Gas Analysis

Contents

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.

1. Gas Resource Need

This IRP develops an integrated resource plan for PSE's gas sales customers, and it also examines the utility's "gas-for-power" need. The former fulfills regulatory requirements, while the latter adds crucial context around a resource that has become increasingly important to meeting customers' electric demand. Here, we present three views of gas resource need – gas for sales, gas for power, and combined gas need – and discuss some of the important ways in which they are interrelated.

"Gas for sales"
refers to PSE's direct delivery of natural gas to end-use customers.

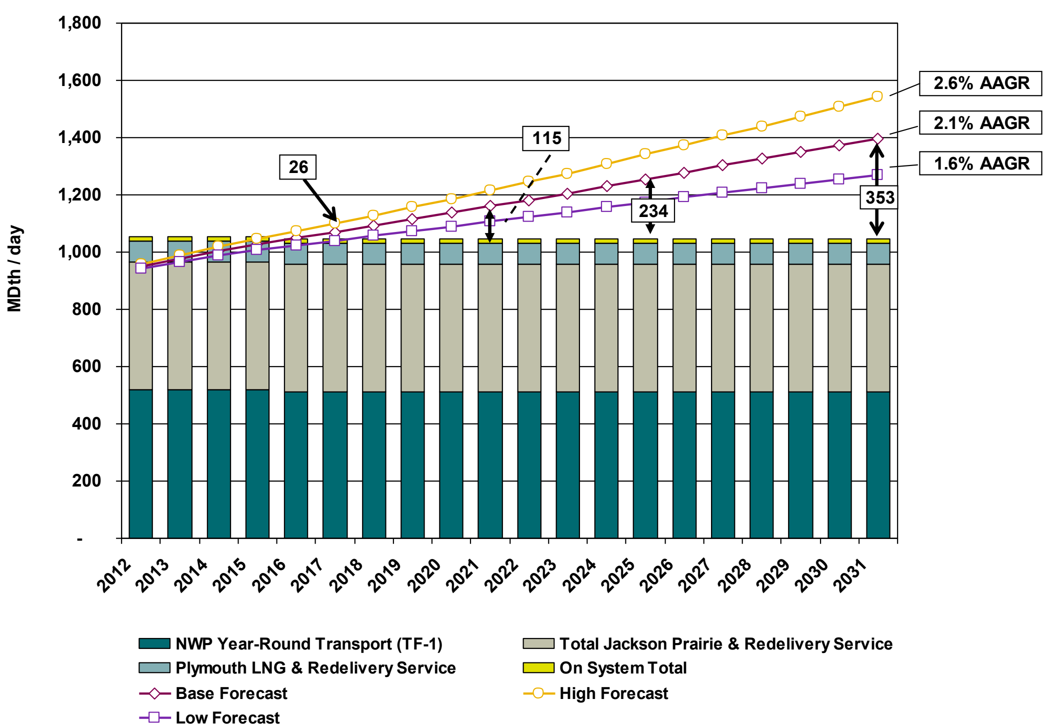
"Gas-for-power"
refers to the fuel needed to run generators that produce electricity.

"Combined gas need"
refers to the aggregate of "gas for sales" and "gas for power".

Gas Sales Need

Figure 6-1 illustrates gas sales resource need over the 20-year planning horizon. The lines rising toward the right indicate demand, and the bars below represent current contracts for the pipeline transportation, storage, and peaking capacity that enable PSE to transport gas from points of receipt to customers.

Figure 6-1
Gas Sales Resource Need
Existing Resources Compared to Peak Day Demand
Meeting need on the coldest day of the year



Gas sales need is driven by two factors: peak day demand per customer and the number of customers. For PSE, peak-day demand occurs in the winter, when temperatures are lowest and heating needs are highest. Since the heating season and number of lowest-temperature days[1] in the year remain fairly constant, customer count is the biggest factor

[1] *For gas peak day planning purposes PSE assumes a day with 52 Heating Degree Days (HDDs) or an average temperature of 13° F.*

in load growth. The analysis tested three customer growth forecasts over the 20-year planning horizon: the Base Case growth forecast assumes customer growth of 2.13% per year, the High forecast assumes 2.54%, and the Low forecast assumes 1.75%.

In the Base Case forecast, we currently have sufficient resources to meet peak day need until the winter of 2015-16. Under the High forecast, additional resources will be needed by the winter of 2014-15. Under the Low forecast, additional resources are not needed until 2017-18.

Gas-for-power Need

Natural gas for power generation is increasingly important to the electric side of the utility. Every IRP since 2003 has identified natural gas-fired generation as the most cost-effective supply-side resource to include in IRP portfolios. This planning cycle is no different: All of the electric portfolios produced by the analysis include the addition of substantial amounts of gas-fired generation as part of the solution to meeting future electricity demand.

Calculating gas-for-power need is not as straightforward, since different types of gas-fired generating plants require different types of natural gas resources and their dispatch is dependent upon the prevailing market heat rate. Combined-cycle combustion facilities (CCCTs) are assumed to need firm gas transportation. Simple-cycle combustion engines (peakers) are expected to operate with temporary pipeline capacity purchased from the gas sales book, the pipeline, or through the capacity release market – and rely on oil back-up when none is available.

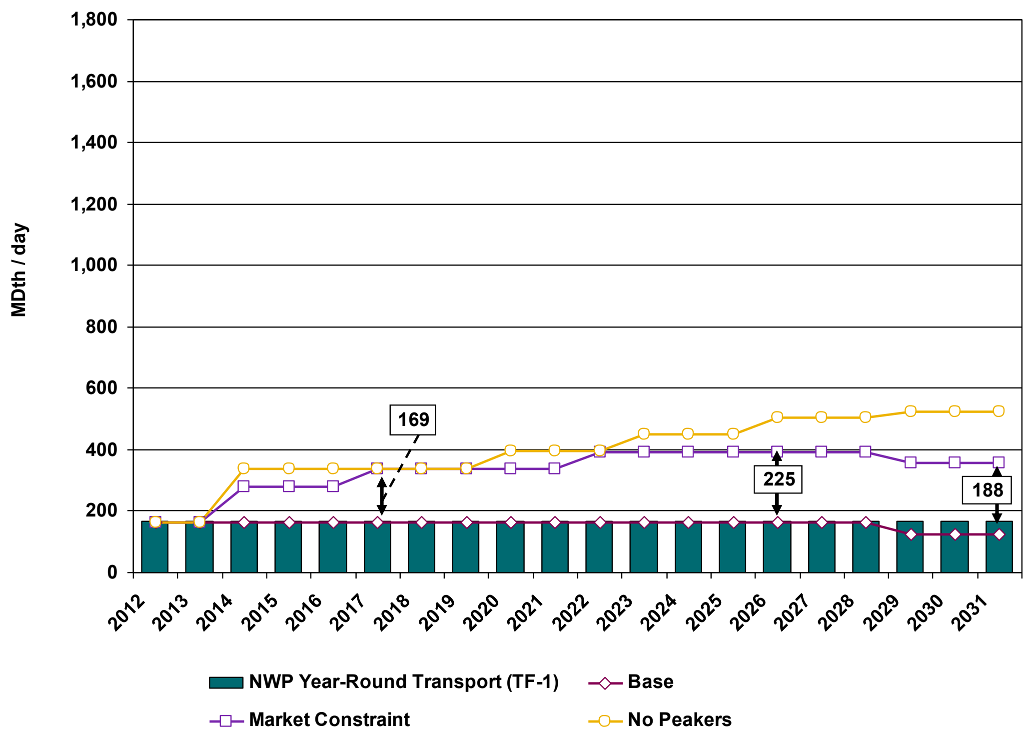
The chart below describes gas for power needs under three sets of circumstances. All use the Base Case scenario assumptions, but each uses a different combination of CCCT and peaking plants.

- The **Base** portfolio represents the all-peaker portfolio identified as lowest reasonable cost in the electric analysis.
- The **No Peaker** sensitivity represents a portfolio that essentially replaces peakers with CCCTs.
- The **Thermal Mix** sensitivity represents a portfolio in which market exposure is limited to 40% of total portfolio cost.

The primary difference among the three is the number of peakers and/or CCCTs and, as a result, the amount of firm gas transport capacity needed. In the Base Case scenario, all of the new gas-fired generating capacity is comprised of peakers, which do not require firm gas pipeline capacity. The other cases include CCCTs and more firm gas transport capacity.

Different generating plants require different gas resources.

Figure 6-2
Three Views of Gas-for-power Resource Need
Existing Resources Compared to Peak Day Demand
Different generating plants require different gas resources



Combined Gas Resource Need

The extreme peak for both gas sales and gas for power loads typically occurs on the very coldest days of the winter. To depict combined need, we added the peak gas sales need identified in the gas sales Base Case to each of three views of gas-for-power need: the electric Base Case scenario, the Thermal Mix sensitivity, and the No Peakers sensitivity. (Their differences are explained in the preceding two pages.) Extreme peak combined need is summarized in Figure 6-3 below. Combined need varies from 310 to 709 MDth per day by 2031, depending upon which gas-for-power scenario is assumed.

Figure 6-3
Combined Gas Resource Need (Net Need in MDth/day)
Extreme peak for gas sales and gas for power

Gas Sales Base plus . . .	2016-17	2020-21	2025-26	2030-31
Electric Base Case	20	109	228	310
(El.) Thermal Mix	194	284	459	541
(El.) No Peakers	195	342	572	709

Observations

The yearly demand curves for gas sales and gas for power differ in ways that create some interesting relationships. The very coldest winter days create short-term spikes in both portfolios, but in general, gas for sales demand is highest in the winter when heating needs are the greatest, while sustained high demand for gas for power occurs in the summer because the summer electric market is heavily influenced by California air-conditioning loads.

The gas sales portfolio purchases a substantial amount of firm pipeline capacity to make sure it can deliver all the gas customers need in the winter, but when summer comes and demand for gas sales subsides, it has surplus capacity. This means that the gas sales portfolio has excess capacity at the same time the electric utility needs to acquire capacity to meet its high-demand, summer season needs. Per WUTC requirements, short-term surplus capacity of the gas sales portfolio is made available to the generation portfolio at prevailing market rates similar to the rates that would result from release to a third party through FERC-regulated capacity release rules or available for purchase from the pipeline.

Firm, year-round pipeline capacity incurs demand charges whether the capacity is used or not and generally requires a multi-year commitment. Short-term firm and interruptible pipeline capacity, purchased from the pipeline and the short-term capacity release market (in which firm capacity holders sell excess capacity to others), is generally less expensive.

Figures 6-4 and 6-5 compare the 2009 and 2010 demand curves for the gas sales and gas-for-power portfolios.

Figure 6-4
2009 Daily Gas Sales and Gas for Power Loads
Comparing demand curves and volatility

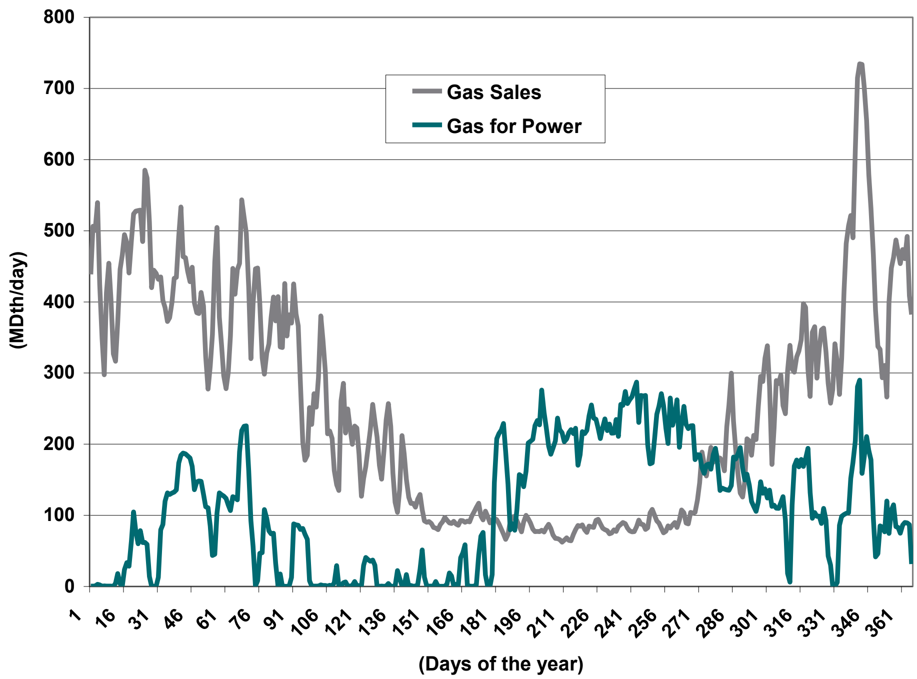
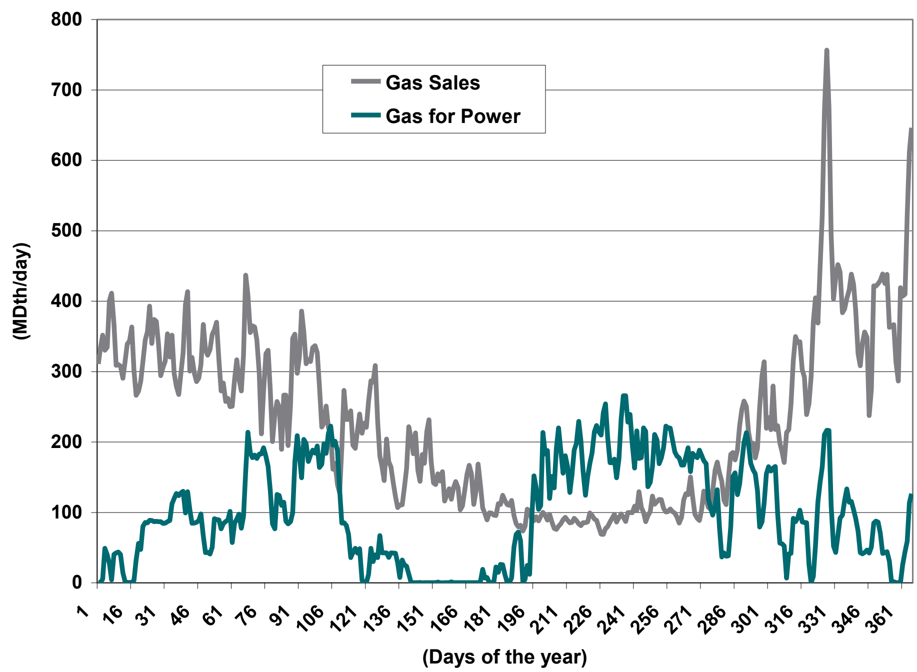


Figure 6-5
2010 Daily Gas Sales and Gas for Power Loads



The growing reliance on natural gas to generate electricity increases the need to add gas storage capacity in the electric resources portfolio.

Gas-for-power loads are much more variable than gas sales loads. Another look at the historical data pictured in Figures 6-4 and 6-5 shows that average gas-for-power loads are less than half the size of average gas sales loads – but their swings in volume (their maximum daily increase and decrease) are about the same. This is confirmed by volatility statistics, which are much higher for gas-for-power loads than gas sales.

Significant additions of gas-fired generation resources – as with the 2,343 MW of peaking plants added in the electric resource portfolio developed for this IRP – could create unprecedented swings in gas loads. As peakers are switched on to meet demand, a volume of gas equivalent to PSE's entire gas sales load on a typical winter day could be required, and by 2020, day-to-day swings in gas volumes for generation fuel could be three times greater than the swings PSE has seen with its entire gas utility load historically.

Near-term, using the gas sales portfolios excess capacity or the capacity release market to supply 2 or 3 additional peaking plants makes a great deal of sense, provided such plants can be permitted to use back-up fuel during peak periods; however, it is not at all clear that the capacity release market and pipeline system can handle the volume of activity required for the 11 peakers projected in the Base Case scenario by 2031. Increased storage would greatly improve the ability to manage those swings, and may become a crucial part of the supply chain for generation.

Figure 6-6
Variability of Gas Sales and Gas-for-power Loads Compared
Volatility and volumes

	Gas Sales	Gas for Power
Calendar Year 2009		
Maximum	735	290
Minimum	62	0
Average	252	110
Max Daily Increase	133	129
Max Daily Decrease	126	131
Volatility	0.13636	1.36582
Calendar Year 2010		
Maximum	757	266
Minimum	69	0
Average	229	99
Max Daily Increase	147	104
Max Daily Decrease	180	107
Volatility	0.13937	1.14443

Acquisition choices will affect the amount and type of gas resources needed in the electric portfolio. Additional peaking plants proved to be the lowest reasonable cost supply-side resource alternative in the electric portfolio developed for this IRP, but when the time comes to actually make acquisitions, purchased power agreements may be judged more cost-effective. Less likely but still possible, CCCT plants may be economically attractive because of their more efficient heat rate. These choices would have very different impacts.

- Choosing purchased power agreements would reduce the amount of natural gas resources needed.
- Choosing CCCTs would increase the need for firm gas transportation.
- Peaking plants without alternate back-up fuel capability would increase the need for firm gas transportation.

Gas transportation needs are also highly dependent on the specific location of generating plants.

For example, plants located near a gas trading hub or storage facility need less pipeline capacity to transport fuel but may need more transmission to transport power; conversely, plants located near PSE loads require less electrical transmission but may require more gas transport capacity.

2. *Existing Gas Resources*

Gas Sales Supply-side Resources

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 (Dth) per day of firm, year-round TF-1 (firm) 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

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 6-7
Pacific Northwest Regional Gas Pipeline Map

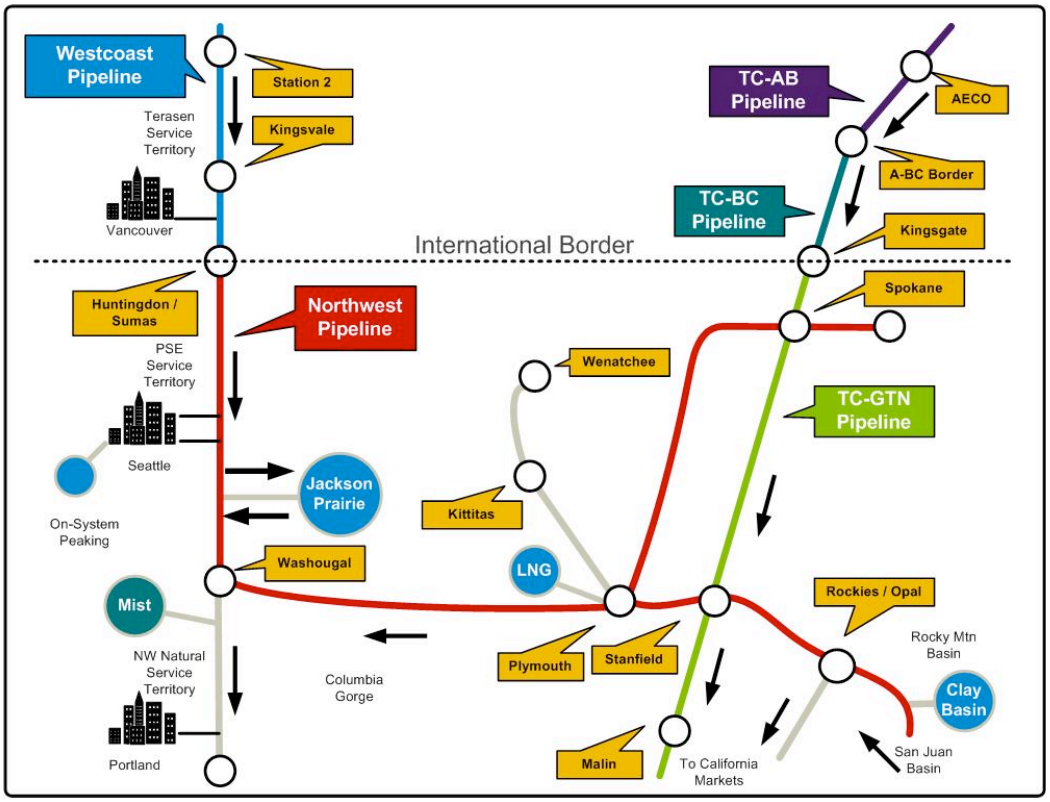


Figure 6-8

Gas Sales Pipeline Capacity (Dth/day) (as of 01/01/2011)

Pipeline/Receipt Point	Note	Total	Year of Expiration 2012	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				2015
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	129,851	11,246	-	75,482	25,675 (2017) 17,449 (2018)
Total Upstream Capacity	**8**	**378,618**				

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 supplies purchased at Sumas.*

It is helpful to understand the significant differences among transportation types, especially TF-1 and TF-2 service, and firm and interruptible capacity.

TF-1 and TF-2 service. TF-1 transportation contracts are firm contracts, available 365 days each year. TF-2 service is for delivery of storage volumes and is generally intended for use during the winter heating season only; contract costs are based on a quantity related to the storage capacity referenced by each respective agreement. Therefore, TF-2 service has significantly lower annual costs than the 365-day service provided under TF-1. The special winter-only TF-1 service has similar characteristics and pricing as TF-2 service.

Firm and interruptible capacity. Firm transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity of gas on the pipeline. Firm transportation requires a fixed payment, whether or not that capacity is used. Interruptible service is subordinate to the rights of shippers who hold and use firm transportation capacity; the rate for interruptible capacity is negotiable, and is typically billed as a variable charge. When firm shippers do not use their firm pipeline capacity, they may release it on the capacity release market.

PSE releases capacity when we have a surplus of firm capacity 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 plays a limited role in PSE's resource portfolio, because it cannot be relied on to meet peak demand.

Existing storage resources. PSE's natural gas storage capacity is a significant component of the company's gas resource portfolio. Storage capacity improves system flexibility and creates 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 storage 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, generally at lower prices.
- Combining storage capacity with seasonal TF-2 (or special winter-only TF-1) transportation allows us to contract for less 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.

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 6-9 presents details about storage capacity.

Figure 6-9
Gas Sales Storage Resources[1]

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned[2]	8,220,000	199,334	398,667	N/A
Jackson Prairie – Owned[3]	(500,000)	(25,000)	(50,000)	2011
Jackson Prairie – NWP SGS-2F[4]	1,181,021	24,195	48,390	2012
Jackson Prairie – NWP SGS-2F[4]	281,242	4,789	9,577	2026
Clay Basin[5]	12,882,750	53,678	107,356	2013/20
Total	**22,065,013**		**513,990**	

Notes:
1) *Storage, injection, and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.*
2) *Storage capacity at 12/31/2010. Storage capacity at this facility will continue to grow through 2012.*
3) *Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs.*
4) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
5) *PSE expects to renew the Clay Basin storage agreements.*

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 minimize 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 (Jackson Prairie), 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 contracts for SGS-2F storage service from NWP. The NWP contracts are automatically renewed each year but we have the unilateral right to terminate the agreement with one year's notice.

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 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated agreement.

We use Clay Basin for certain levels of baseload supply, and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains, during the winter. It provides a reliable source of supply throughout the winter, including 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. PSE also pays a variable charge for gas injected into and withdrawn from Clay Basin. 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.

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 6-10
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	15,750	3,000	5,250	On-system
Swarr LP-Air	128,440	16,680 (1)	10,000	On-system
Total	**385,890**	**20,888**	**85,750**	

Notes:

1) *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 of 241,700 Dth, a liquefaction Maximum Daily Quantity (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 satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of our distribution system. The Gig Harbor plant receives, stores, and vaporizes LNG that has been liquefied at other LNG facilities; it represents an incremental supply source and is therefore included in the peak day resource stack. Although the 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.

Swarr LP-Air. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth equivalent, and can vaporize the equivalent of 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. For peak-day planning purposes, we consider this facility capable of supplying only 10,000 Dth per day.

Existing gas supplies. Development of the means to economically extract natural gas from shale deposits has changed the picture with regard to gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on Western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its 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. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide flexibility to buy from the lowest-cost basin. While we are heavily dependent on supplies from northern British Columbia, we also maintain pipeline capacity access to producing regions in the Rockies, the San Juan basin, 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 several years, but should be 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 and San Juan basin, there are various transportation receipt points, including Opal and Clay Basin; but alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the 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 nearer producing areas 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. Longer-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. Near-term 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 and Clay Basin), day-ahead purchases, and off-system sales transactions, and balances intra-day positions using Jackson Prairie. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE’s low load-factor market is highly weather-dependent and, therefore, seasonal in nature. 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.

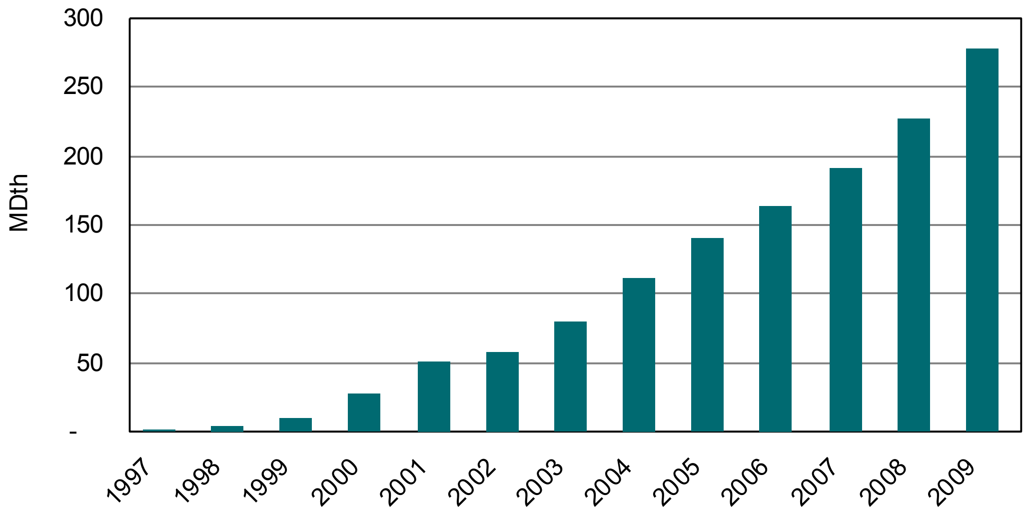
Gas Sales Demand-side Resources

PSE has provided demand-side resources or DSR (that is, resources generated on the customer side of the meter) since 1993. Figure 6-11 shows that energy efficiency measures installed through 2009 have saved a cumulative total of 2.8 million Dth – more than half of which has been achieved since 2004. 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.

PSE's energy efficiency programs serve residential, low-income, commercial, and industrial customers. Energy savings targets and the programs to achieve those targets are established every two years. The 2008-2009 biennial program period concluded at the end of 2009; current programs operate January 1, 2010 through December 31, 2011. The majority of gas energy efficiency programs are funded using gas "tracker" funds collected from all customers.

For the 2010-2011 period, a two-year target of approximately 900,000 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).

Figure 6-11
Gas Sales Energy Efficiency Program Summary



Gas for Power Supply-side Resources

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, as of 01/01/2011)

Direct-connect Capacity						
Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2011	Yr. to Yr.
Encogen	Cascade Natural Gas	Firm	(2)	NWP (Bellingham) to Plant	2012	Yr. to Yr.
Fredonia	Cascade Natural Gas	Firm	(2)	NWP(Sedro-Wooley) to Plant	2021	Yr. to Yr.
Mint Farm	Cascade Natural Gas	Firm	(2)	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 (4)	2018	Yr. to Yr

Upstream Capacity						
Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Various	Westcoast	Firm	21,829 (3)	Station 2 to Sumas	2014	Yes
Various	Westcoast	Firm	47,354 (3)	Station 2 to Sumas	2018	Yes
Various	NWP	Firm	2,128	Stanfield to Deer Island	2025	Assumed
Various	NWP	Firm	4,928	Stanfield to Bellingham	2025	Assumed
Various	NWP	Firm	21,872	Stanfield to Jackson Prairie	2025	Assumed
Various	NWP	Firm	2,000	Sumas to Tacoma	2013	Yes
Various	NWP	Firm	25,000	Sumas to Deer Island	2013	Yes
Various	NWP	Firm	25,000	Sumas to Longview	2012	No
Various	NWP	Firm	10,710	Sumas to Stanfield	2044	Yes
Various	NWP	Firm	500	Sumas to Longview	2044	Yes
Various	NWP	Firm	9,000	Sumas to Longview	2012	Yes
Storage Capacity						
Plant	Transporter	Service	Deliverability (Dth/day)	Storage Capacity (Dth)	Year of Expiration	Renewal Right
Jackson Prairie	PSE	Firm	6,704	140,622	2012	Yes
Jackson Prairie (5)	PSE	Firm	50,000	500,000	2011	No

Notes:

1) *50% of plant requirements*
2) *Full plant requirements.*
3) *Converted to approximate Dth/day from contract stated in cubic meters/day.*
4) *Gas transported from Everett to Goldendale under NWP flex rights, backed by exchange agreement with PSE's gas sales portfolio.*
5) *Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs.*

PSE has firm NWP pipeline capacity to serve our combined-cycle generating plants that require NWP service (Encogen, Freddy 1, Goldendale, and Mint Farm); Sumas is directly connected to Westcoast. All of our simple-cycle combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have backup fuel-oil firing capability and thus do not require firm pipeline capacity on NWP.

Existing gas-for-power supplies. As discussed earlier, 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. Longer-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. We estimate average load requirements for upcoming months and enter into transactions to balance load. PSE balances daily and intra-day positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

Biogas supplies. PSE has purchased biogas from King County's wastewater treatment plant in Renton, Wash. since 1985. The daily output of this plant is approximately 750 Dth per day.

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 is delivered into NWP (which is adjacent to the landfill) and from there to the generating plants. Cedar Hills is expected to supply an average of approximately 3-5 MDth per day of methane.

3. Gas Resource Alternatives

The gas resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

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. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into five broad combinations for analyses. These combinations are illustrated in Figure 6-13. Note that, while not shown, DSR is included in all of the combinations.

- **Combination #1** 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. Gas supplies are also presumed available at the Sumas market hub.

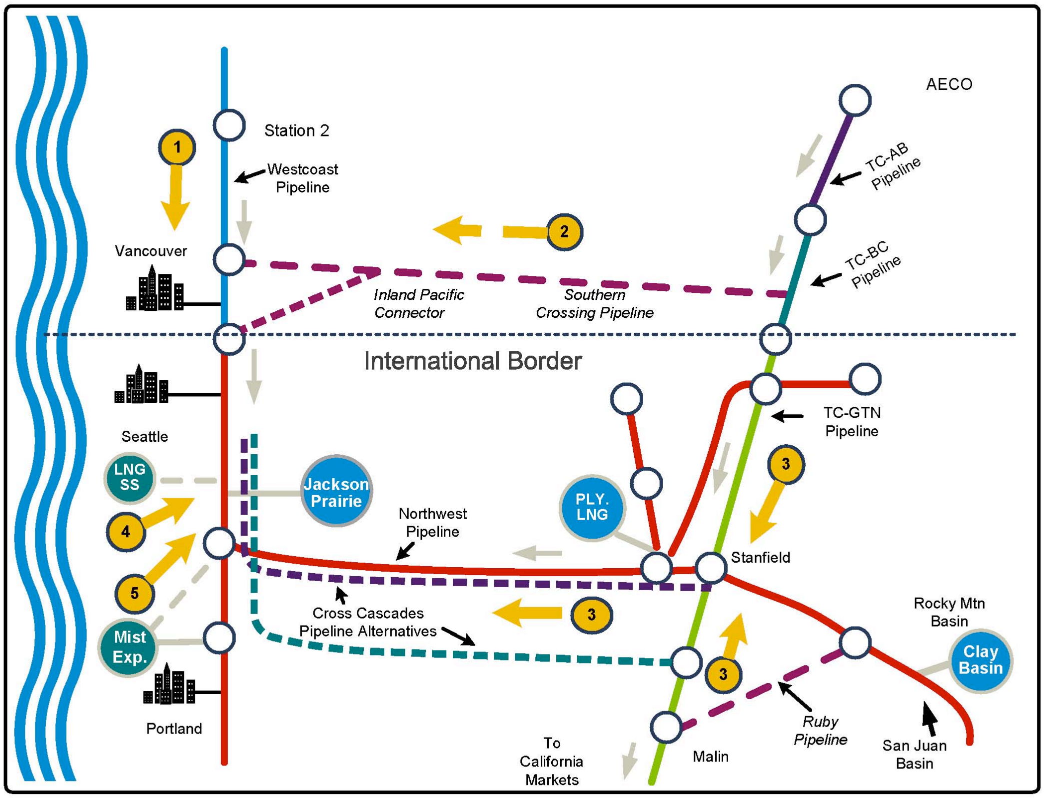
- **Combination #2** represents the Southern Crossing pipeline option. This option would allow delivery of AECO gas to PSE via existing or expanded capacity on the TC-AB and TC-BC pipelines, an expanded Southern Crossing pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

- **Combination #3** provides for deliveries to PSE via a cross-Cascades pipeline. The increased gas supply could either come from of Alberta (AECO hub) via existing or expanded upstream pipeline capacity on the TC-AB, TC-BC, and TC-GTN; or from the Rockies hub on the Ruby pipeline to Malin and onto existing or expanded TC-GTN pipeline capacity with final delivery to PSE via the cross-Cascades pipeline.

- **Combination #4** provides for development of an LNG storage facility in proximity to the existing NWP route and located relatively close to PSE's service territory where it could take advantage of a discounted redelivery service.

- **Combination #5** provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require some expansion of pipeline capacity from Mist to PSE's service territory but is assumed to have discounted redelivery service.

Figure 6-13
PSE Gas Transportation Map Showing Supply Alternatives



Pipeline Alternatives

Direct-connect pipeline capacity alternatives. The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 6-14 below.

Figure 6-14
Direct-connect Pipeline Alternatives Analyzed

Name	Description
NWP - Sumas to PSE city gate	Expansions considered either independently or in conjunction with upstream pipeline/supply expansion alternatives (Southern Crossing or additional Westcoast capacity). Assumed to be available by 2014.
Cross-Cascades – Stanfield/TC-GTN to PSE city gate	Representative of costs and capacity of either an expansion of NWP from Stanfield or the proposed Palomar pipeline with delivery on NWP to PSE city gate. Assumed to be available by 2020.
NWP – Washougal to PSE city gate	Expansion considered in conjunction with a possible lease of expanded 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 Energy's BC Pipeline (Westcoast), which allows us to purchase gas at Station 2 rather than Sumas and take advantage of greater supply availability 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 6-15
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 a 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) bypassing Westcoast facilities upstream of Sumas, or a cooperative arrangement with Westcoast for deliveries from the Southern Crossing pipeline to 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 Spokane and then to the PSE city gate via NWP. The addition of a cross-Cascades pipeline in conjunction with the acquisition of additional capacity on these pipelines would increase access to AECO gas and increase supply diversity.

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, insufficient work has been done with respect to expanding Jackson Prairie to include in this analysis, and additional pipeline capacity from Clay Basin is not available. For this IRP, the company considered the following storage alternatives:

NW Natural Gas Company, 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. Participation in a Mist expansion may require expansion of firm pipeline access to PSE's city gate.

Participation in a regional LNG storage facility is also being considered. 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).

Figure 6-16
Storage Alternatives Analyzed

Name	Description
Expansion of Mist Storage Facility	Based on estimated cost and operational characteristics of expanded Mist storage. Assumes a 15-day supply at full deliverability.
Regional LNG Storage Facility	To be cost effective, such a facility should be located to allow firm delivery to PSE's city gate. The scale of LNG storage implies that joint participation might be attractive. These analyses assume a 10-day supply at full deliverability.

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. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin.

Major pipeline projects have been proposed to transport gas from the Arctic to North American markets, but these projects are too distant and costly to provide short- or medium-term relief. The development of shale gas supplies in the lower 48 states and in Canada and the resulting lower gas prices have pushed these alternatives even further into the future (beyond 2025). The Alaska Natural Gas Transmission System would transport natural gas from the North Slope through Canada to North American markets, including Chicago and the east coast, and provide 4.5 Bcf per day starting between 2024 and 2029. 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.

Figure 6-17
Gas Supply Alternatives Analyzed

Name	Description
Conventional gas supply purchase contracts	Assume current mix of term contracts and spot purchases. Recent estimates of gas reserves indicate that supplies from western Canada and the Rockies will be sufficient to meet needs.

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 ordered 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 resources as quickly as possible.

The acquisition or "ramp rate" of gas sales DSR can be altered by changing the speed with which discretionary measures are acquired. In this IRP, two ramp rates were tested: a 20-year ramp rate (as in past IRPs), and a 10-year ramp rate, which is used in the electric resource analysis.

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/non-weather 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 6-18 illustrates the methodology described above.

Figure 6-19 & 6-20 shows the range of achievable technical potential among the eight 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 A (<$4.5 per Dth) used in the SENDOUT portfolio optimization model for all the bundles with the 10-year ramp rate.

Figure 6-18
General Methodology for Assessing Demand-side Resource Potential

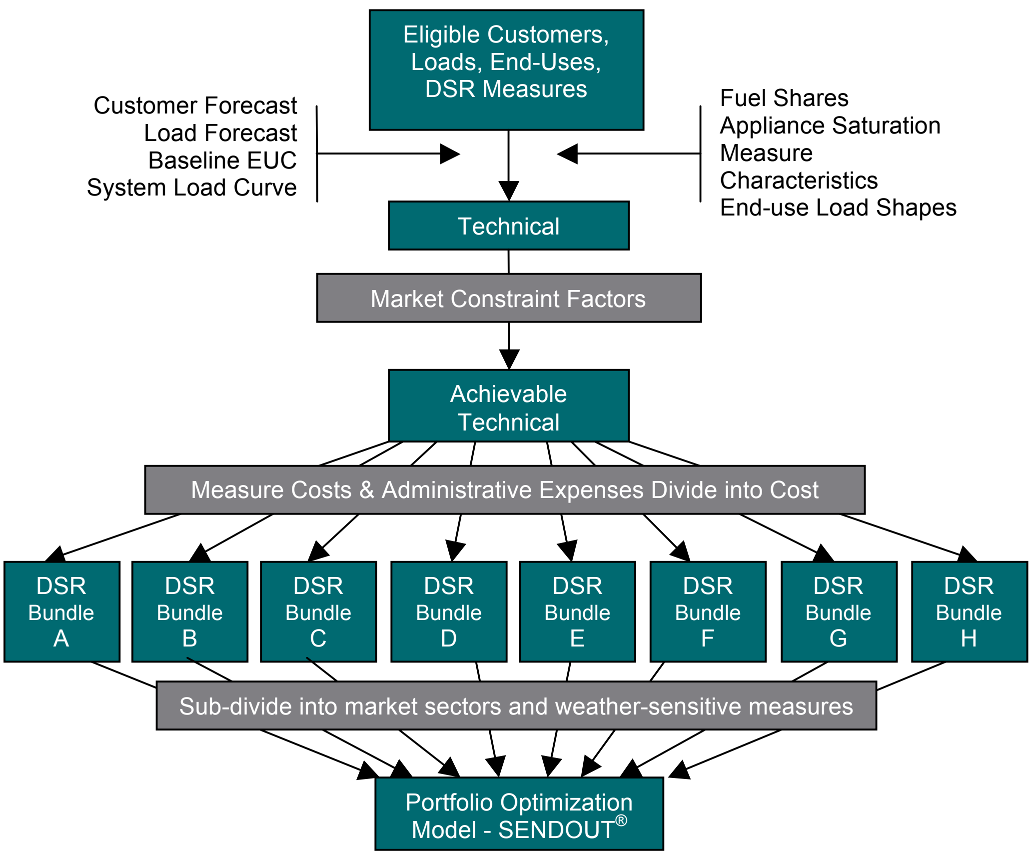


Figure 6-19

Achievable Technical Potential Bundles – 10-year Ramp for Discretionary Measures

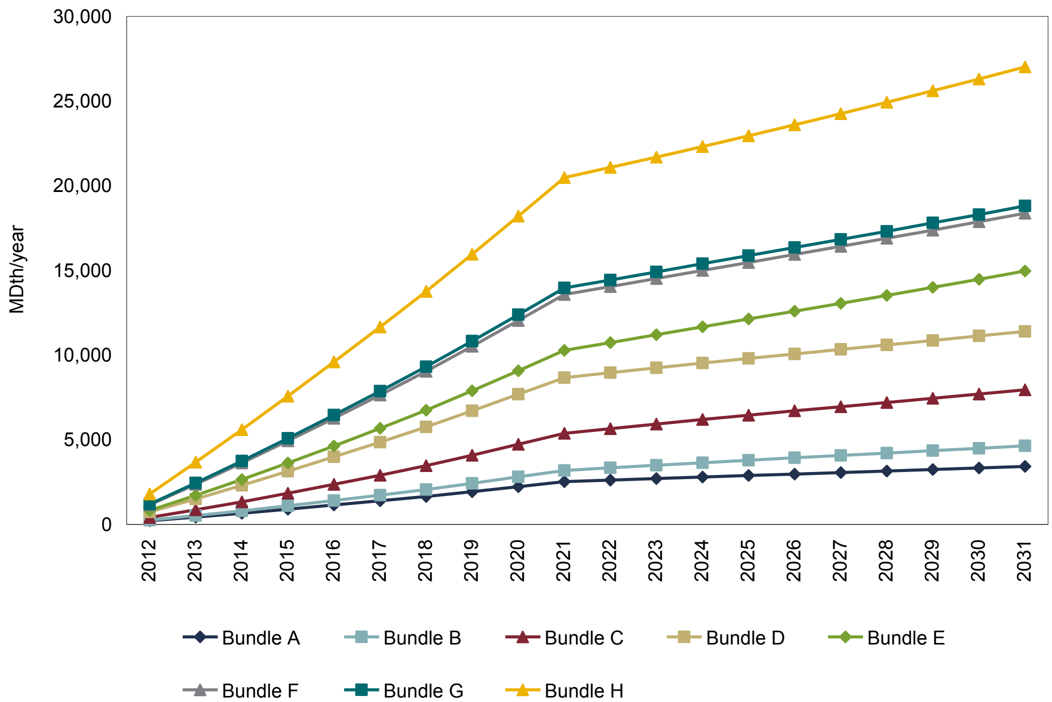


Figure 6-20
Achievable Technical Potential Bundles – 20-year Ramp for Discretionary Measures

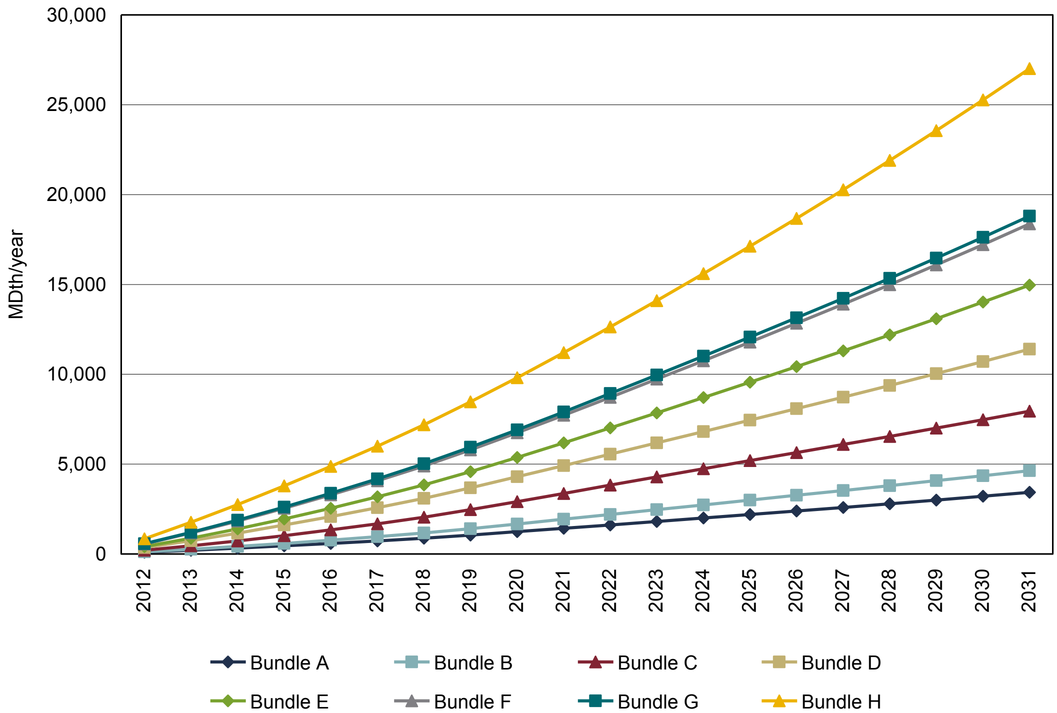
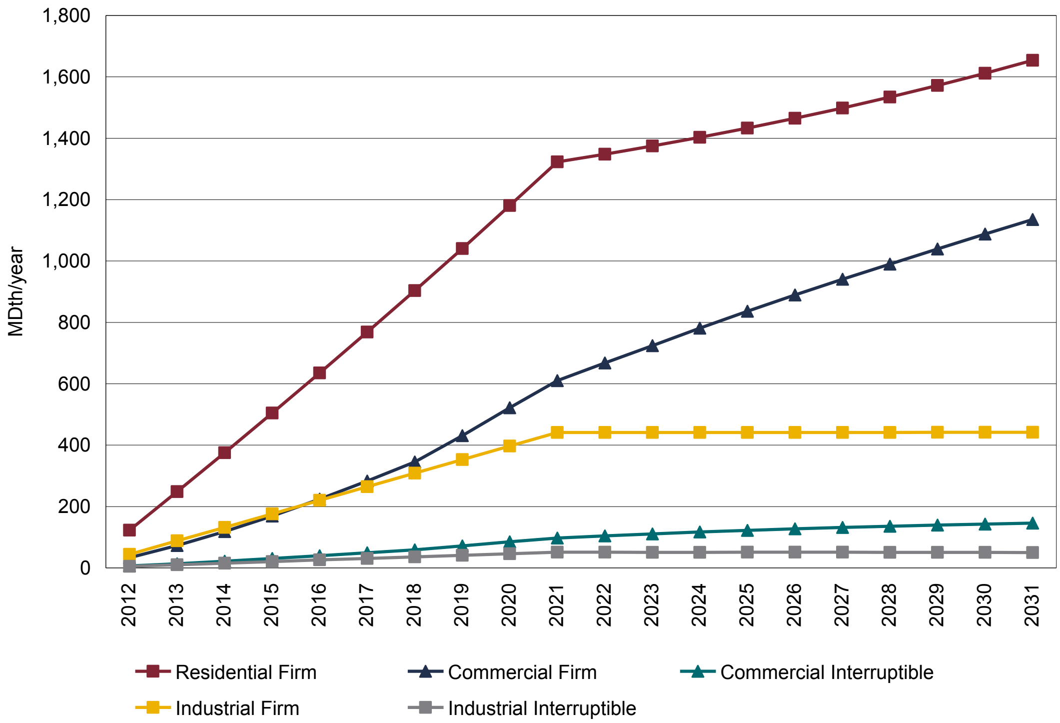


Figure 6-21
Savings Formatted for Portfolio Model Input – Bundle A (($99.00) to $4.50/Dth)



4. 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, scenarios, and sensitivities are explained in Chapter 4.

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. SENDOUT Version 12.5.5, which PSE currently uses, has 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.

Deterministic Optimization Analysis

As described in Chapter 4, PSE developed seven gas sales scenarios and three gas-for-power 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.

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.

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.

5. Gas Analysis Results

For the gas sales portfolio, PSE analyzed seven scenarios. For the combined portfolio (gas sales and gas for power), three sets of circumstances were examined, each with different assumptions regarding the amount of firm gas transport capacity required. Gas sales analysis results are presented first, then the combined portfolio results.

Gas Sales Portfolio Analysis and Results

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.

Demand-side resource additions.

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

We evaluated two DSR program designs for the gas sales portion of this IRP: one with a 20-year ramp rate for discretionary measures, the other with a 10-year ramp rate.

Compared to the 20-year rate, the 10-year ramp rate increased the DSR acquired during the near- and mid-term years, and offset the need for acquisition of some supply-side resources. Both ramp rates resulted in similar amounts of DSR being acquired by 2031. The difference in resource builds that result from the two ramp rates by 2021 are shown in Figures 6-22 and 6-23, respectively.

Figure 6-22

2021 Resource Builds for 20-year Discretionary DSR Ramping

	DSR Total	Cross Cascades Pipeline	Regional LNG Storage	NWP Sumas to PSE Expansion
Base	34	0	20	121
Base + CO2	50	0	0	113
Low Growth	23	0	0	83
High Growth	60	74	22	93
Green World	84	0	0	0
Very Low Gas	11	0	48	121
Very High Gas	60	65	0	45

Figure 6-23

2021 Resource Builds for 10-year Discretionary DSR Ramping

	DSR Total	Cross Cascades Pipeline	Regional LNG Storage	NWP Sumas to PSE Expansion
Base	56	0	0	112
Base + CO2	105	0	0	74
Low Growth	38	0	0	71
High Growth	105	52	0	100
Green World	149	0	0	0
Very Low Gas	21	0	38	121
Very High Gas	105	65	0	9

At 2021, the amount of DSR acquired is noticeably higher with the 10-year ramp rate. In most scenarios, the amount of NWP Sumas to PSE expansion is reduced somewhat and the amount of regional LNG storage is reduced with the 10-year ramping.

Comparing the total portfolio costs of the scenarios assuming the 20-year ramp rate with the scenarios assuming the 10-year ramp rate indicates that the 10-year ramp rate results in a lower NPV in most scenarios. The 20-year ramp rate produces a lower NPV in the Low Growth and the Very Lower Gas Price scenarios. The NPV results are shown in Figure 6-24.

Figure 6-24
Net Present Value Portfolio Costs for Alternative Discretionary DSR Acceleration Rates ($ - millions)

	20-year Ramp Rate	10-year Ramp Rate
Base	10.18	10.16
Base + CO2	12.05	11.98
Low Growth	7.47	7.50
High Growth	13.15	13.06
Green World	15.81	15.64
Very Low Gas Prices	6.09	6.13
Very High Gas Prices	14.12	14.00

Based on these results, the 20-year ramp rate was assumed in the Low Growth and Very Low Gas Price scenarios while the 10-year ramp rate was included in the Base Case and other scenarios.

The optimal portfolio resource additions in each of the seven scenarios are illustrated in Figure 6-25 for 2016, 2020, and 2031.

Figure 6-25
Gas Resource Additions in 2016, 2020 and 2031

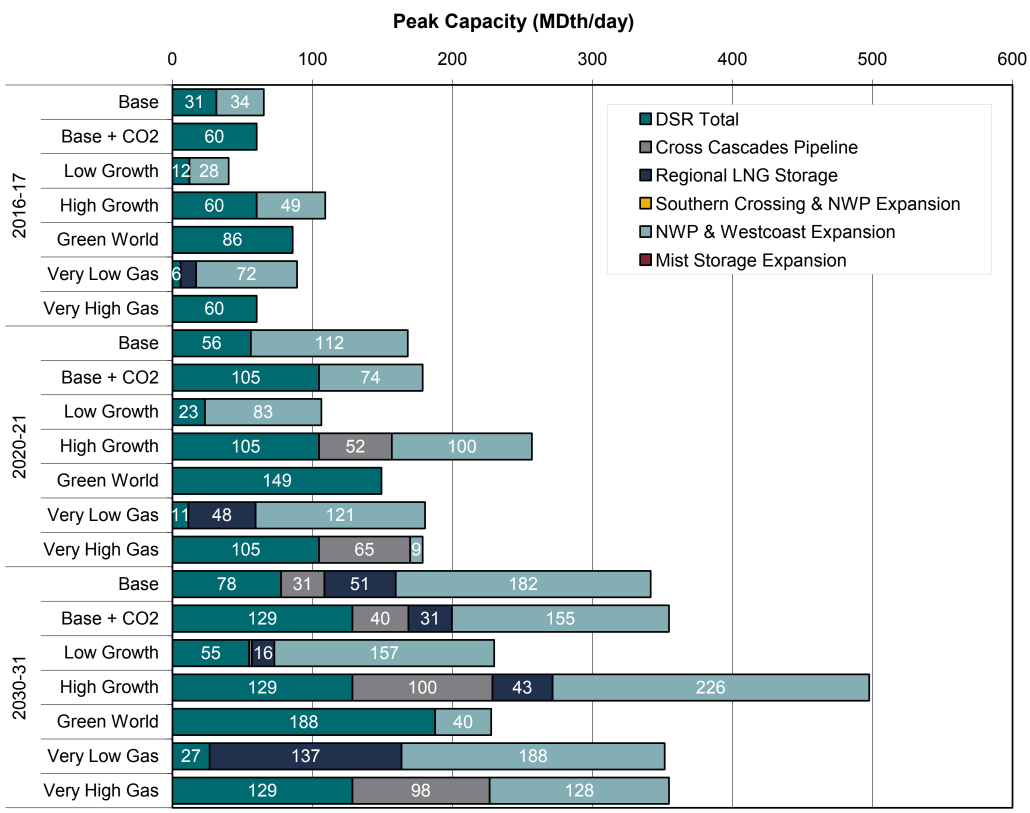
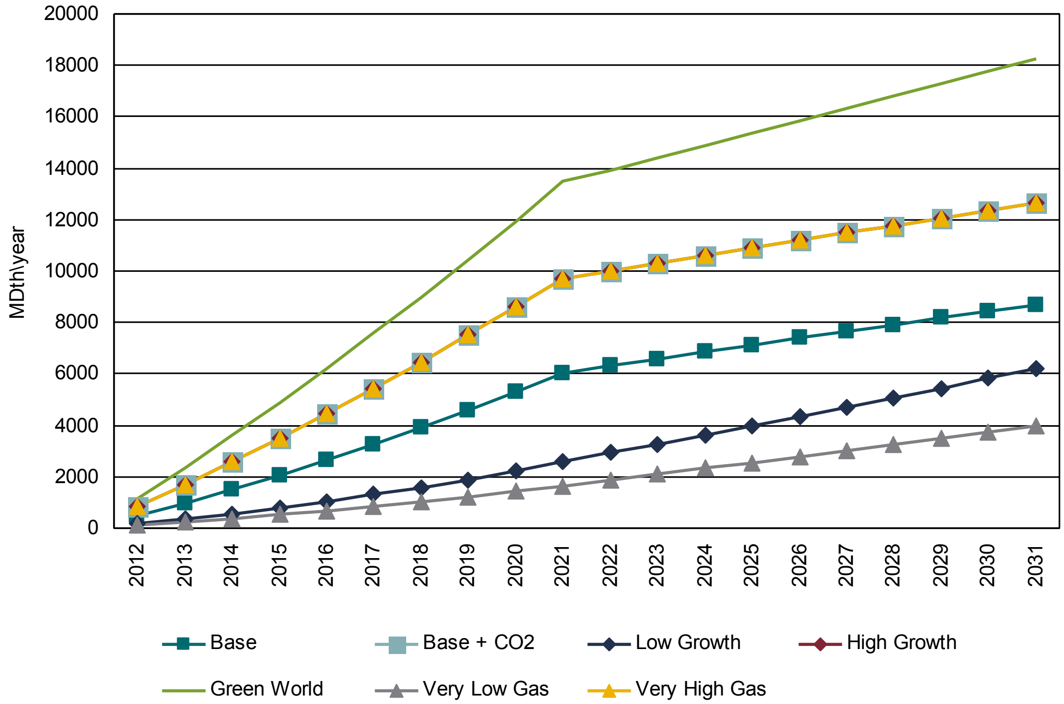


Figure 6-26
Gas Energy Efficiency Savings by Scenario



A downward shift in gas energy efficiency potentials is observable when comparing this IRP with the 2009 plan. This has more to do with changes in assumptions than changes in actual conditions. The 2011 Base Case assumptions do use somewhat lower gas prices than the 2009 Base Case, but CO_2 cost assumptions are much lower than 2009 assumptions. This is the biggest reason for the apparent downward shift. DSR remains very sensitive to avoided costs in the gas analysis. The amount of achievable energy efficiency resources selected by the SENDOUT analysis in this plan ranged from roughly 4,000 MDth in 2031 for the Very Low Gas Price scenario to more than four times that in Green World.

The optimal levels of demand-side resources, selected by market sector in the SENDOUT analysis, are shown in Fig 6-27, below. (For more information on demand-side bundles, see the “Demand-side Resource Alternatives” section in this chapter and Appendix K, Demand-side Resources Analysis.)

Figure 6-27
Gas Sales DSR Bundles by Sector and Scenario

	Base	Base + CO2	Low Growth	High Growth	Green World	Very Low Gas	Very High Gas
Residential Firm Bundle	C	D	B	D	G	A	D
Commercial Firm Bundle	D	F	D	F	F	B	F
Commercial Interruptible Bundle	B	D	A	D	D	A	D
Industrial Firm Bundle	C	E	C	E	E	C	E
Industrial Interruptible Bundle	C	E	C	E	E	C	E

Overall, the economic potential in this IRP is only slightly lower than in the 2009 gas sales Base Case when the 10-year ramp rate is applied.

Figure 6-28 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 savings of 500,000 to 2,300,000 Dth for the 2012-2013 period. The current target for the 2010-2011 period is within this range and the scenarios provide guidance to attain as much cost-effective gas efficiency resources as possible within the constraints of economic and market factors.

Figure 6-28
Short-term Comparison of Gas Energy Efficiency

Short-Term Comparison of Gas Energy Efficiency	Dth
2008-2009 Actual Achievement	880,000
2010-2011 Target (Updated Jan 2011)	980,000
2012-2013 Range of Economic Potential	500,000 – 2,300,000

Supply-side resource additions. As expected, based on lower costs, the predominant supply-side resource addition in all scenarios is the expansion of the Northwest and Westcoast pipelines which increases access to northern B.C. gas supplies. The cross-Cascades alternative is included by 2021 in the High Growth and Very High Gas Price scenario. In these scenarios the relatively higher cost of the cross-Cascades expansion is offset by the difference in prices between Northern B.C. and Rockies supply. The Southern Crossing alternative is not selected in any of the scenarios.

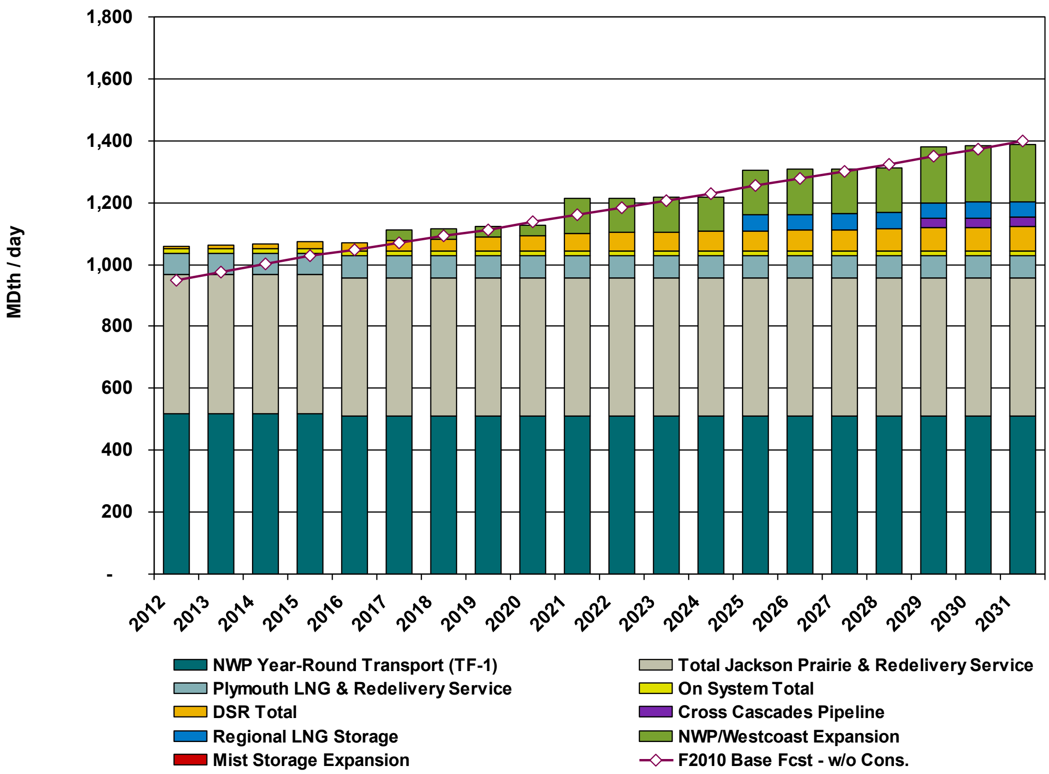
Storage additions. The results indicate that PSE should continue to consider a regionally located LNG storage facility. The Mist Storage alternative was not selected in any of the scenarios due to the cost of pipeline capacity required to redeliver the gas to PSE; discounted transportation capacity could change the conclusion.

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.

Complete Picture: Base Case Scenario

A complete picture of the Base Case scenario optimal resource portfolio is presented below in Figure 6-29. Additional scenario results are included in the Appendix J, Gas Analysis.

Figure 6-29
Base Case Scenario Gas Resource Portfolio



Average annual portfolio cost comparisons.

Figure 6-30 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 6-30

Average Portfolio Cost of Gas for Gas Scenarios

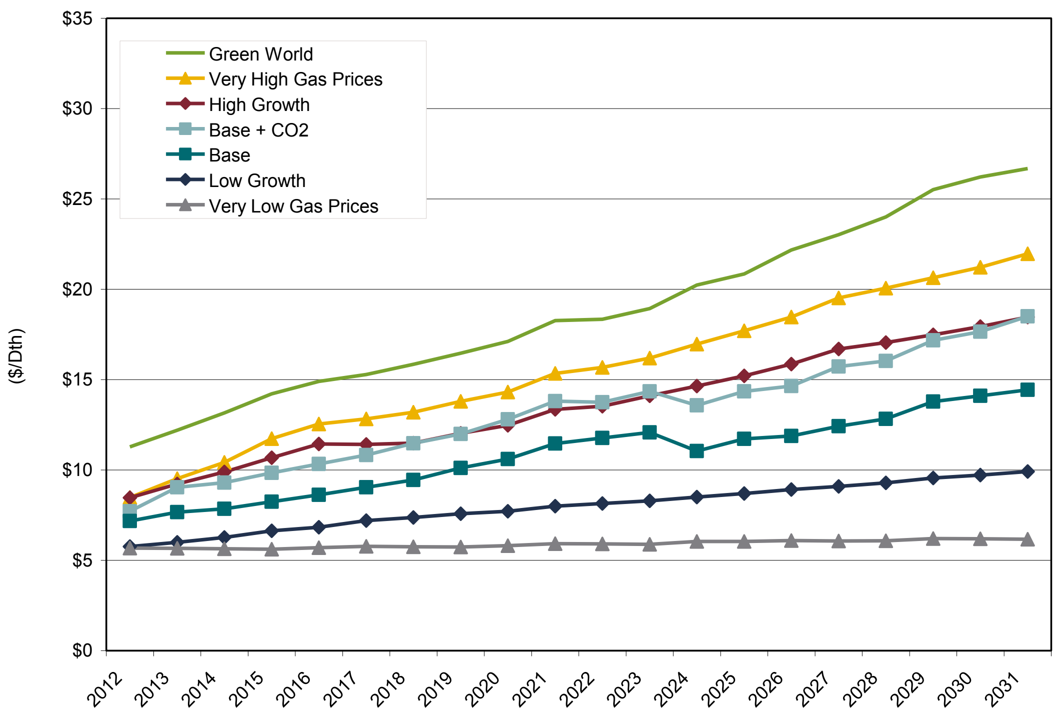


Figure 6-30 shows that average optimized portfolio costs are largely based on the gas price and CO_2 cost assumptions included in each scenario.

- Base Case scenario portfolio costs are about $7.15 per Dth in 2012 and increase to about $14.50 per Dth by 2031.
- The Base + CO_2 scenario costs start at about $7.70 per Dth, but rise to about $18.80 per Dth by 2031. (The only difference from the Base Case is CO_2 emissions cost.)
- The Very Low Gas Price and Low Growth scenarios have the lowest portfolio prices; these reflect lower gas price assumptions and minimal CO_2 costs.
- Green World costs are the highest, reflecting high CO_2 cost assumptions and a high gas price forecast.
- High Growth costs are somewhat lower than the Green World scenario, reflecting minimal CO_2 costs but retaining high gas prices.

Results of Monte Carlo Analysis

Monte Carlo analyses on the Base Case 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 Base Case 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 Base Case scenario. Analyses examined five specific resource addition alternatives: the regional LNG storage alternative, the Southern Crossing/Inland Pacific connector pipeline alternative, the cross-Cascades pipeline alternative, the Mist storage option as well as the various DSR bundles. This discussion compares the results from the deterministic analysis with the results from the Monte Carlo resource optimization analysis.

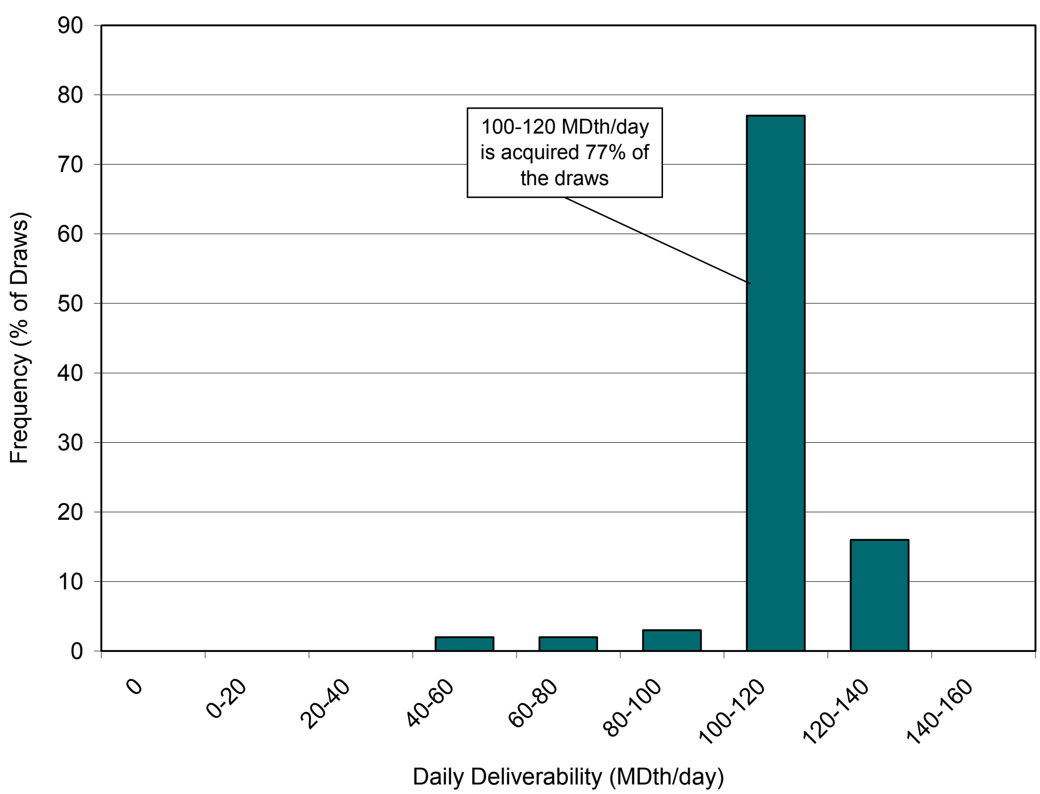
The Monte Carlo results were evaluated to check the resources selected as of January 2017 and January 2021. As of January 2017, essentially all of the Monte Carlo draw resource selections were the same as in the deterministic results. The results of the deterministic analysis was consistent with the stochastic analyses: both selected a mix of

DSR with 31 MDth per day of peak savings and a 34 MDth per day expansion of NWP between Sumas and PSE's service territory.

In January 2021, there is more variation among the Monte Carlo draws. As is the case for 2017, the DSR bundles selected in the deterministic case are essentially the same as in the stochastic results. There are only 2-3 draws with minor differences.

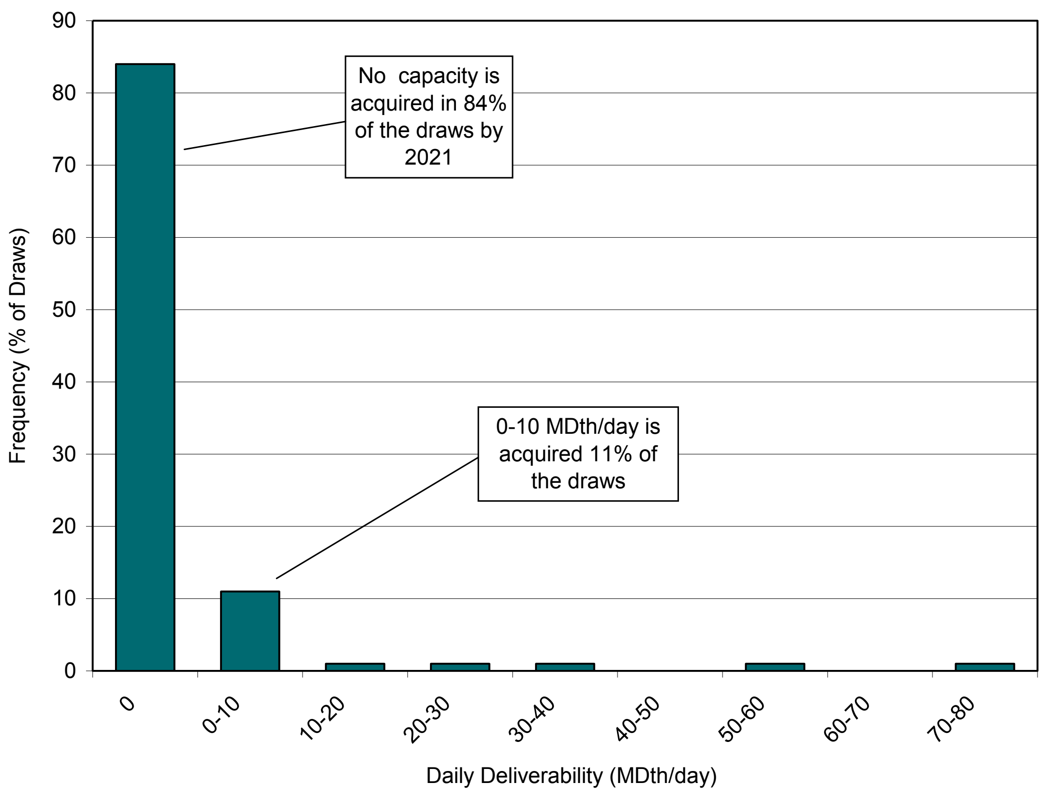
NWP from Sumas to PSE service territory. Figure 6-31 shows the frequency distribution with which the NWP pipeline alternative is selected across the 100 draws by the year 2021. As shown, between 100 and 120 MDth per day of capacity is selected in 77% of the draws. In the deterministic analyses, 112 MDth per day of capacity was selected.

Figure 6-31
Frequency Distribution of NWP Pipeline Development by 2021



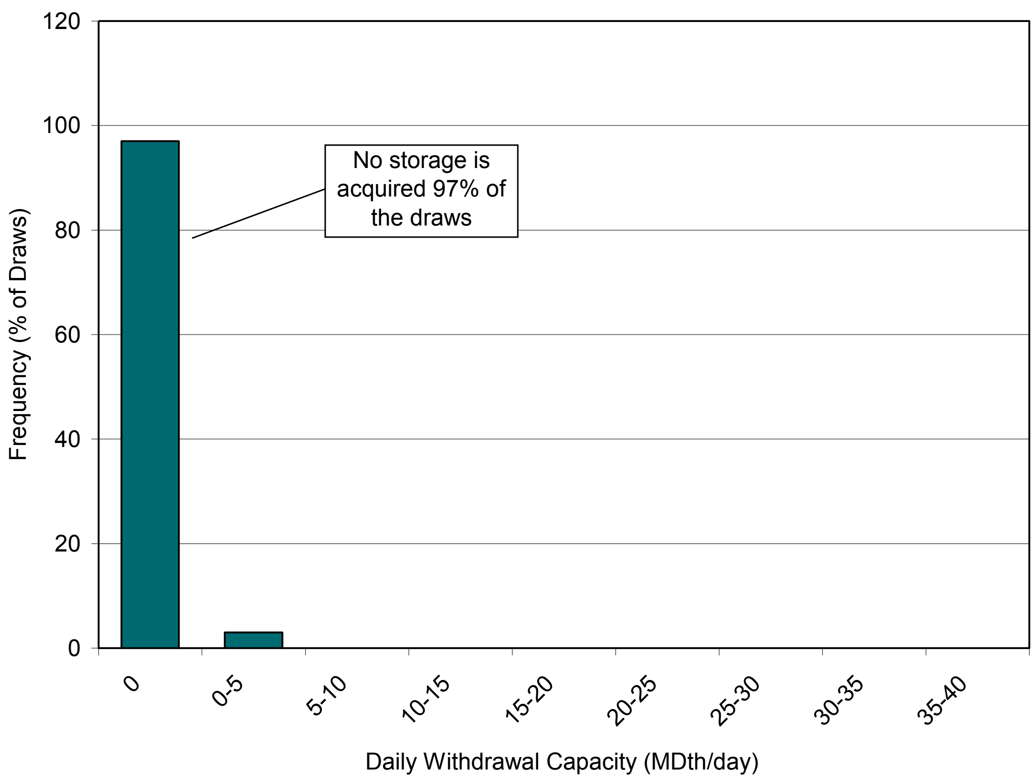
Cross-Cascades pipeline. Figure 6-32 illustrates the frequency distribution for the cross-Cascades pipeline alternative. As shown, in approximately 84% of the Monte Carlo draws, no cross-Cascades pipeline capacity was selected as part of the optimal resource portfolio. Between 10 and 20 MDth per day of capacity was acquired in 11% of the draws. Note that this option was not selected in the deterministic analyses.

Figure 6-32
Frequency Distribution for Cross Cascades Pipeline by 2021



Regional LNG storage. Figure 6-33 shows the frequency distribution for the regional LNG storage alternative. In 97% of the Monte Carlo scenarios, no regional LNG storage capacity was selected. No capacity is included in the deterministic analysis.

Figure 6-33
Frequency Distribution for Regional LNG Storage Development by 2021

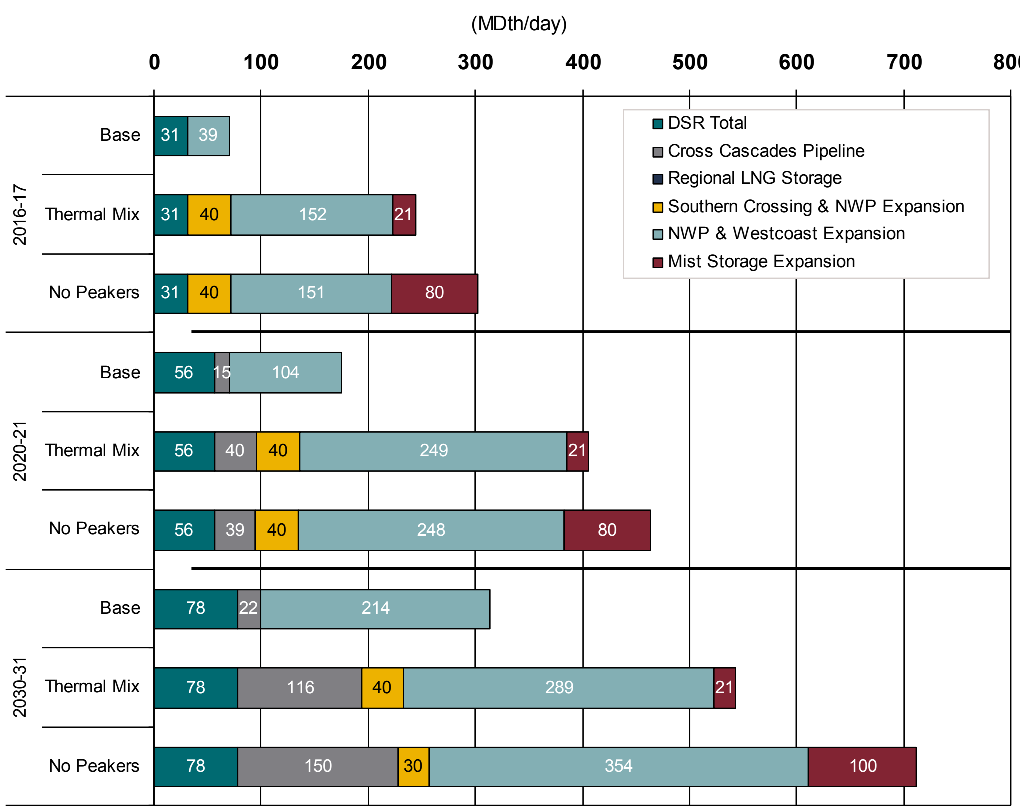


Combined Portfolio Analyses Results

The focus of the combined portfolio analyses was to evaluate the resource additions required to meet the supply needs of the combined gas sales and gas-for-power portfolios. For these analyses three sets of gas-for-power resource builds were modeled in SENDOUT: the Base Case portfolio, the Thermal Mix portfolio, and the No Peakers portfolio. The gas load for each of these was combined with the gas load forecasts from the Base Case gas sales scenario to represent the combined gas portfolio.

The resulting gas portfolio resource additions for each variation for 2017, 2021, and 2031 are shown in Figure 6-34.

Figure 6-34
Combined Portfolio Resource Additions Compared



The quantitative analyses presented in this chapter are based on the results of the SENDOUT 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.

6. 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 provide background information for resource development activities over the next two years.

1. In the Base Case scenario, the gas sales portfolio has adequate resources until the winter of 2015-16.

> Under the High forecast additional resources will be needed by the winter of 2014-15. Under the Low forecast additional resources will not be needed until 2017-18.

2. No firm gas pipeline capacity is needed in any of the electric scenarios. Some additional pipeline capacity may be necessary in later years depending on gas and electric market conditions.

> All new gas-fired generating plants in the electric portfolio developed in this IRP analysis are peakers with oil back-up. Additional firm pipeline capacity or storage may be necessary in the event that an all-peaker portfolio proves to place an unacceptable reliance on day-to-day gas market purchases or non-firm gas pipeline capacity. It also may be prudent to include a combination of peakers and CCCT plants to reduce the reliance on electric market purchases and on non-firm transmission capacity.

3. Continue to investigate the least-cost ramp rates for gas energy efficiency programs.

Experience from the 2010-2011 DSR acquisition programs indicates that accelerated ramp rates are feasible. Accelerating the acquisition of the discretionary measures over 10 years reduces the portfolio costs in the Base Case scenario.

4. The level of DSR varies significantly by scenario.

The level of DSR is sensitive to the gas costs and customer growth rates. DSR economic potential nearly quadruples from its lowest level in the Very Low Gas Price scenario to its highest level in Green World, and this impacts the timing of gas supply side alternatives.

5. Investigate the relative merits of a regional LNG storage facility compared to leasing additional storage from an expanded Mist facility.

Continued expansion of PSE's gas-fired generating resources will increase the need for gas storage resources. Using peakers to address fluctuations caused by wind integration and the need to "level-out" variations in gas loads due to day-to-day changes in power market prices may make additional storage attractive. Both alternatives are included in some of the scenario and sensitivity test results. The two types of storage have different advantages. LNG storage has more flexibility as to location and provides high withdrawal rates, but few days of storage and very low liquefaction (injection) rates; this limits the ability to quickly store gas. Underground storage facilities such as Mist offer much higher injection rates, more days of storage, and reasonably high withdrawal rates, but require longer-haul pipeline capacity.