWP Interconnect (Stanfield)	5,6	25,000	-	-	-	25,000 (2023)
Westcoast/from Station 2 to NWP Interconnect (Sumas)	4,7	95,000	-	-	-	25,000 (2014) 55,000 (2018) 15,000 (2019)
Total Upstream Capacity	**8**	**345,392**				

Notes:
1) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
2) *TF-2 and special TF-1 service is intended only for delivery of storage volumes during the winter heating season; these annual costs are significantly lower than year-round TF-1 service.*
3) *Converted to approximate Dth per day from contract stated in gigajoules per day.*
4) *Converted to approximate Dth per day from contract stated in cubic meters per day.*
5) *TCPL-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.*
6) *Capacity can alternatively be used to deliver additional volumes to Spokane.*
7) *The Westcoast contracts contain a right of first refusal upon expiration.*
8) *Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for some supplies available at Sumas.*

Firm and Interruptible Capacity. Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points in accordance with the pipeline's published tariff. Tariffs define the scope of service and are approved by the Federal Energy Regulatory Commission (FERC) in the United States, or the National Energy Board in Canada. The scope of service includes the number of days that the transportation service is available, along with the rates, rate adjustment procedures, and other operating terms and conditions. Firm transportation capacity requires a fixed payment, whether or not that capacity is used.

Firm capacity on NWP and TC-GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. Firm capacity on Westcoast can also be remarketed under recently instituted "streamlined capacity assignment" provisions. PSE aggressively releases capacity when we have a surplus and when market conditions make such transactions favorable for customers. The company also uses the capacity release market to access additional firm capacity when it is available.

Interruptible service is subordinate to the rights of shippers who hold and use firm transportation capacity; when firm shippers do not use their pipeline capacity, they may release it for limited periods of time. Interruptible service is available to PSE from NWP under TI-1 rate schedules, but because it cannot be relied on to meet peak demand, it plays a limited role in PSE's resource portfolio. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Existing Storage Resources

PSE's natural gas storage capacity is a significant component of the company's gas resource portfolio. It confers advantages that improve system flexibility and create significant cost savings for both the system and customers.

- Ready access to an immediate and controllable source of firm gas supply enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to a pooling point makes it possible for the company to store gas that was purchased but not consumed during off-peak seasons, and to buy additional gas during the lower-demand summer season at significant cost savings.
- Combining storage capacity with seasonal TF-2 (or special winter-only TF-1) transportation allows us to eliminate the need to contract for year-round pipeline capacity to meet winter-only demand.

PSE also uses storage to balance city-gate gas receipts with the actual loads of our gas transportation customers. Industrial and commercial customers who elect gas transportation service (rather than gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to their respective meters. When these customers or marketers have imbalances between scheduled and actual gas consumption, PSE's storage capacity allows us to manage these imbalances on a daily basis.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie storage, in Lewis County, is an aquifer-driven storage field designed to deliver large quantities of gas over a relatively short period of time. Clay Basin in northeastern Utah provides supply-area storage and a winter gas supply. Figure 6-8 presents details about storage capacity.

Figure 6-8
Gas Sales Storage Resources

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned (1)	7,713,040	147,334	398,667	N/A
Jackson Prairie – Owned (2)	(500,000)	(25,000)	(50,000)	2010
Jackson Prairie – NWP SGS-2F (3)	1,181,021	24,195	48,390	2011
Jackson Prairie – NWP SGS-2F (4)	140,622	3,352	6,704	2009
Clay Basin	13,419,000	55,900	111,825	2013/19
Total	**21,953,683**		**515,586**	

Notes:
1) *Storage capacity at 12/31/2008. Storage capacity at this facility will continue to grow through 2011.*
2) *A portion of PSE's Jackson Prairie capacity has been made available for electric generation needs through March 31, 2010.*
3) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
4) *Obtained through capacity release market, negotiations for an extension are under way.*

Jackson Prairie Storage. PSE uses Jackson Prairie and the associated NWP TF-2 and Special TF-1 transportation capacity primarily to meet the intermediate peaking requirements of core customers—that is, to meet seasonal load requirements, balance daily load, and eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. As shown in Figure 6-8, we have 453,761 Dth per day of TF-2 and special winter-only TF-1 transportation capacity from Jackson Prairie.

PSE, NWP, and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, operated by PSE under FERC authorizations. In addition to firm daily deliverability and firm seasonal capacity, we have access to deliverability and seasonal capacity through a contract for SGS-2F storage service from NWP and from a third party through the capacity release market. The NWP contract is automatically renewed each year but we have the unilateral right to terminate the agreement with one year's notice. We have interruptible withdrawal rights of up to 58,000 Dth per day, plus interruptible transportation service.

To meet growing peaking requirements, the three owners of Jackson Prairie recently increased the deliverability from 884,000 Dth per day to 1,196,000 Dth per day. Our share of this expansion (104,000 Dth per day) entered service in November 2008. We will continue to expand the Jackson Prairie Storage reservoir through about 2011.

Clay Basin Storage. Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 13,419,000 Dth and withdraw up to 111,825 Dth per day under a FERC-regulated agreement.

We use Clay Basin as a pooling point for purchased gas, and as a partial supply backup in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. This supply provides a reliable source throughout the winter, including on-peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (and other markets) using firm TF-1 transportation.

Treatment of Storage Cost. Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through a purchased gas adjustment (PGA), while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base rates. PSE pays a variable charge for gas injected into and withdrawn from Clay Basin.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. Liquefied natural gas (LNG) storage, LNG satellite storage, vaporized propane-air (LP-Air) and a peak gas supply service (PGSS) provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these sources typically meet extreme peak demand during the coldest hours or days. LNG, PGSS, and LP-Air do not offer the flexibility of other supply sources.

Figure 6-9
Gas Sales Peaking Resources

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Transport Tariff
Plymouth LNG	241,700	1,208	70,500	TF-2
Gig Harbor LNG (1)	5,250 10,500 (06-07) 15,750 (10-11)	1,500 3,000 (06-07)	2,000 3,000 (06-07) 4,000 (08-09) 5,250 (10-11)	On-system
Swarr LP-Air	128,440	16,680 (2)	10,000	On-system
PGSS	NA	NA	48,000	City-gate delivered, via TF-1 or commercial arrangement
Total	**375,390**	**19,388**	**131,500**	

Notes:
1) *Withdrawal capacity will grow as the load on the distribution system grows, allowing more supply to be absorbed.*
2) *Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.*

Plymouth LNG. NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. PSE's long-term contract provides for seasonal storage with an annual contract quantity (ACQ) of 241,700 Dth, liquefaction with an MDQ of 1,208 Dth per day, and a withdrawal MDQ of 70,500 Dth per day. The ratio of injection and withdrawal rates means that it can take more than 200 days to fill to capacity, but only 3-1/2 days to empty. Therefore, we use LS-1 service to meet needle-peak demands, with LS-1 gas delivered to PSE's city gate using firm TF-2 transportation.

Gig Harbor LNG. In the Gig Harbor area, a new satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of our distribution system. The facility receives, stores, and vaporizes LNG that has been liquefied at other LNG facilities; the LNG comes by tanker truck from third-party providers. Because the LNG source is outside PSE's distribution system, this facility represents an incremental supply source and is therefore included in the peak day resource stack, even though the plant was justified based on distribution capacity need. Daily deliverability is limited by hourly deliverability, total storage capacity, and the ability of the distribution system to absorb the supply. Although this facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

A second tank, substantially completed in the fall of 2006, doubled on-site storage capacity and increased operational flexibility (one tank can be filled while the other is used). Space has been allocated for a third tank, but no installation date has been projected. It will cost substantially more than the second tank because of additional site preparation requirements, so any expansion decision will be based on distribution capacity need rather than supply need.

Swarr LP-Air. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth equivalent, and can vaporize approximately 30,000 Dth per day – a little more than four days of supply at maximum capacity. Swarr connects to PSE's distribution system, requiring no upstream pipeline capacity. It is typically used to meet extreme hourly or daily peak demand, or to supplement distribution pressures during pressure declines on NWP. PSE operates this facility to meet peak early morning and evening demand periods; given its operational flow characteristics, it is highly unlikely the company will operate it for more than eight hours per day. Therefore, for peak-day planning purposes, we consider this facility capable of supplying only 10,000 Dth per day.

Third-party Suppliers. Under our PGSS agreements, PSE can call on third-party gas supplies during peak periods for up to 12 days during the winter season. Currently, these amount to 48,000 Dth per day at a price tied to the replacement cost of distillate oil. The supply would be delivered to PSE city gates from Sumas on a firm basis through TF-1 capacity (when such capacity is not needed for other supplies) or by a commercial best-efforts exchange agreement with a third party. The PGSS agreement expires after the 2011-2012 heating season, and renewal options appear unlikely at this time.

Existing Gas Supplies

Within the limits of this transportation and storage network, PSE maintains a policy of sourcing gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability; if a supplier defaults, PSE can source gas from another place along the pipeline. We can also mitigate price volatility somewhat; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin. While the majority of PSE's current supplies come from northern British Colombia in Canada, we also maintain pipeline capacity access to producing regions in the Rockies and San Juan, and Alberta.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may “separate” due to pipeline capacity shortages. This separation cycle can last one to three years and is alleviated when additional pipeline infrastructure is constructed. We expect generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation.

We have always purchased our supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal; but alternate points, such as gathering system interconnects with NWP, allow some purchases directly from producers as well as from gathering and processing firms. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply at or close to the wellhead, or point of production. Adding upstream pipeline transportation capacity on Westcoast, TC-AB, and TC-BC to the company’s portfolio has increased our ability to access supply at the wellhead in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term and medium-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. We also contract for seasonal baseload firm supply, typically for the winter months. Forward-month transactions supplement baseload transactions, particularly for November through March; we estimate average load requirements for upcoming months and enter into month-long transactions to balance load. PSE balances daily positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. Because our markets are liquid, long-term contracts do not offer significant advantages (other than reliability) at this time. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contract policies.

Like many local distribution companies (LDCs), PSE is somewhat at a buying disadvantage because of our very low load-factor market compared to industrial and power-generation markets, which may make access to additional supply more difficult over time. Our general policy is to maintain firm supply commitments equal to approximately 50% of expected seasonal demand, including assumed storage injections in summer and net of assumed storage withdrawals in winter.

Figure 6-10 summarizes PSE's long-term gas contracts as of March 2009. Termination dates are spread out over a number of years. The company will renew, extend, or replace contracts as they expire.

Biogas Supplies

PSE has purchased biogas from King County's wastewater treatment plant in Renton, Wash. since 1985 (see Contract 1 in Figure 6-10).

Recently, we joined with King County and Bio-Energy-Washington to use methane gas produced at the Cedar Hills Regional Landfill to fuel PSE's gas-fired generating plants. The gas will be transported to NWP (which is adjacent to the landfill) and from there to the generating plants. Cedar Hills is expected to supply an average of approximately 5.5 MDth per day of methane.

Figure 6-10
Gas Sales Long-term Supply Contracts

Contract	Basin	Summer Volume (Dth/d)	Winter Volume (Dth/d)	Primary Term Start Date	Primary Term Termination Date
Core Gas					
Contract 1	System	750	750	05/15/1985	
Contract 2	BC/Sumas	20,000	20,000	11/01/2004	10/31/2009
Contract 3	BC/Sumas	10,000	10,000	11/01/2004	10/31/2009
Contract 4	BC/Sumas	10,000	10,000	11/01/2004	10/31/2009
Contract 5	BC/Sumas	0	10,000	11/01/2007	03/31/2010
Contract 9	BC/Sumas	0	10,000	10/01/2007	04/30/2010
Contract 6	BC/Stn 2	0	10,000	10/01/2007	04/30/2010
Contract 7	BC/Stn 2	0	10,000	10/01/2007	04/30/2010
Contract 8	BC/Stn 2	0	10,000	10/01/2007	04/01/2010
Contract 9	BC/Stn 2	0	10,000	11/01/2009	03/31/2012
Contract 10	BC/Stn 2	0	10,000	11/01/2009	11/01/2012
Subtotal	**BC**	**40,000**	**110,000**		
Contract 12	Alberta	10,000	10,000	11/01/2004	10/31/2009
Contract 13	Alberta	10,000	10,000	11/01/2008	11/01/2009
Contract 14	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 15	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 16	Alberta	0	10,000	02/01/2007	04/30/2010
Contract 17	Alberta	0	10,000	10/01/2009	05/01/2011
Subtotal	**Alberta**	**20,000**	**60,000**		
Contract 18	Rockies	20,000	20,000	11/01/2004	10/31/2014
Contract 19	Rockies	10,000	10,000	04/01/2005	10/31/2009
Contract 20	Rockies	10,000	10,000	04/01/2005	03/31/2010
Contract 21	Rockies	30,000	30,000	04/01/2008	03/31/2013
Contract 22	Rockies	10,000	10,000	05/01/2008	05/01/2009
Contract 23	Rockies	0	10,000	11/01/2004	03/31/2014
Contract 24	Rockies	0	10,000	10/01/2006	04/30/2010
Contract 25	Rockies	0	10,000	10/01/2006	04/30/2010
Subtotal	**Rockies**	**80,000**	**110,000**		
Electric					
Contract 26	Alberta	10,000	0	7/1/2010	10/1/2012
Total		**150,750**	**280,750**		

B. Demand-side Resources, Gas Sales

PSE has provided demand-side resources (that is, resources generated on the customer side of the meter) since 1993. Energy efficiency measures installed through 2007 have saved a cumulative total of 1.9 million Dth – more than half of which has been achieved since 2002. Through 1998, these programs primarily served residential and low-income customers. In

1999 the company expanded to add commercial and industrial customer facilities. PSE has spent more than $31 million for natural gas conservation programs from 1997 to 2007. PSE's energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of our 2001 General Rate Case.

Our energy efficiency programs serve all types of customers—residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2006-2007 biennial program period concluded at the end of 2007; current programs operate January 1, 2008 through December 31, 2009. The majority of gas energy efficiency programs are funded using gas "tracker" funds collected from all customers.

For the 2008-2009 period, a two-year target of approximately 530,000 Dth in energy savings has been adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

Current Gas Energy Efficiency Programs

2007 marked the conclusion of a 2-year conservation tariff period. Figure 6-11 shows performance compared to two-year budget and savings goals for the biennial 2006-2007 electric energy efficiency programs, and records 2008 progress against 2008-2009 budget and savings goals.

During 2006-2007, the programs saved a total of 504,172 Dth at a cost of $14.5 million. This exceeded the two-year goal of 445,612 Dth, and represented enough gas to supply 7,500 homes. In 2008, savings have already reached 69% of the two-year goal at 367,000 Dth, on expenditures of $12.6 million (or 50% of the two-year budget). 2006-2007 results include one-time savings of approximately 750,000 therms from continuation of a program to replace commercial spray heads (the program contributed 2 million therms to 2004-2005 savings). Savings from this program are not repeatable, but PSE continues to seek projects of such magnitude through internal channels and the RFP process. After considering the effect of the spray head program on savings achievement in 2006-2007, our 2008 levels track in alignment with our previous accomplishments.

Figure 6-11
Gas Sales Energy Efficiency Program Summary

Tariff Programs	2006- 2007 Actuals	'06–'07 Budget/ Goal	'06 vs. '06/07 % Total	2008 Actual	'08 –'09 2- Year Budget/ Goal	'08 vs. '08/'09 % Total
Gas Program Costs*	$14,497,432	$12,595,460	44.8%	$12,630,383	$25,268,000	50.0%
Dth Savings	504,172	445,613	47.2%	367,230	530,000	69.3%

** Does not include low-income weatherization O&M funding of $297,000 per year.*

PSE's **Commercial/Industrial Retrofit Program** is a custom incentive program that achieves energy savings through improvements to HVAC systems, boilers, and process gas modifications such as efficiency gains in radiator steam trap systems. In 2008, these efforts produced savings of 2.3 million therms at a cost of $3.6 million, and this program was the largest generator of gas sales energy efficiency savings.

The **Gas Weatherization** program generated the most energy efficiency savings on the residential side. A variety of insulation measures (among them wall, floor, and ceiling insulation, as well as duct sealing) and other gas conservation measures were eligible for rebates; the program saved 500,000 therms at a cost of $2.8 million, and accounted for 14% of all gas sales energy efficiency savings in 2008.

RFPs. Two RFPs were issued for gas sales energy efficiency resources to be added during the 2008-2009 program cycle. The first, issued in June 2007, targeted specific energy efficiency markets. The second, issued in January 2008, was an "all-source" RFP. The RFP process is used to seek out and fill untapped market segments or add under-utilized energy efficiency technologies to complement ongoing efforts. No significant new opportunities were identified as a result of this RFP process.

C. Supply-side Resources, Electric Generation

Figure 6-12 summarizes the firm pipeline transportation capacity for delivery of fuel to PSE's gas-fired generation plants.

Figure 6-12
Power Generation Gas Pipeline Capacity (Dth/Day)

Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Direct-connect Capacity						
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2000	Yr. to Yr.
Tenaska	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2000	Yr. to Yr.
Encogen	Cascade Natural Gas	Firm	(1)	NWP (Bellingham) to Plant	2008	Yr. to Yr.
Fredonia	Cascade Natural Gas	Firm	(1)	NWP(Sedro-Wooley) to Plant	2021	Yr. to Yr.
Mint Farm	Cascade Natural Gas	Firm	(5)	NWP (Longview) to Plant	2011	Yr. to Yr.
Freddy 1	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr.
Goldendale	NWP	Firm	45,000	Westcoast (Sumas) to Everett (3)	2018	Yr. to Yr
Upstream Capacity						
Plant	**Transporter**	**Service**	**Capacity (Dth/day)**	**Primary Path**	**Year of Expiration**	**Renewal Right**
Various	Westcoast	Firm	21,794	Station 2 to Sumas	2014	Yes
Various	Westcoast	Firm	25,461	Station 2 to Sumas	2018	Yes
Various	NWP	Firm (4)	16,884	Rockies to Bellingham	2011	No
Various	NWP	Firm (4)	6,600	Sumas to Bellingham	2011	No
Mint Farm & Various	NWP	Firm	10,710	Sumas to Stanfield	2044	Yes
Mint Farm & Various	NWP	Firm	500	Sumas to Longview	2044	Yes
Mint Farm & Various	NWP	Firm	9,000	Sumas to Longview	2015	No
Storage Capacity						
Plant	**Transporter**	**Service**	**Deliverability (Dth/day)**	**Storage Capacity (Dth)**	**Year of Expiration**	**Renewal Right**
Jackson Prairie	PSE	Firm	50,000	500,000	2010	No

Notes
1. *(1) Plant requirements.*
2. *(2) Converted to approximate Dth/day from contract stated in cubic meters /day.*
3. *(3) Gas transported from Everett to Goldendale under NWP flex rights, backed by displacement agreement with PSE's gas sales portfolio.*
4. *(4) Capacity held by third party, controlled by PSE under grandfathered agreement.*
5. *(5) Firm for approximately ½ plant requirements, remainder interruptible. PSE is in the process of securing additional firm capacity and extending term.*
6. *(6) Storage capacity made available (for market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs.*

PSE has firm upstream pipeline capacity to serve our combined-cycle generating plants (Freddy1, Goldendale and Mint Farm). Several of our combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have backup fuel-oil firing capability and thus do not require firm pipeline capacity. The Tenaska generating facility also has backup fuel-oil firing capability.

III. Gas Resource Alternatives

The gas resource alternatives presented in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in our daily conduct of business to minimize costs. They also include consideration of the increasing need to diversify gas supplies explained in the first section of this chapter.

Diversity of Supply Considerations

Direct-connect pipelines. PSE's exclusive reliance on NWP to connect to upstream natural gas supplies is a matter of geography, not preference. Until recently potential sponsors have shown little interest in the construction of new pipelines because of high construction costs and limited need. New construction cannot compete financially with the inherently lower cost of expanding or rebuilding infrastructure in an existing right-of-way.

Because PSE retains the unilateral right to cancel NWP contracts upon one year's notice, pending contract expirations in 2013, 2014, 2016, and 2018 create opportunities to make alternative resource decisions; however, maintaining current NWP capacity at "vintage" rates will most certainly be the company's most cost-effective alternative. To accommodate growth, future expansions of NWP between Sumas and PSE's city gate, in combination with acquiring uncontracted Westcoast capacity between Sumas and Station 2, likely will be the next most cost-effective alternative. Currently, approximately 20% of the Westcoast pipeline capacity to Sumas is not under long-term contract.

However, while expansion of the NWP segment between Sumas and PSE's city gate is probably the lowest-cost alternative for increased access to any market hub, the decision to expand access to the Sumas or Station 2 hubs would have to be balanced with the risks of further increasing the portfolio's reliance on British Columbia (or any WCSB) sourced supplies.

Gas Supplies. There have been reports of significant discoveries of shale gas supplies in northeast British Columbia. While the high cost of shale gas development in a remote area of British Columbia, coupled with the lack of infrastructure will delay development, this would appear to provide additional supplies at Station 2 and Sumas. Westcoast open season results suggest that as much as 300 MDth per day of incremental supply may be available for bidding by PSE and others at Station 2. However, the apparent success of the Nova Gas Transmission Limited (TC-AB) open seasons might also suggest that the vast majority of new

British Columbia shale supplies are intended for the Alberta market and committed to a pipeline route that completely bypasses the Westcoast system, making it impossible for PSE to even bid to acquire the gas.

While increased supplies from British Columbia (and eventually Alaska and Mackenzie) may be available into the AECO market, a significant decline in net export supplies is forecast. Substantial increases in demand within Alberta, primarily due to fuel oil sands production, are forecast to more than offset the increased supplies.

Recent development of conventional resources as well as the expected development of shale and tight formations based on new horizontal drilling and fracturing technologies have resulted in an increase in production in the Rocky Mountain region. Between 2007 and 2030, Global Insight forecasts a 22% increase in Rocky Mountain production. Gas production increases in the Rocky Mountain region have resulted in Rockies forward market prices (Opal Hub) that are significantly lower than both Sumas and AECO Hub prices.

Figure 6-13
Forward Market Supply Hub Prices and Basis Differentials 2010 - 2013
($/MMBtu)

	Sumas	Rockies	AECO	Sumas - Rockies Basis Diff.	AECO - Rockies Basis Diff.
2010 - Q1	7.40	5.66	6.40	1.74	0.74
Q2	5.94	4.12	5.89	1.82	1.77
Q3	6.24	4.31	6.12	1.93	1.81
Q4	7.43	5.28	6.59	2.15	1.31
2011 - Q1	7.97	6.09	7.05	1.88	0.96
Q2	6.19	4.66	6.19	1.52	1.53
Q3	6.44	4.78	6.35	1.66	1.57
Q4	7.66	5.64	6.75	2.02	1.11
2012 - Q1	8.14	6.43	7.14	1.71	0.71
Q2	6.22	5.29	6.23	0.92	0.93
Q3	6.48	5.42	6.38	1.05	0.95
Q4	7.75	6.09	6.77	1.66	0.68
2013 - Q1	7.93	6.88	7.16	1.04	0.28
Q2	6.36	5.54	6.23	0.81	0.69
Q3	6.61	5.68	6.38	0.93	0.70
Q4	7.90	6.27	6.80	1.63	0.53
			4 year average =	**1.53**	**1.02**
			Minimum =	**0.81**	**0.28**
			Maximum =	**2.15**	**1.81**

For example, as shown in Figure 6-13, the average forward market prices for Rockies gas during over the 2010-2013 period is $1.53 per MMBtu lower than Sumas prices, and $1.02 lower than AECO prices.

Pipeline expansion projects between the Rockies and PSE's service territory could be largely justified based solely on basis differentials if such differentials were guaranteed to continue over the 20-year planning period. However, long-term price forecasts do not show such large basis differentials continuing. Differentials are expected to decline as new pipelines are built to carry gas from the Rockies to markets, thereby balancing the supply and demand for Rockies gas. The irony is that unless the new pipelines are built, the price differential may continue to expand. Yet, if the pipelines are built, the price differential may shrink – but those connected to the pipeline will have access to the new source of gas and that access could serve to lower relative prices at alternate sources.

A Commercially Viable Route to the Rocky Mountain Basin. The proposed Ruby pipeline extending from the Rockies area to interconnect with the TC-GTN pipeline at Malin, Ore., will expand the availability of Rockies gas at Malin. This pipeline is currently scheduled to be completed in 2011.

To provide access to the increased supply of gas at Malin, PSE and other utilities are evaluating pipeline alternatives to transport gas between Malin and the I-5 corridor. PSE and NWP have jointly proposed the Blue Bridge expansion of the existing NWP system between Stanfield and the Puget Sound area. NW Natural and TransCanada have proposed the Palomar pipeline to expand the supply of gas to NW Natural from TransCanada's GTN pipeline. The Palomar pipeline (from TC-GTN's system in central Oregon to NW Natural's system near Molalla, Ore.) offers an alternative route through the Columbia Gorge, but would also require upgrades to the NWP system along the I-5 corridor in order to serve PSE. Further complicating the analysis is an expectation that the Palomar project would result in approximately 100,000 Dth per day of uncontracted capacity on the existing NWP system.

At this point it is unclear which of these pipeline proposals, if any, will be completed. For this IRP, an alternative with costs and capacity representative of the Blue Bridge and Palomar proposals is included in the analysis. This alternative, the Cross Cascades Pipeline, is shown in Figure 6-14 below.

Alternatives Considered

As shown earlier in Figures 6-3 and 6-4, the gas sales portfolio has sufficient resources through the winter of 2014-2015 (in the 2007 Base Case demand forecast); the need for additional resources to supply gas for electrical generation is more immediate, beginning in 2010.

Transporting gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct connect pipeline alternatives and storage options to create combinations that have different costs and benefits.

In this IRP, the alternatives have been gathered into five broad combinations for analyses. These combinations are illustrated in Figure 6-14.

- Combination #1 provides for an increased supply of Alberta (AECO hub) gas delivered via expanded upstream pipeline capacity on the TC-AB, TC-BC, and TC-GTN pipelines with final delivery to PSE via the Cross Cascades pipeline.

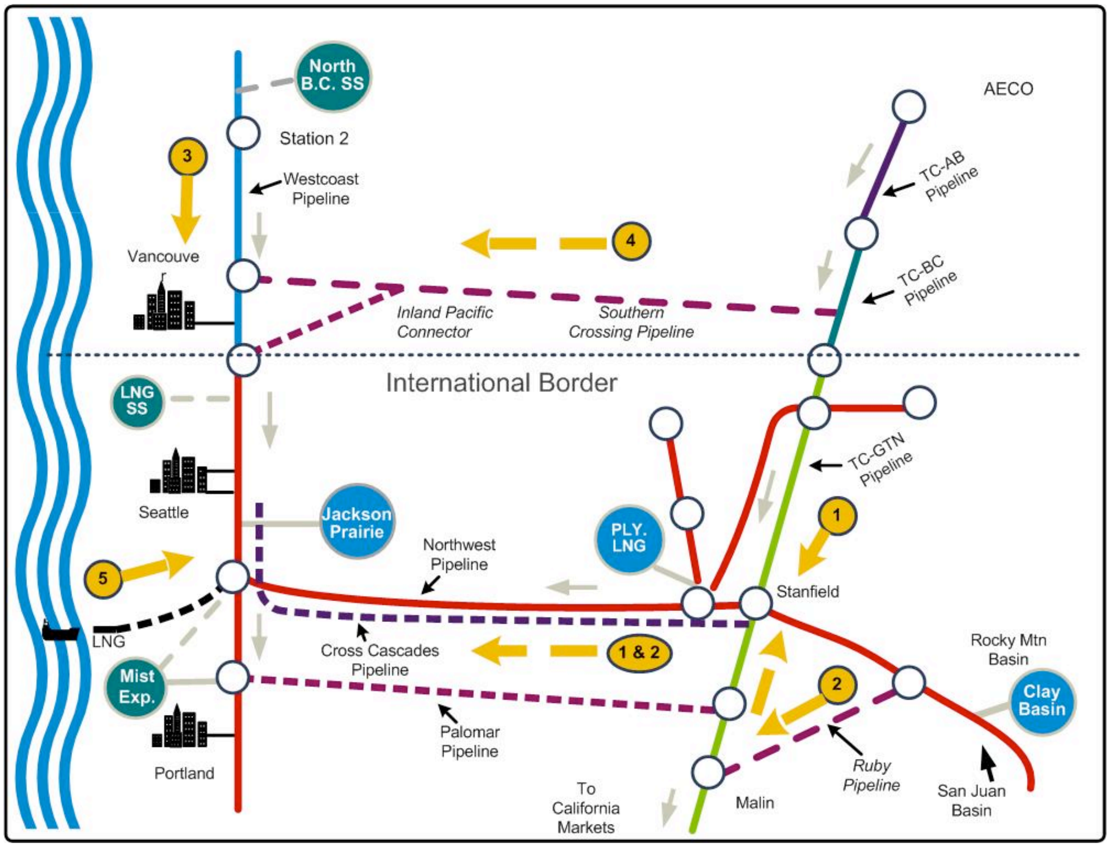
- Combination #2 provides for an increased supply of Rockies gas delivered to Malin on the Ruby pipeline, then on TC-GTN to the Cross Cascades pipeline.

- Combination #3 illustrates the option of expanding access to northern British Columbia gas (Station 2 hub) with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area.

- Combination #4 represents the Southern Crossing pipeline option. This option would allow delivery of AECO gas to PSE via expanded capacity on the TC-AB and TC-BC pipelines, an expanded Southern Crossing pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

- Combination #5 provides delivery of gas imported at an LNG import terminal located near the lower Columbia River. Delivery of gas would require construction of a pipeline between the terminal and NWP as well as the expansion of NWP to PSE's service area.

Figure 6-14
PSE Gas Transportation Map Showing Supply Alternatives



In addition to the five primary pipeline combinations, Figure 6-14 shows the three gas storage alternatives included in the analysis.

A. Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 6-15 below.

Figure 6-15
Direct-connect Pipeline Alternatives Analyzed

Name	Description
NWP - Sumas to PSE city gate	Expansions considered only in conjunction with upstream pipeline/supply expansion alternatives (Southern Crossing or additional Westcoast capacity).
Cross Cascades – Stanfield/TC-GTN to PSE city gate	Representative of costs and capacity of either the proposed Blue Bridge expansion of NWP or the Palomar pipeline with delivery on NWP to PSE city gate.
NWP - Washougal to PSE city gate	Expansion considered in conjunction with a Columbia River LNG import terminal or expansion of the Mist storage facility.

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying gas at one point, and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with our supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast Pipeline, which allows us to purchase gas at Station 2 rather than Sumas allowing us to take advantage of the greater supplies available at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable us to purchase gas directly from suppliers at the very liquid AECO trading hub and transport it to interconnect with the Southern Crossing or Cross Cascades pipelines on a firm basis.

Figure 6-16
Upstream Pipeline Alternatives Analyzed

Name	Description
Increase Westcoast Capacity (Station 2 to Sumas)	Acquisition of currently uncontracted Westcoast capacity is considered to increase access to gas supply at Station 2 and a northern B.C. storage alternative for delivery to PSE on expanded NWP capacity from Sumas.
TransCanada Pipeline Expansion (AECO to Stanfield)	Expansion of TransCanada pipeline capacity in Canada (TC-AB & TC-BC) and acquisition of currently uncontracted capacity on TC-GTN to increase deliveries of AECO gas to Stanfield for delivery to PSE city gate via the Cross Cascades pipeline.
Southern Crossing Pipeline	Expansion of the existing Terasen gas pipeline across southern B,C., a new lateral connecting to Huntingdon B.C, (Sumas), plus a commensurate expansion of the capacity on TC-AB and TC-BC for delivery to PSE on expanded NWP capacity from Sumas.

The Southern Crossing alternative includes (1) PSE participation in the existing (or an expansion of the existing) Terasen pipeline across southern British Columbia, and (2) a new connector pipeline connecting this pipeline to Huntingdon, B.C. (Sumas), completely bypassing Westcoast facilities upstream of Sumas. Acquisition of this capacity, as well as additional capacity on the TCPL-Alberta and TCPL-BC lines, would improve access to the AECO trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply.

PSE currently has access to gas sourced at AECO via three layers of TransCanada pipeline to Stanfield and then to the PSE city gate via NWP. The addition of the Cross Cascades pipeline in conjunction with the acquisition of additional capacity on these pipelines would increase access to AECO gas and increase supply diversity.

B. Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie storage facility, and contracts for capacity at the Clay Basin storage facility located in northeastern Utah. At this time, however, neither offers PSE the possibility of expanding capacity beyond existing arrangements. For this IRP, the company considered the following storage alternatives:

The owner and operator of the Mist underground storage facility near Portland, Ore., is investigating potential expansion projects. PSE is assessing the cost-effectiveness of such possibilities; however, Mist expansions are also expected to have relatively high costs and limited firm access to PSE's city gate.

Participation in a regional LNG storage facility is also being considered. PSE's evaluation assumes costs and operating characteristics similar to the Mount Haynes LNG storage project currently under construction on Vancouver Island by Terasen Gas. LNG storage projects offer "needle peaking" capability; i.e. delivery of stored gas over a relatively short period of time (this analysis assumes approximately 10 days).

Contracting for storage service at the Aitken Creek storage facility in northern British Columbia is the final alternative under consideration. The Aitken Creek facility is similar to the Clay Basin storage project in that it offers "seasonal" storage; however, Clay Basin has cost-based rates, while Aitken Creek has market-based rates; market-based rates often erase a sizable portion of the savings potential that makes seasonal storage attractive.

Figure 6-17
Storage Alternatives Analyzed

Name	Description
Northern B.C. Storage Service	Based on estimated market price of existing Aitken Creek services.
Expansion of Mist Storage Facility	Based on estimated cost and operational characteristics of expanded Mist storage.
Regional LNG Storage Facility	To be cost effective, such a facility should be located to allow firm exchange delivery to PSE's city gate. The returns to scale of LNG storage imply that joint participation would be attractive. These analyses assume a 10-day supply at full deliverability.

C. Gas Supply Alternatives

As described earlier, gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin (our preferred alternative). Appendix K, Long-term Fundamental Gas Market Overview, contains a detailed discussion of future gas supplies.

Major pipeline projects have been proposed to transport gas from the Arctic to the North American markets, but these projects are too distant to provide short- or medium-term relief. The Alaska Natural Gas Transmission System would transport natural gas from the North Slope through Canada and to Chicago, and provide 4.5 Bcf per day starting between 2017 and 2019. The Mackenzie Valley Pipeline would transport natural gas from the Tablus, Parsons Lake, and Niglintgak fields to the northern border of Alberta and eventually deliver 800 Mcf per day.

Currently there are at least three proposals to construct LNG import terminals in the region. Two proposals, the Oregon LNG and the Bradwood Landing projects are located near the mouth of the Columbia River, while a third project, the Jordan Cove project is located at Coos Bay, Ore. Construction of an LNG import terminal could significantly increase the availability of gas in the region, depending on the commitment of suppliers to the terminal. At today's gas prices, LNG can be competitively transported, stored, and marketed. Many experts believe that significant LNG imports into North America will be required at some point in the future to balance supply and demand in the future—though few predict any of the import terminals will be located on the West Coast.

LNG production costs are within current and anticipated market prices. LNG projects typically have low exploration and technology risks, and very high capital costs. Projects generally require an experienced sponsor with a strong balance sheet, a secure source of natural gas, a large immediate market or an extensive infrastructure capable of consuming the entire output, and long-term off-take agreements to support the project's financing costs.

The market for LNG is worldwide and prices are typically based on world oil prices. Given the volatility of crude oil and natural gas prices over the past year, future LNG prices are uncertain. For purposes of this analysis, LNG import prices are based on the crude oil price forecasts from the same Global Insight long-term energy price forecasts as the natural gas prices. The Global Insight crude oil price forecasts tend to decline over the 2010-2029 time period, resulting in similarly declining LNG prices, while domestic natural gas prices are projected to increase over this period. In general, imported LNG becomes price competitive during the 2017-2022 period.

For this IRP, PSE assumed that supply may be available from an LNG import facility located on the mouth of the Columbia River beginning in 2017.

Figure 6-18
Gas Supply Alternatives Analyzed

Name	Description
LNG import facility located on lower Columbia River interconnected with NWP south of PSE service territory	Flows over NWP north to PSE on incremental transport capacity.
Conventional gas supply purchase contracts	Assume current mix of term contracts and spot purchases. Recent estimates of gas reserves indicate that supplies from the WCSB and Rockies will be sufficient to meet needs.

D. Demand-side Resource Alternatives

There were several steps in evaluating cost-effectiveness of demand-side resource measures.

Demand-side measures were first screened for technical potential. This step assumed that all opportunities could be captured regardless of cost or market barriers, so that the full spectrum of technologies, load impacts, and markets could be surveyed.

A second screen eliminated any resources not considered achievable. To gauge achievability, PSE relied on customer response to past PSE energy efficiency programs, and the experience of other utilities offering similar programs. For this IRP, the company assumed that 75% and 55% of gas demand-side resource potentials in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period.

The remaining measures are considered to have “achievable technical potential.” These measures were next combined into cost bundles and the bundles were arranged from lowest to highest cost (savings for all measures in each group were adjusted for interactive effects).

PSE currently seeks to acquire as much cost effective gas demand-side resource (DSR) as quickly as possible.
The acquisition rate, or "acceleration" rate, of gas DSR modeled in the IRP is consistent with this strategy and held static through the analysis. PSE, however, is interested in examining how it can overcome the obstacles that may allow it to change the acquisition rate at a future date. The primary obstacles currently faced are:

- Gas measures also are relatively long-lived, the replacement cycles tend to be longer, and there are a relatively higher proportion of "lost opportunity" measures. This means that a program that increases the acquisition rate would have to pay a premium to replace or install a measure before the useful life of an existing measure has ended, which limits the program's cost-effectiveness.
- Gas measures are costly. Even with utility incentives at the maximum avoided cost, the owner bares the major part of the project costs.
- There is no cost data available to reflect the higher cost of ramping measures, and hence the effect on cost effectiveness
- Gas measures typically require specialized knowledge to install, which means the necessity of hiring and managing a specialized contractor.

Finally, SENDOUT was used to test the optimal level of demand-side resources in each scenario. To format the inputs for SENDOUT analysis, the demand-side resource inputs consisting of the cost bundles were further sub-divided by market sector and weather/ nonweather sensitive measures. To determine the optimal demand-side resource, increasingly expensive bundles were added to each scenario until SENDOUT rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario.

Figure 6-19 illustrates the methodology described above.

Figure 6-20 shows the range of achievable technical potential among the seven cost bundles used in SENDOUT. It selects an optimal combination of each bundle for each market sector to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 6-21 shows a sample input format sub-divided by market sectors for Bundle AU (<$4.0 per Dth) used in the SENDOUT portfolio optimization model for all the bundles.

Figure 6-19
General Methodology for Assessing Demand-side Resource Potential

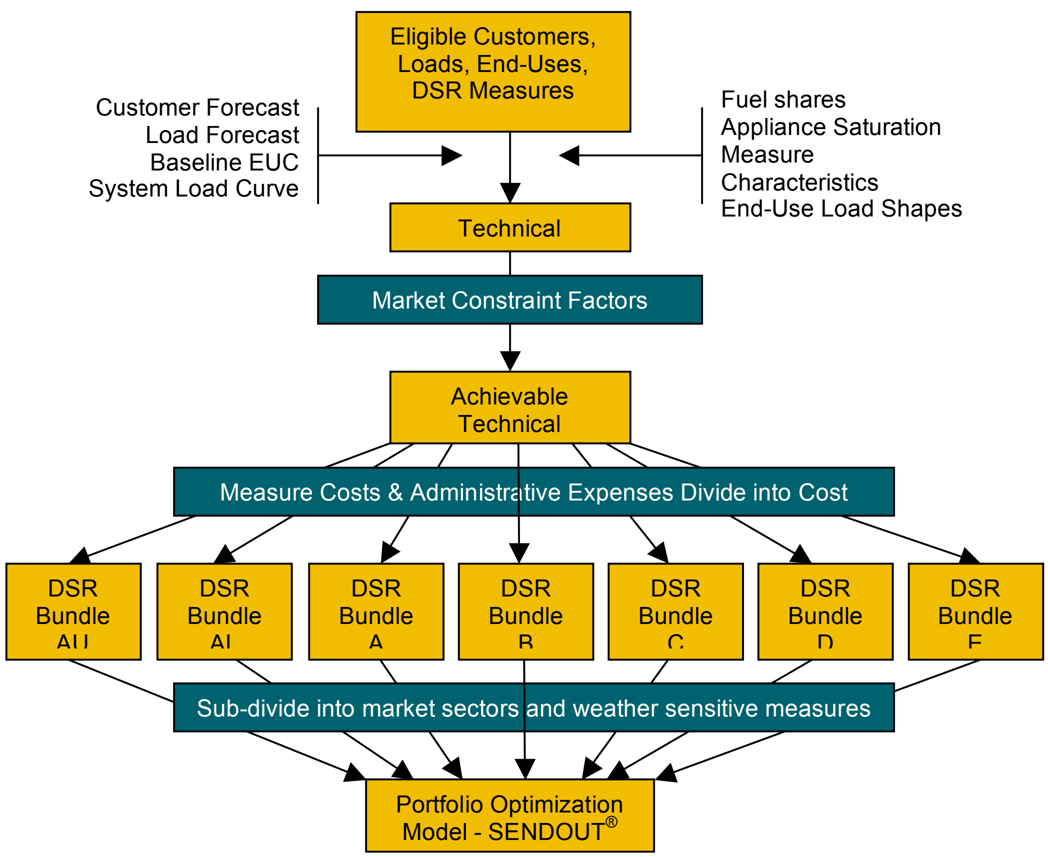


Figure 6-20
Achievable Technical Potential Bundles

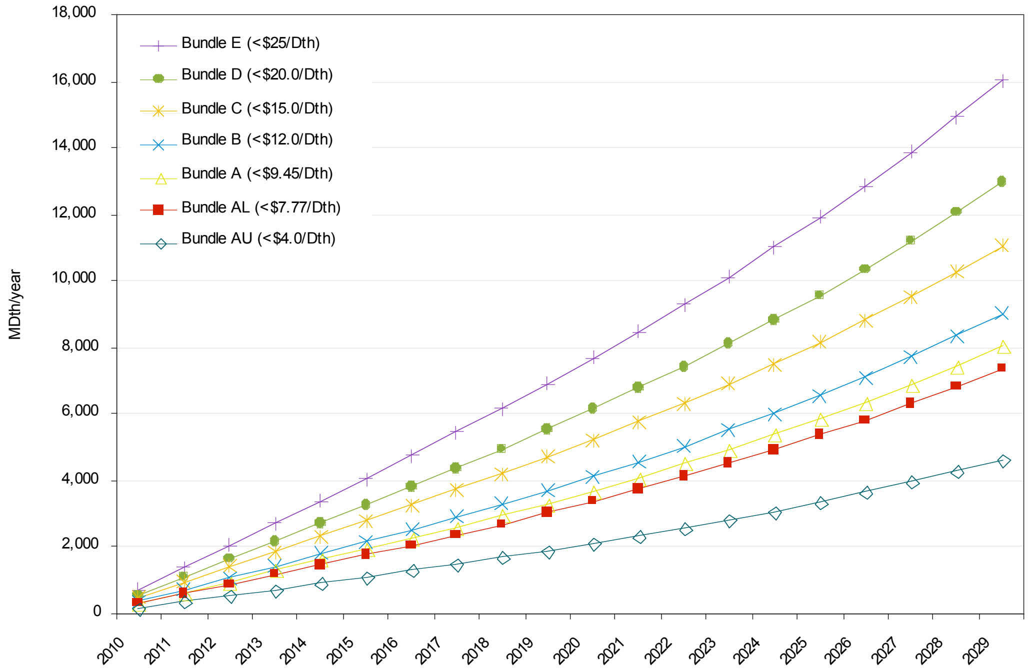
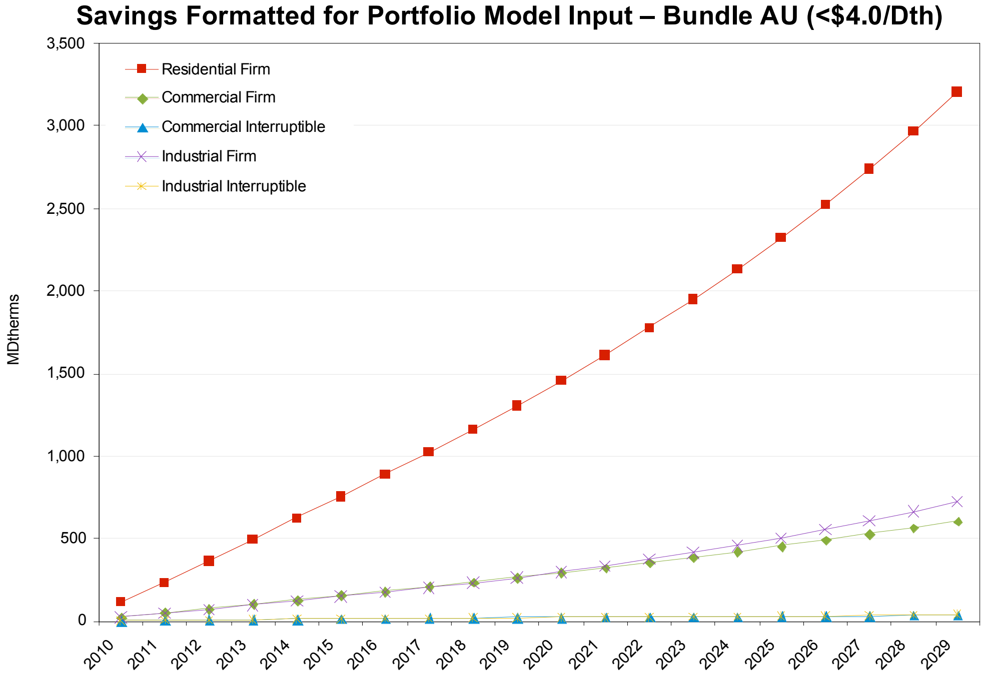


Figure 6-21
Savings Formatted for Portfolio Model Input – Bundle AU (<$4.0/Dth)



IV. Gas Analytic Methodology

In general, analysis of a gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing resources. Once need has been identified, a variety of planning tools, optimization analyses, and input assumptions help PSE identify the lowest-reasonable-cost portfolio of gas resources within a variety of scenarios. Demand forecasts are discussed in detail in Chapter 4. Scenarios and sensitivities are explained in Chapter 3. Here we describe three important analysis tools.

A. Optimization Analysis Tools

PSE uses SENDOUT, from Ventyx, to model gas resources for long-term planning and long-term gas resource acquisition activities. SENDOUT is widely used and employs a linear programming algorithm to help identify the long-term, least-cost combination of resources that will meet stated loads. SENDOUT also has the capability to integrate demand-side resources with supply-side resources to determine an optimal resource portfolio. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight," meaning that its theoretical results may not really be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. In the real world, numerous critical factors about the future will always be uncertain. Linear programming analysis can help inform decisions, but it should not be relied on to make them.

To incorporate uncertainty about future gas prices and weather-driven loads, PSE acquired the add-in product VectorGas to use with SENDOUT. In 2008, installation of SENDOUT Version 12.1.1 integrated VectorGas's Monte Carlo capability into SENDOUT itself. Monte Carlo analysis of physical supply risk indicates whether a portfolio that meets our design-day peak forecast is sufficient, in an otherwise normal-temperature winter, to meet our obligations under a variety of possible conditions. See Appendix J, Gas Analysis, for a more complete description of SENDOUT.

B. Deterministic Optimization Analysis

As described in Chapter 3, PSE developed seven gas sales scenarios to examine the impact of a range of possible future demand and price conditions on resource planning. Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions. Scenario analysis clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of future circumstances.

C. Monte Carlo Analysis

PSE performed two kinds of Monte Carlo analyses to test different dimensions of uncertainty. The first tested how well a single resource portfolio performs under gas price and load uncertainty over the 20-year planning horizon. For example, this approach can tell under what percentage of the Monte Carlo draws a specific resource portfolio meets design peak day loads.

The second application of the Monte Carlo analyses develops optimal resource portfolios in each of the 100 scenario draws. This approach can be used to generate probability distributions for each potential resource addition; i.e. in what percentage of the Monte Carlo draws is a specific resource added. A deterministic analysis often overemphasizes the importance of the "optimal" portfolio. This analysis showed how resource alternatives available in the 2007 Trends scenario are sensitive to the underlying price and demand assumptions.

PSE used Monte Carlo analyses to generate 100 daily price and temperature scenarios – or draws – for the 20-year planning horizon. For additional details of the SENDOUT analyses, see Appendix J, Gas Analysis.

V. Gas Analysis Results

For the gas sales portfolio, PSE analyzed seven scenarios and three sensitivities. For the combined portfolio (gas sales and gas for generation), two views were examined: one included a requirement for supply diversity, the other did not. Our purpose was to identify the costs associated with increasing diversity. Gas sales analysis results are presented first, then the combined portfolio results.

A. Gas Sales Portfolio Analysis and Results

Comparison of Resulting Average Annual Portfolio Costs

Figure 6-22 should be read with caution. Its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include rate-base costs related to Jackson Prairie storage and costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. It should also be noted that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 6-22
Cost Projections for Gas Scenarios & Sensitivity Analyses

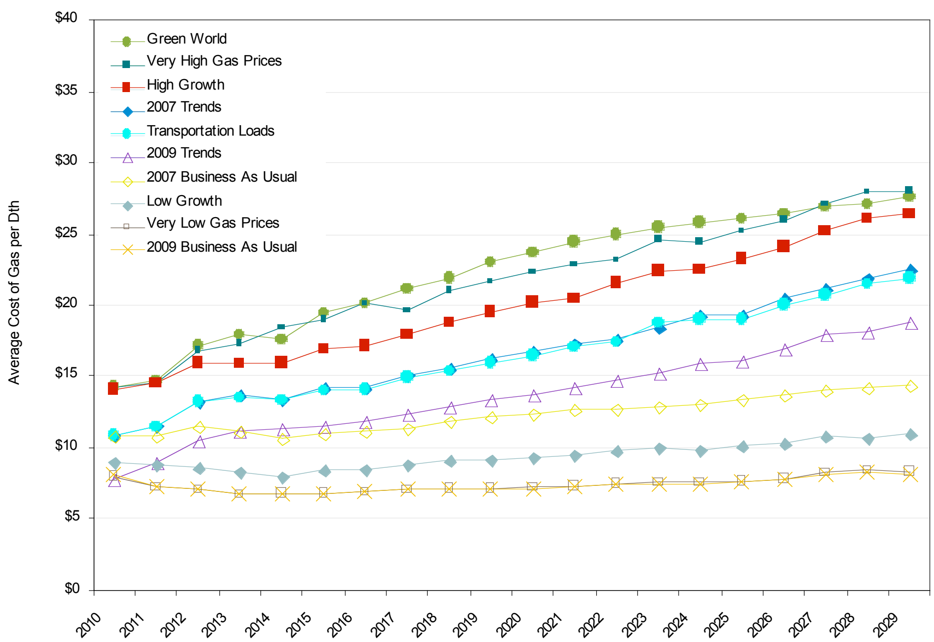


Figure 6-22 shows that average optimized portfolio costs are largely based on the gas and CO_2 cost assumptions included in each scenario.

- 2007 Trends scenario costs are about $10.90 per Dth in 2010 and increase to about $22.00 per Dth by 2029. 2007 Business as Usual costs also start at $10.90 per Dth, but rise to about $14.40 per Dth by 2029. The difference is due to CO_2 emissions costs (the only difference between the two scenarios).
- The Very Low Gas Price sensitivity and 2009 Business As Usual scenarios have the lowest portfolio prices; these reflect very low gas price assumptions and the absence of any CO_2 costs in either scenario.
- Green World costs are the highest, reflecting high CO_2 cost assumptions and a high gas price forecast.
- High Growth costs are somewhat lower, reflecting the lower CO_2 prices assumptions than Green World.

To test for Transportation Load sensitivity, the gas transportation load was included in the 2007 Trends scenario; its addition had little impact on the average cost of the portfolio. The Very High Gas Price sensitivity test also used 2007 Trends assumptions except for gas prices; this sensitivity significantly increased average portfolio costs. The Very Low Gas Price sensitivity was modeled using 2007 Business As Usual scenario assumptions except for gas prices.

Comparison of Resource Additions

Differences in resource additions are primarily driven by load growth and the gas and CO_2 price assumptions. Demand-side resources are influenced directly by gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature. However, the absolute level of efficiency programs is also affected by load growth assumptions.

The optimal portfolio resource additions in each of the seven scenarios and three sensitivity tests are illustrated in Figures 6-23 through 6-26 for 2015, 2020, 2025, and 2029 respectively.

Figure 6-23
Gas Resource Additions in 2015

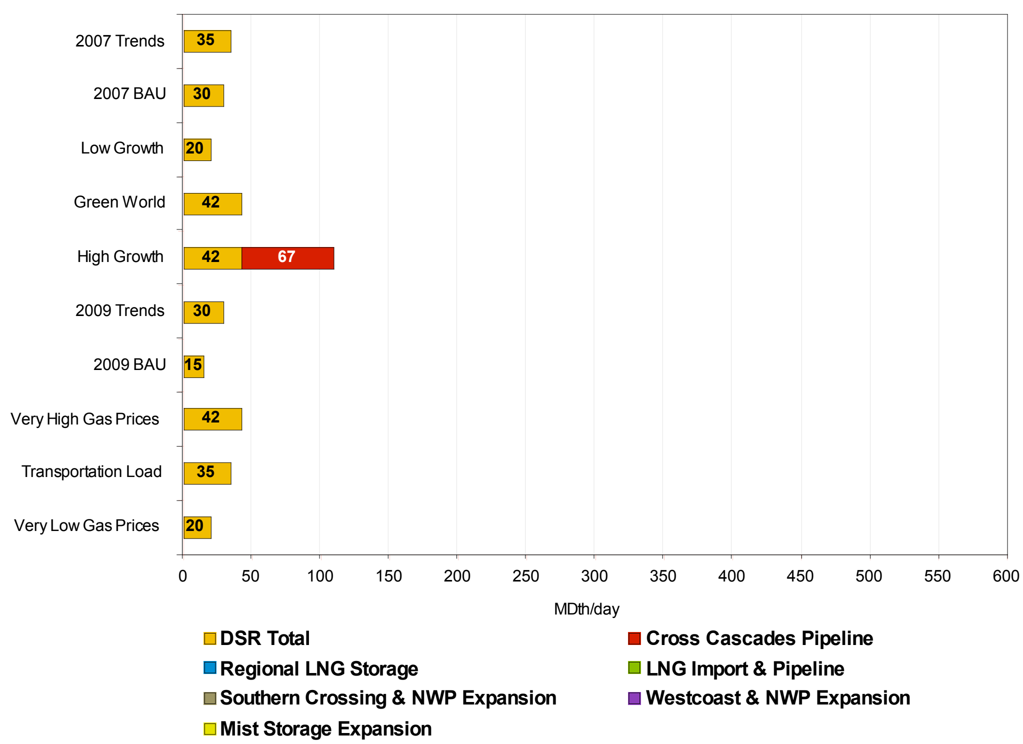


Figure 6-24
Gas Resource Additions in 2020

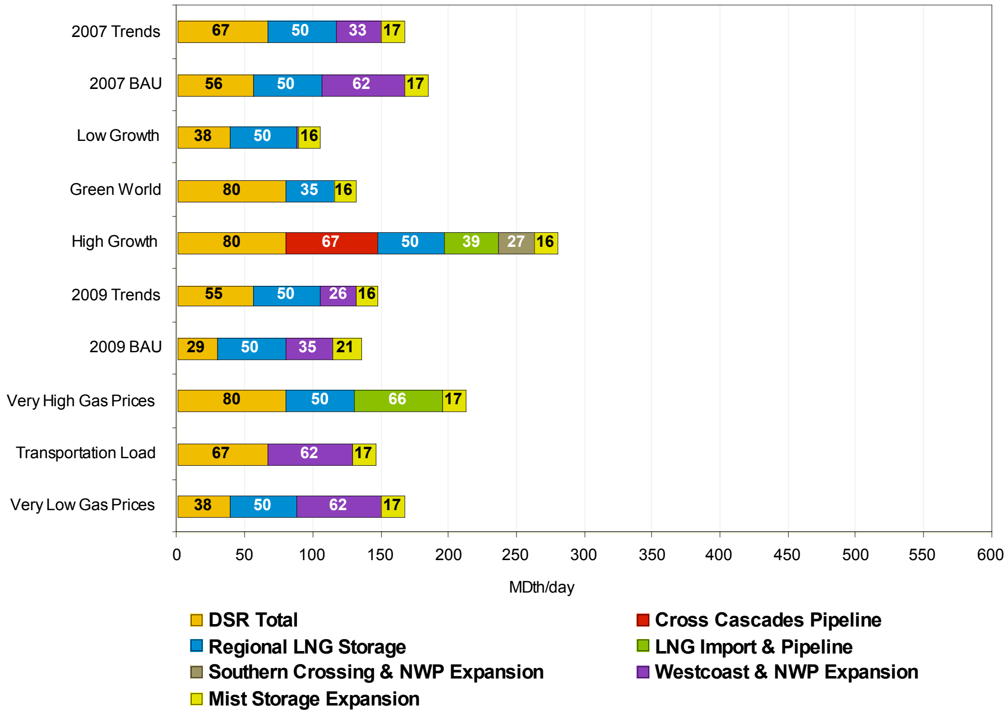


Figure 6-25
Gas Resource Additions in 2025

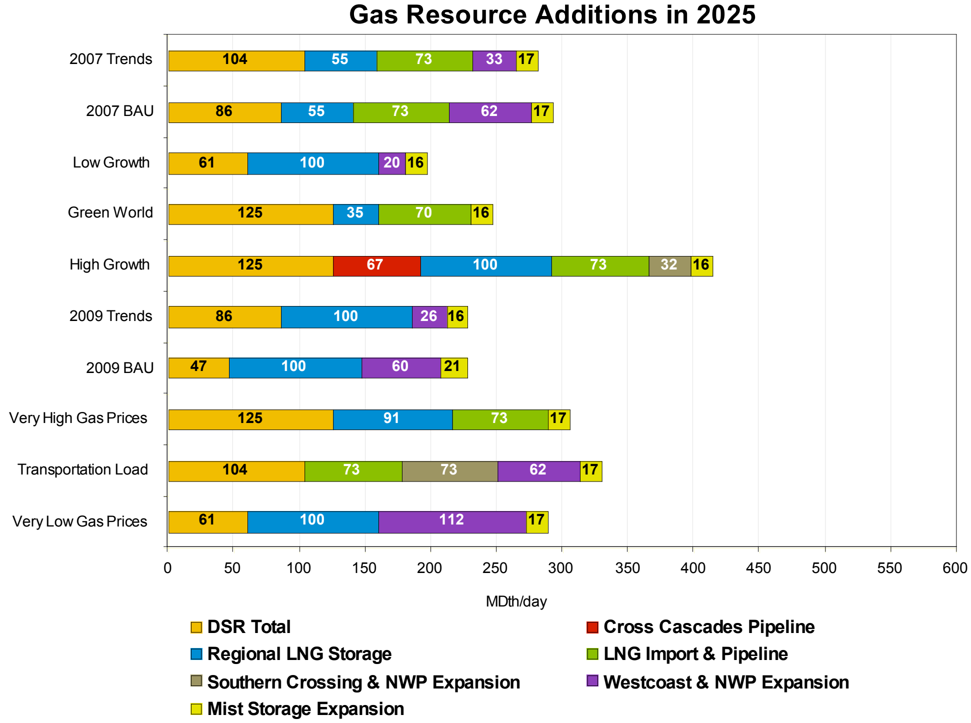
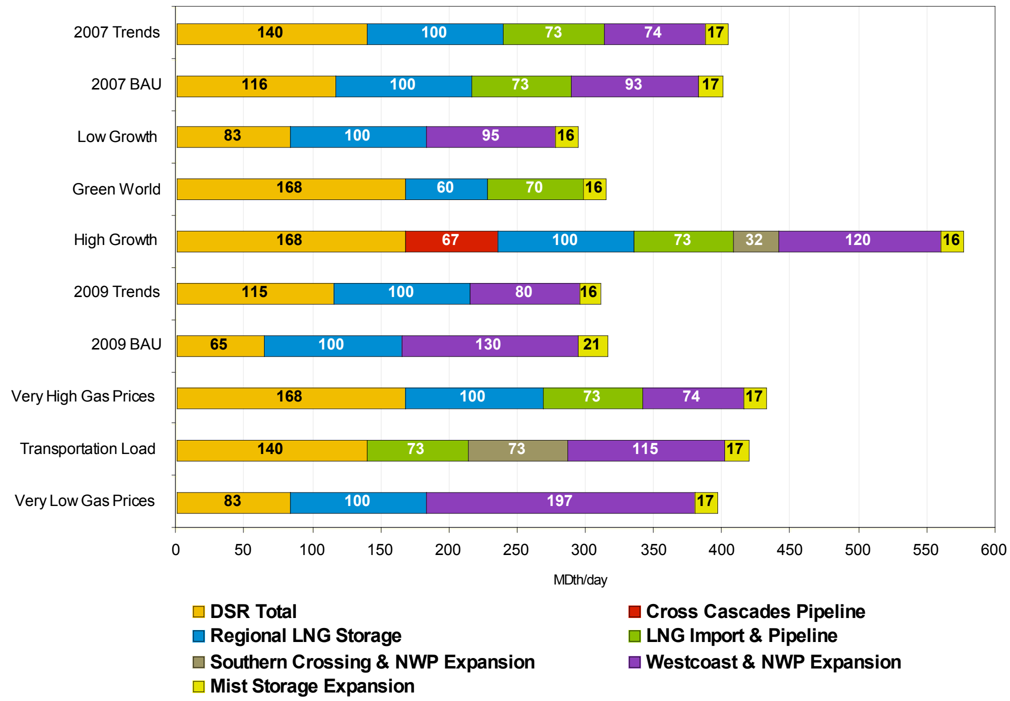


Figure 6-26
Gas Resource Additions in 2029



Pipeline Capacity Additions

The analysis includes the Cross Cascades and Southern Crossing alternatives only in the High Growth scenario. The Green World scenario doesn't include any of these pipeline alternatives.

Storage Additions

The results indicate that PSE should continue to consider a regionally located LNG storage facility as well as a limited amount of storage at the Mist facility between 2015 & 2020. The northern British Columbia storage alternative was not selected in any of the scenarios.

Supply Additions

In the real world, PSE continues to rely on acquisition of natural gas from creditworthy and reliable suppliers at major market hubs or production areas. For the IRP SENDOUT model, we assumed continuation of geographically diverse, long-term supply contracts (currently about two-thirds of annual requirements) throughout the planning horizon. The optimal portfolio would contain additional gas supply from various supply basins or trading locations, along with optimal utilization of existing and new capacity.

An imported LNG supply terminal built on or near the mouth of the Columbia River with new and/or expanded pipeline capacity for delivery to PSE's service territory was also considered. LNG imports were included in the Very High Gas Price test and High Growth scenarios by 2020 and in additional scenarios by 2025 and 2029. As mentioned earlier, the future of LNG imports into the Pacific Northwest is unclear. Capital costs of building the supply infrastructure (liquification, transportation, and vaporization facilities) is very high, and the delivered gas costs advantages over domestic supplies is not apparent – at least over the next few years.

Energy Efficiency Additions

The optimal level of energy efficiency resources for the integrated gas sales portfolios was determined by SENDOUT, as described earlier.

Demand-side bundles demonstrated sensitivity to avoided costs, as illustrated in Figure 6-27, responding to various scenario assumptions about load growth, carbon costs, gas prices, resource costs, etc. In addition, gas price sensitivities were tested and showed an impact on the amount of efficiency potential.

Figure 6-27
Gas Energy Efficiency Savings by Scenario

Compared to the previous plan, this IRP analysis revealed an upward shift in the gas energy efficiency potentials consistent with the upward trend in gas prices. Higher gas prices resulted in higher avoided costs, so scenarios assuming higher gas prices generally resulted in more energy efficiency potential. The amount of achievable energy efficiency resources selected by the SENDOUT analysis in this plan ranged from roughly 6000 MDth in 2029 for the 2009 Business As Usual scenario to more than double that in the Green World and High Growth scenarios and the Very High Gas Price sensitivity.

The optimal market sector level of demand-side resources selected by the SENDOUT analysis is shown in Fig 6-28 below. For discussion on the bundles, see the “Demand-side Resource Alternatives” section above, and for details on the breakout by end use and measure types in each bundle see Appendix L, Demand-side Resources Analysis.

Figure 6-28
Gas Efficiency Sector Level Savings Bundles By Scenario

	2007 Trends	2007 BAU	Low Growth	Green World	High Growth	Very High Gas Price	Trans Load	Very Low Gas Price	2009 Trends	2009 BAU
Residential Bundle	D	C	B	E	E	E	D	B	C	B
Commercial Firm Bundle	D	B	AL	E	E	E	D	AL	C	AU
Commercial Interruptible Bundle	B	A	AL	D	D	D	B	AL	AL	AU
Industrial Firm Bundle	E	E	E	E	E	E	E	E	E	E
Industrial Interruptible Bundle	E	E	E	E	E	E	E	E	E	E

When higher gas prices are adjusted for, the economic potential of energy efficiency in this IRP is only slightly higher than in 2007. The gas price assumption in the Very Low Gas Price sensitivity was slightly lower than the reference case assumption in the 2007 IRP; the 2009 assumption resulted in a gas energy efficiency potential of 8,000 MDth, compared to 7,000 MDth for the 2007 case. New energy efficiency measures in the 2009 IRP are responsible for the difference.

Figure 6-29 compares PSE's energy efficiency accomplishments, current targets, and our new range of gas efficiency potentials. In the short term, this IRP indicates an economic potential range of 700,000 to 2,000,000 Dth of savings for the 2010-2012 period. This is significantly greater than the historical achievement rate, however, it provides guidance to attain as much cost-effective gas efficiency resources as possible within the constraints of economic and market factors.

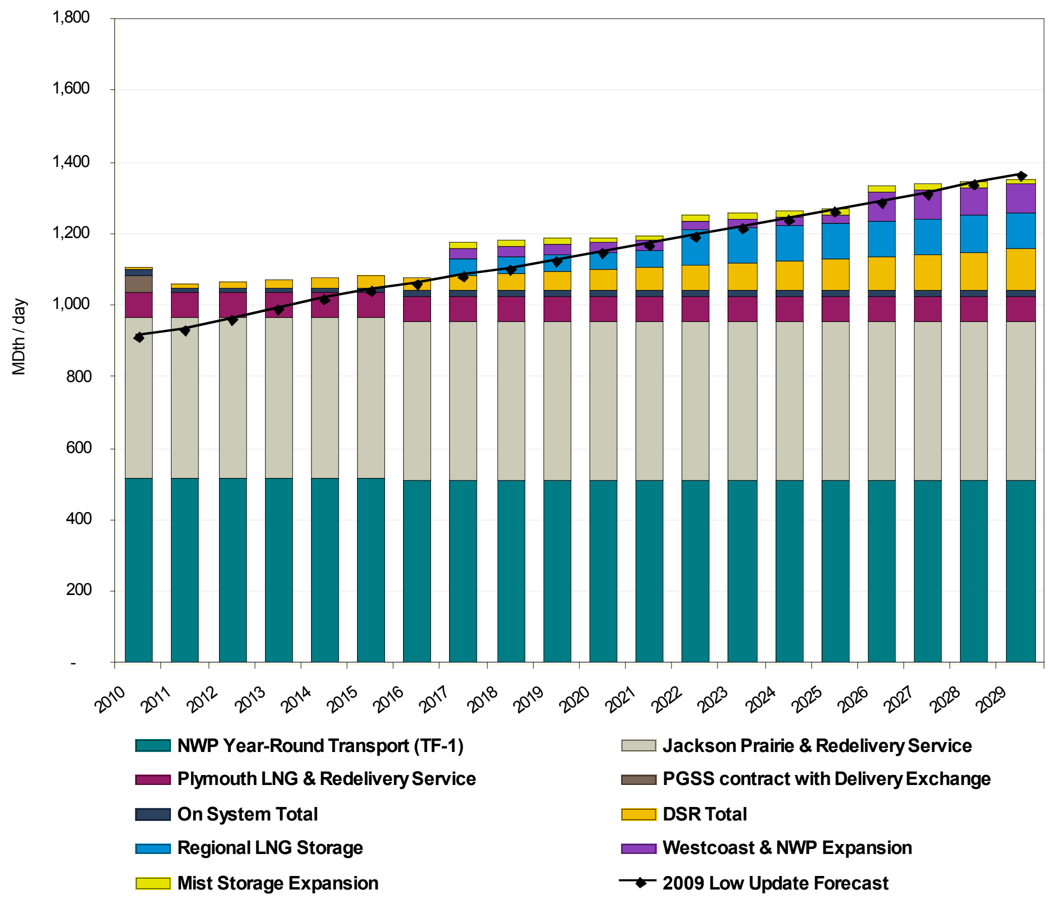
Figure 6-29
Short-term Comparison of Gas Energy Efficiency

Short-Term Comparison of Gas Energy Efficiency	Dth
2006-2007 Actual Achievement	504,000
2008-2009 Target (Updated Jan 2009)	657,000
2010-2012 Range of Economic Potential	700,000 – 2,000,000

Complete Picture: 2009 Trends Scenario

A complete picture of the 2009 Trends scenario optimal resource portfolio is presented below in Figure 6-30. Additional scenario results are included in the Appendix J, Gas Analysis.

Figure 6-30
2009 Trends Gas Resource Portfolio



B. Results of Monte Carlo Analysis on 2009 Trends Portfolio

Monte Carlo analyses on the 2009 Trends scenario optimal resource portfolio provided a reasonable test of whether the company's planning standard (using normal weather with one design peak day per year) creates a portfolio that will meet firm demand under a wide range of different temperature conditions. Results indicate that the 2009 Trends resource portfolio, based on PSE's planning standard, will meet firm demands in over 90% of the draws.

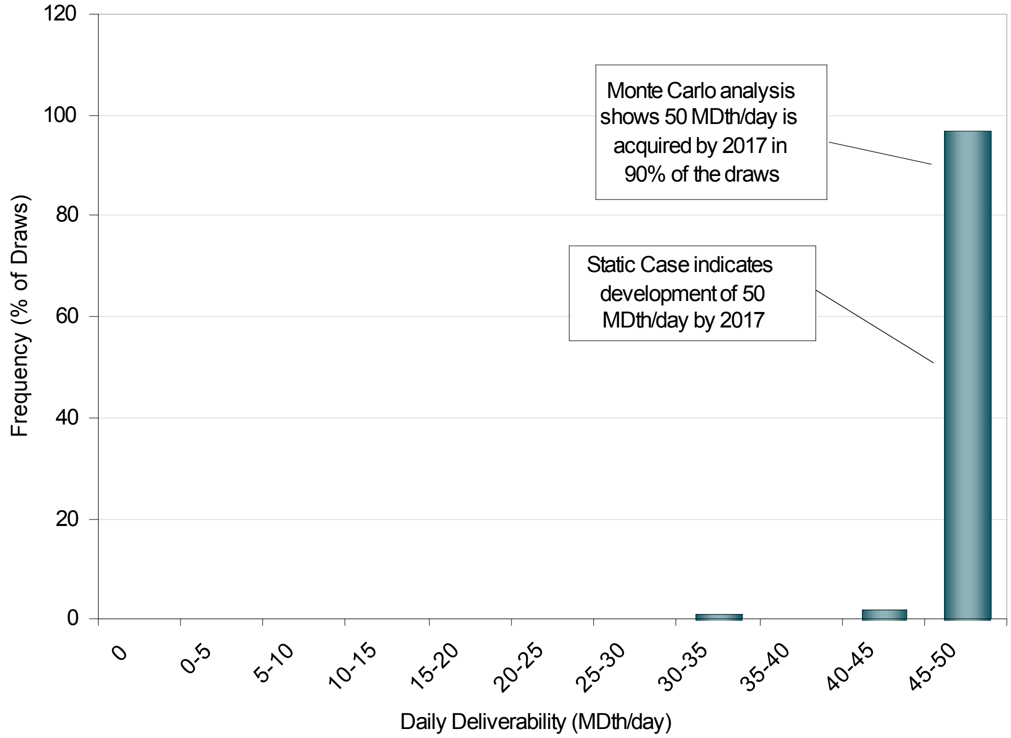
The Monte Carlo analysis also tested the sensitivity of resource additions in the 2009 Trends scenario. Analyses examined six specific resource addition alternatives: the regional LNG storage alternative, the LNG import option, the Southern Crossing/Inland Pacific connector pipeline alternative, the Cross Cascades pipeline alternative, the Mist storage option, and the Northern B.C. storage option. This discussion compares the results from the deterministic analysis with the results from the Monte Carlo resource optimization analysis.

The acquisition of 250 MDth of expanded storage capacity at the Mist facility and 11,250 MDth of capacity in northern British Columbia was selected in all 100 of the draws by 2017. The LNG import alternative was not selected in any of the 100 draws at any time in the analyses.

Regional LNG Storage – Monte Carlo Optimization Results

The regional LNG storage alternative included in the deterministic analysis appears to be sensitive to the specific underlying assumptions. Figure 6-31 shows the frequency distribution with which the regional LNG storage alternative is selected across the 100 scenarios by the year 2017. The Monte Carlo analysis demonstrates that in 17% of the 100 draws, the full regional LNG storage deliverability of 100 MDth per day is developed by 2015, while in 80% of the draws no regional LNG storage is included.

Figure 6-31
Frequency Distribution of Regional LNG Storage Development by 2017

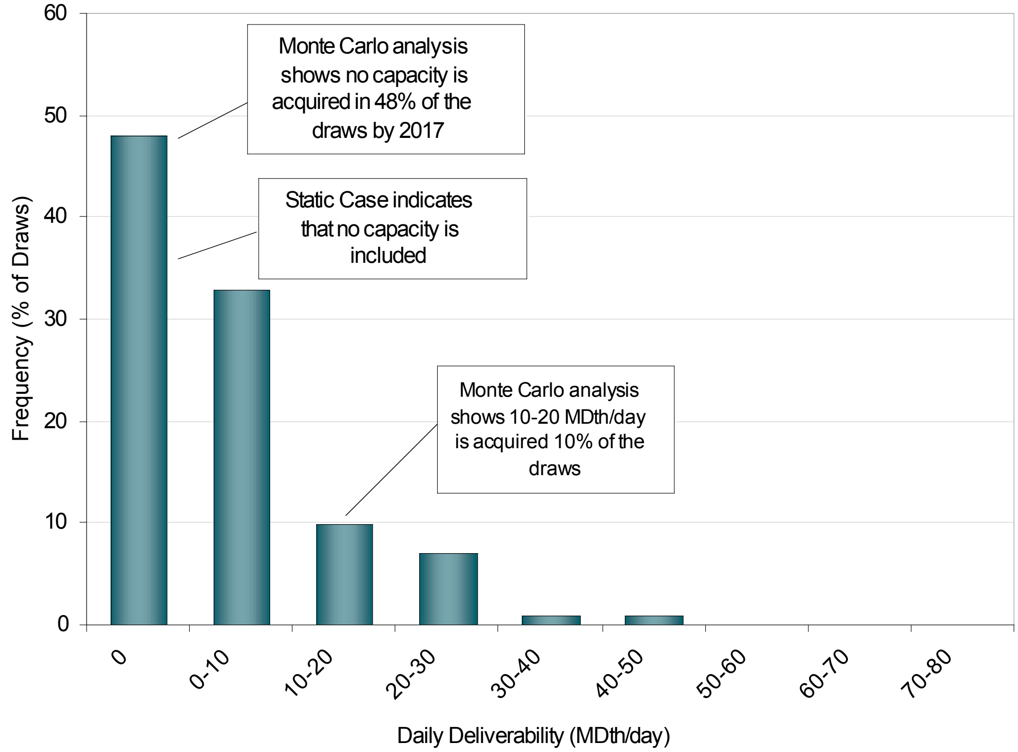


The Monte Carlo analysis indicates that the decision to acquire regional LNG storage capacity is attractive in both the deterministic and Monte Carlo analyses.

Cross Cascades Pipeline – Monte Carlo Optimization Results

Figure 6-32 illustrates the frequency distribution for the Cross Cascades pipeline alternative. As shown, in approximately 48% of the Monte Carlo draws, no Cross Cascades pipeline capacity was selected as part of the optimal resource portfolio. Between 10 and 20 MDth per day of capacity was acquired in 10% of the draws. Note that this option was not selected in the deterministic analyses. These results support the conclusion that PSE may want to acquire a limited amount of Cross Cascades pipeline capacity for the gas sales portfolio if 2009 Trends conditions continue.

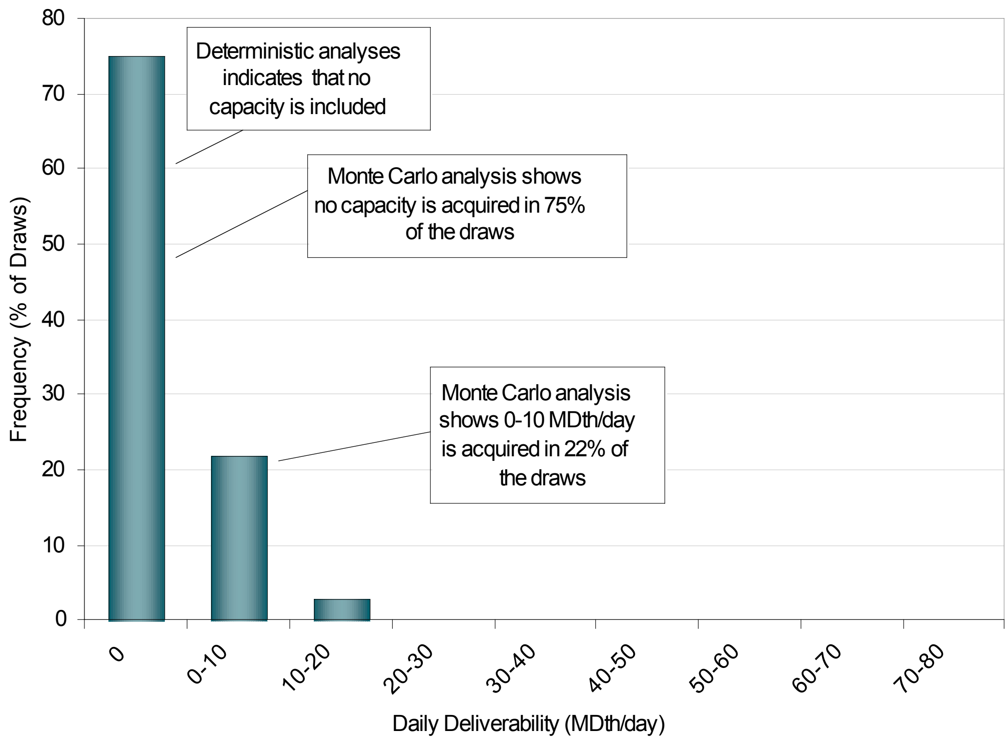
Figure 6-32
Frequency Distribution for Cross Cascades Pipeline by 2017



Monte Carlo Optimization Analysis—Southern Crossing/Inland Pacific Connector

Figure 6-33 shows the frequency distribution for the Southern Crossing/Inland Pacific Connector alternative as well as the results of the deterministic analysis of the 2009 Trends scenario. In 75% of the Monte Carlo scenarios, no Southern Crossing alternative capacity is selected while some, although limited, capacity is selected in the other 25% of the results. No capacity was included in the deterministic analysis.

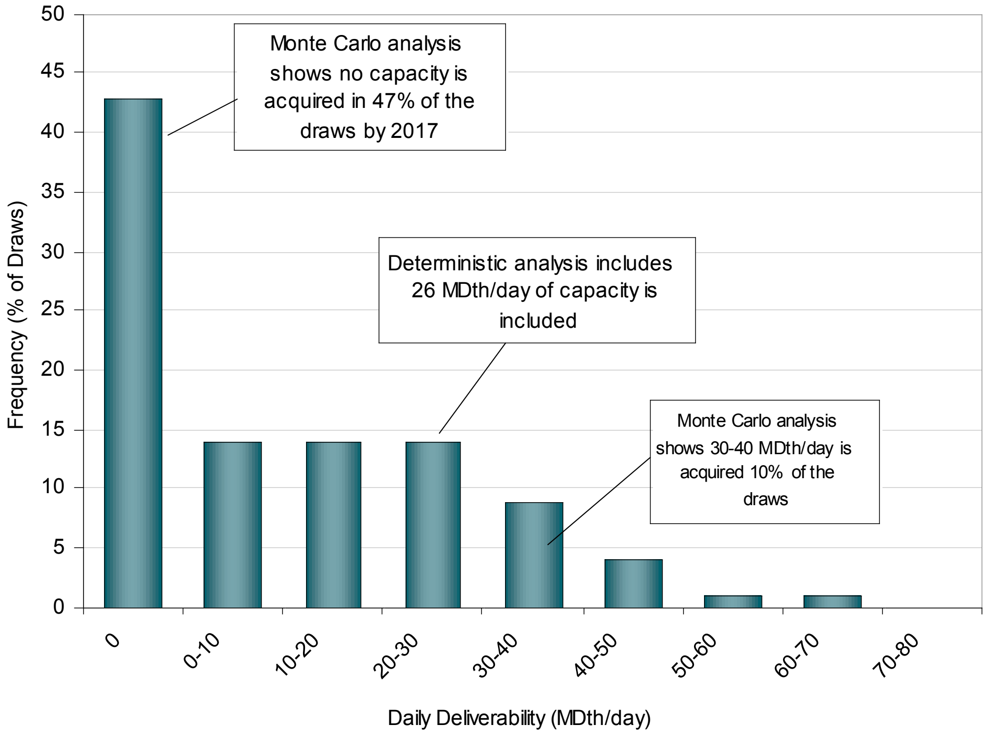
Figure 6-33
Frequency Distribution for Southern Crossing Pipeline Development by 2017



Monte Carlo Optimization Analysis—Summary Conclusion

Figure 6-34 shows the frequency distribution for the NWP alternative from Sumas to PSE's service territory, as well as the results of the deterministic analysis of the 2009 Trends scenario. In 47% of the Monte Carlo scenarios, no NWP Sumas to PSE is selected, while some capacity is selected in the other 25% of the results. Twenty-six MDth per day of capacity was included in the deterministic analysis.

Figure 6-34
Frequency Distribution for NWP Sumas to PSE Service Area by 2017



C. Combined Portfolio and Diversity of Supply Analyses Results

PSE's increasing reliance on natural gas-fueled electric generation makes supply diversity an important issue. Currently, western Canada supplies nearly 70% of the company's combined gas sales and gas for generation portfolios. With time, the need for generation fuel will continue to increase, and exposure to this supply basin could grow even more concentrated. For this reason, PSE is actively investigating acquiring additional Cross Cascades pipeline capacity. Such capacity would allow delivery of gas from the Rockies basin to PSE's service area. The specific routing, design, and costs of this pipeline have not been finalized at this time.

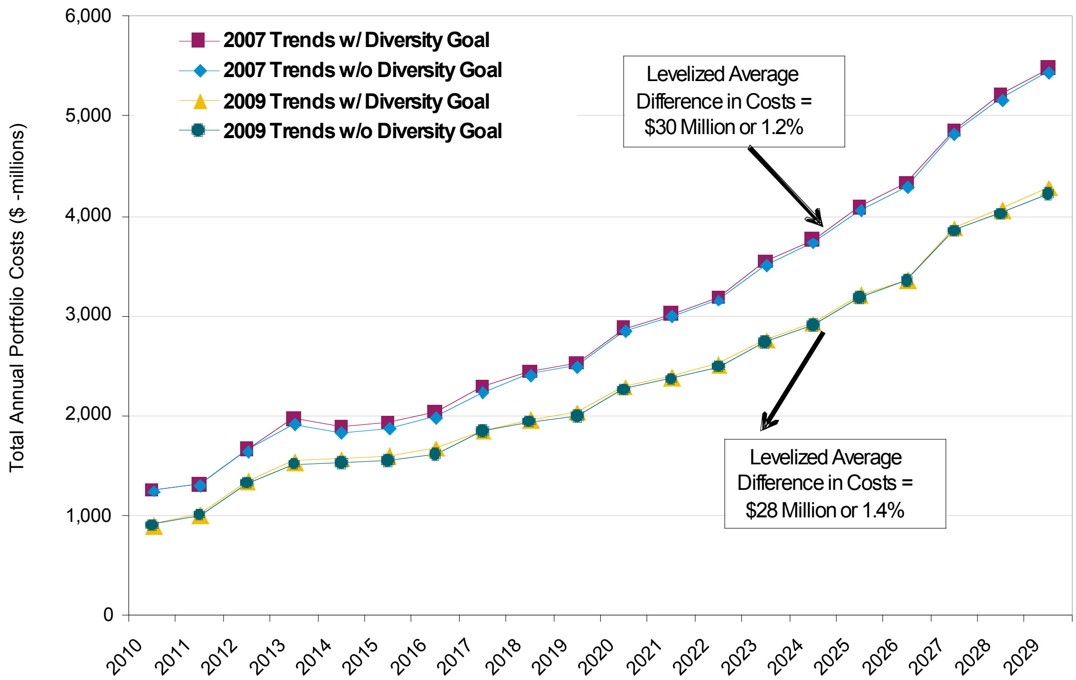
The focus of the combined portfolio analyses was to estimate the direct costs of PSE's acquisition of Cross Cascades pipeline capacity that would increase access to the Rocky Mountain supply basin. The company modeled two scenarios – the 2007 Trends scenario and the 2009 Trends scenario. Two views of each scenario were analyzed: one contained a diversity requirement that constrained access to Canadian supplies beyond a certain percentage of the total, the other did not limit Canadian supplies.

Comparison of Resulting Average Annual Portfolio Costs

The results are shown in Figure 6-35. The upper two lines show the average annual portfolio costs for the 2007 Trends scenario with and without the diversity, i.e. with and without the Cross Cascades alternative. The difference in the costs is relatively small – the annual levelized cost difference over the 20-year period is about $30 million or about 1.2% of the total portfolio cost. The levelized cost of the portfolio including the diversity goal is about $2,463 million compared to $2,433 million for the portfolio without the diversity goal.

The lower two lines show the same data for the 2009 Trends scenario. Again, the costs are relatively close – the levelized cost difference is about $28 million, or about 1.4% of the total portfolio cost ($1,954 million compared to $1,926 million). The difference between the costs for each scenario is largely due to the difference in pipeline transportation costs and the basis differential between Canadian and Rockies market hubs.

Figure 6-35
Cost Projections for Combined Portfolios – Diversity of Supply Analyses



Comparison of Resource Additions

The optimal portfolio resource additions with and without the diversity goal for the 2007 Trends scenario are shown below in Figure 6-36.

Figure 6-36
2007 Trends Scenario
Comparison of Resource Additions With and Without Diversity Requirements

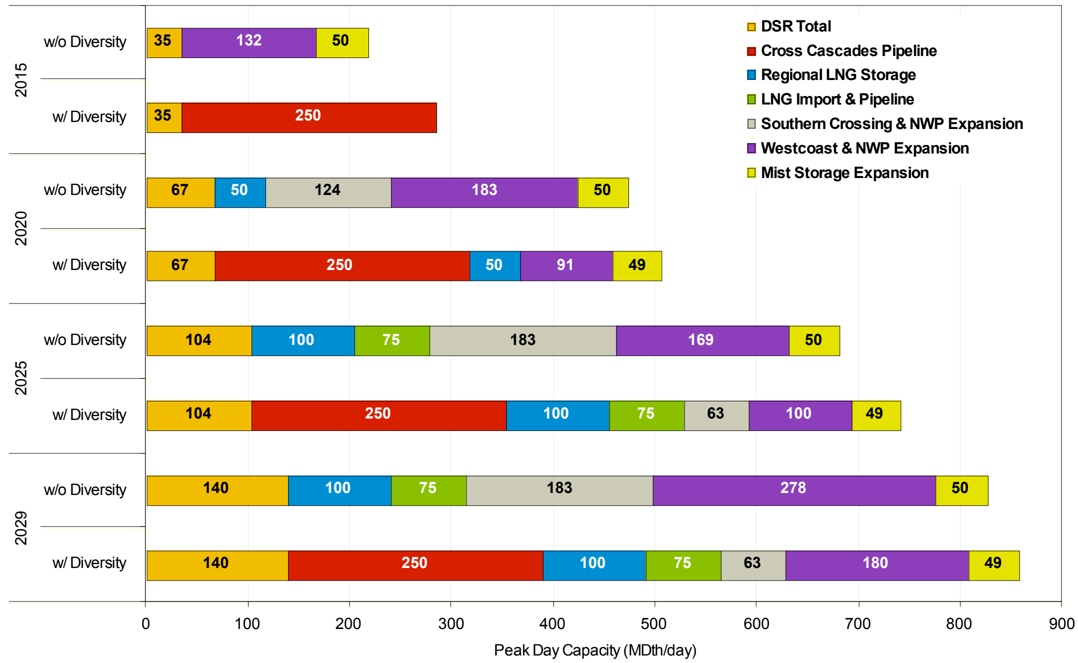
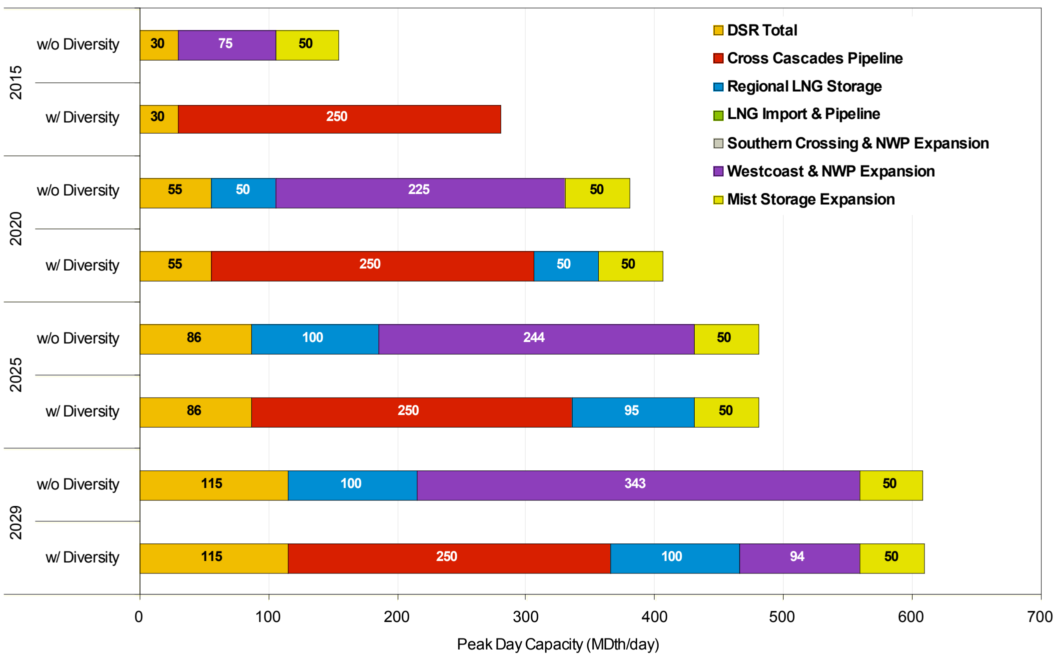


Figure 6-37 contains similar results for the 2009 Trends scenario.

Figure 6-37
2009 Trends Scenario
Comparison of Resource Additions With and Without Diversity Goal



As shown in both cases, the optimal portfolio with the diversity goal includes the addition of the Cross Cascades pipeline alternative with a peak capacity of approximately 250 MDth per day by 2015. Other resource alternatives including DSR, regional LNG storage, Mist storage, and LNG imports are added in later years. Note that some Westcoast pipeline capacity is also added in later years.

In the optimal portfolio without the diversity goal, Southern Crossing and additional Westcoast pipeline capacity essentially replaces the Cross Cascades capacity. The other resource additions are similar to those added in the portfolio with the diversity goal.

D. 2009 Trends (Full-Cap) Combined Portfolio

As discussed earlier in Chapter 5, modification of the electric planning reserve margin calculation changed the gas-fired electrical generating plant additions across all scenarios. In the 2009 Trends scenario, the modified planning reserve margin reduces the CCCT plant additions from 550 MWs (two generating plants including duct firing) to 275 MW (one plant with duct firing) over the 2011-2012 time period. This in turn reduces the peak day gas for generation loads by about 47 MDth per day – the peak day gas loads for a 275 MW plant. This reduction in peak day loads continues until later in the planning horizon. Figure 6-38 compares the peak day gas for generation loads for 2009 Trends and the 2009 Trends (Full-Cap) alternatives.

Figure 6-38
Compare 2009 Trends & 2009 Trends (Full-Cap) Gas for Generation Need (MDth/day)

	2012	2016	2020	2029
2009 Trends	170	170	216	270
2009 Trends (Full-Cap)	123	123	214	268
Change	-47	-47	-2	-2

The gas for generation needs were updated to reflect the reduced need in the 2009 Trends scenario to test the impact of the updated need on the optimal resource additions developed by Sendout. The resource additions from the 2009 Trends and the Final 2009 Trends scenario are shown in Figure 6-39 below. The difference in total resource additions are also shown at the bottom of Figure 6-39. As shown, the difference in Westcoast/NWP resource additions reflect the difference in peak day loads.

Figure 6-39
2009 Trends and Final 2009 Trends Scenario Optimal Resource Additions

2009 Trends

	Additions in MDth/day				
	Cross Cascades Pipeline	Regional LNG Storage	Westcoast/ NWP	Mist Storage & Pipeline	DSR
2012			75	50	14
2017		50	150		26
2022		50	19		27
2026			99		26
2029					22
Total Additions	**0**	**100**	**343**	**50**	**115**

2009 Trends (Full-Cap)

	Additions in MDth/day				
	Cross Cascades Pipeline	Regional LNG Storage	Westcoast/ NWP	Mist Storage & Pipeline	DSR
2012			50	50	14
2017		50	129		26
2022		50	19		27
2026			144		26
2029					22
Total Additions	**0**	**100**	**342**	**50**	**115**
Difference	**0**	**0**	**-1**	**0**	**0**

As discussed earlier in Chapter 5, the change in the reserve margin assumption appears to have a consistent impact across all portfolios with similar load assumptions. There is no evidence to support that the impacts due to the modified planning reserve margin will not change the relative costs or risks of the portfolios.

The quantitative analyses presented in this chapter are based largely on the results of optimization models. While quantitative analyses delivers a great deal on information about how resources will perform over time, developing resource strategies also involves applying judgment based on customer preferences, utility operations in the marketplace, and observation of regulatory developments. The final gas sales and combined portfolios presented in Chapter 8 are based on these analyses as well as the additional considerations discussed in Chapter 8.

VI. Key Findings

The key findings from this analytical and statistical evaluation will provide guidance for development of PSE's long-term resource strategy, and also inform consideration of specific resource development activities over the next two years.

1. The growth in the need for generation fuel will outpace the growth in need for gas sales.

The increase in both peak capacity and annual volumes of gas for generation fuel will exceed the increases in need for the gas sales portfolio.

2. Investigate expanding gas energy efficiency programs.

The economic potential for gas efficiency in the lowest scenario is close to the current acquisition rate but in every other scenario it extends higher. Although the acquisition rate is often constrained by economic and market factors, the best way forward is to attempt to acquire as much gas efficiency resources as feasible.

3. Determine the most cost-effective Cross Cascades pipeline alternative and investigate joint participation and sponsorship in order to diversify PSE's supply alternatives to include additional Rockies supply.

At this point, it appears that the benefits of the increased supply diversity associated with the Cross Cascades pipeline outweigh the additional costs. If the Rockies gas supplies continue to be significantly lower cost (about $1.50 lower through 2013 at this point) than Canadian supplies, gas supply savings will largely offset the additional pipeline transportation costs. The I-5 corridor region will need additional pipeline capacity at some point over the next three to seven years.

4. Investigate participation in or development of a jointly owned LNG storage facility located to take advantage of locational displacement for low-cost withdrawal transportation to PSE's service area.

This alternative appears to be a feasible and low-cost alternative to meet future peak load growth.

5. Monitor the development of regional LNG import facilities.

Imported LNG may be an attractive supply alternative later in the planning horizon. At this time, the terms for supply of gas to the LNG terminal have not been developed, nor has PSE had the opportunity to discuss what form such a supply agreement might take. The final terms and conditions of the gas supply agreement will largely determine the attractiveness of this alternative.