9 Natural Gas Analysis

This analysis enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

Contents

1. RESOURCE NEED AND DISCUSSION TOPICS

Resource Need

More than 840,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's natural gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).[1] Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the biggest factor in determining load growth at this time is the increase in customer count.[2]

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2021 IRP Mid (Base) Demand Forecast, the 2021 IRP High Demand Forecast and the 2021 IRP Low Demand Forecast.[3]

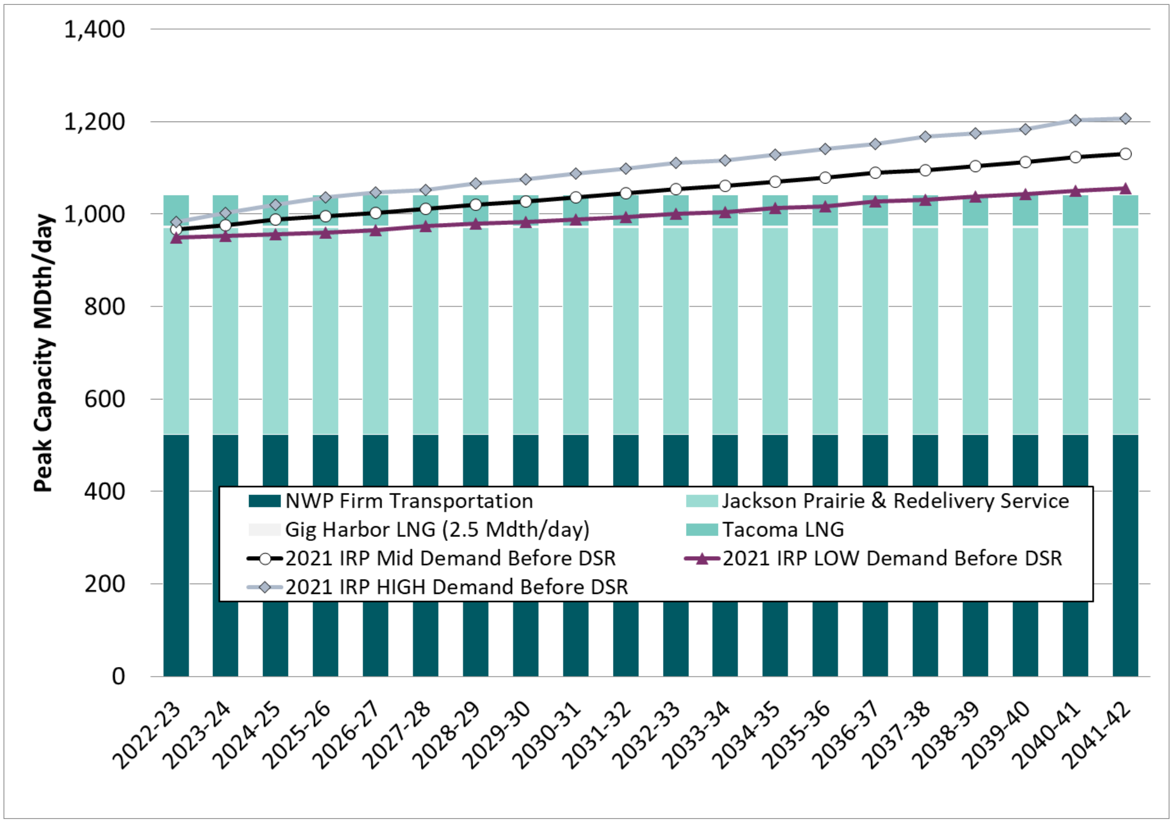
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the Mid Demand Forecast, the first resource need occurs in the winter of 2031-32.
- In the High Demand Forecast, the first resource need occurs immediately.

Figure 9-1 illustrates natural gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 9-2 shows the resource need surplus/deficit for the Mid Demand Forecast.

1 / Heating Degree Days (HDDs) are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.
2 / The 2021 IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.
3 / The 2021 IRP demand forecasts are discussed in detail in Chapter 6, Demand Forecasts.

In Figure 9-1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[4] and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.[5] The gap between demand and existing resources represents the resource need.

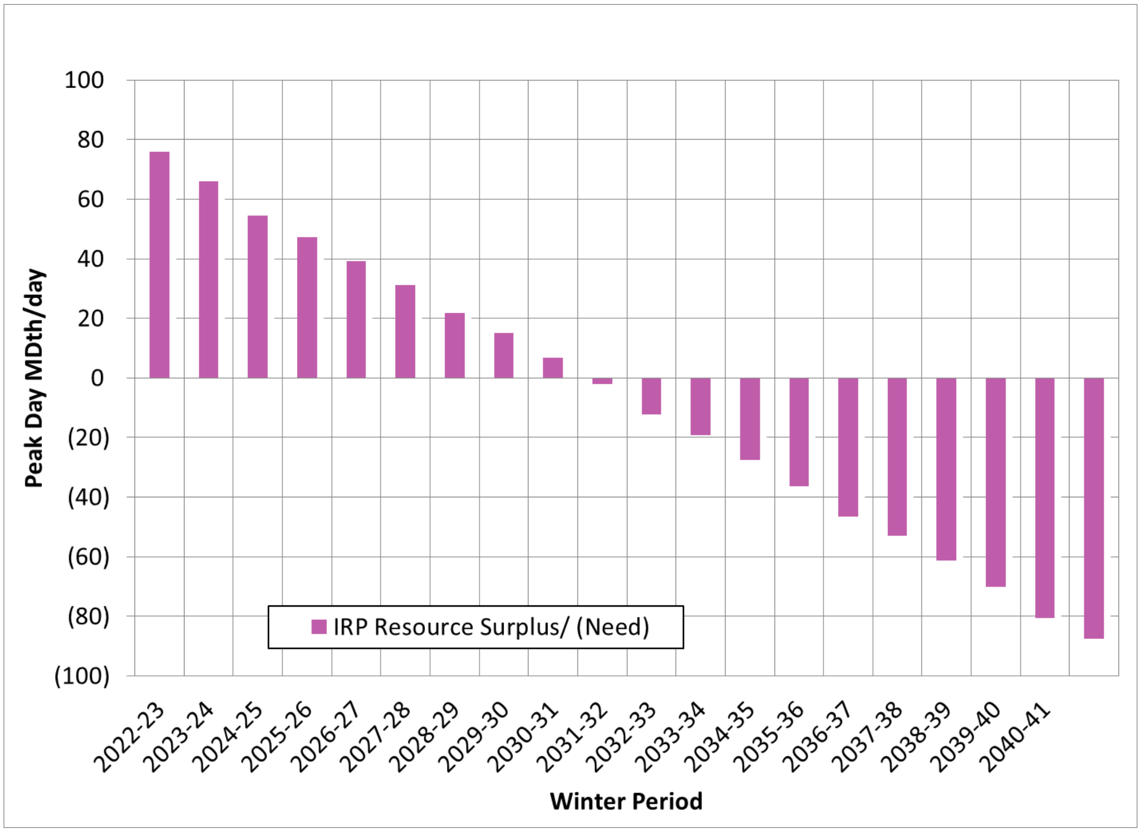
Figure 9-1: Natural Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (meeting need on the coldest day of the year)



4 / *One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of additional conservation savings. Therefore the IRP Natural Gas Demand Forecasts include only DSR measures implemented* ***before*** *the study period begins in 2022. These charts and tables are labeled "before DSR."*

5 / *Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available late in the winter of 2021-22.*

Figure 9-2: Natural Gas Sales Peak Resource Need Surplus/Deficit in Mid Demand Forecast before DSR



Discussion Topics

Infrastructure Reliability

Natural gas transportation and distribution systems are not designed to include the type of redundant capacity that electric distribution systems have because the majority of gas infrastructure is located underground where it is largely insulated from the effects of wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, PSE builds flexibility and resiliency into the system in four ways.

- **A conservative planning standard:** Since PSE's peak day design standard is based on the coldest temperature on record for our service territory, and since this extreme temperature is not often reached and even more rarely sustained, there is some excess capacity in the system on most days.
- **Diverse transport resources:** PSE has built a transport portfolio that intentionally sources natural gas equally from north and south of our service territory to preserve flexibility in the event of supply disruptions. (Approximately 50 percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south.)
- **Natural gas storage:** Including natural gas storage in the portfolio (via Jackson Prairie, Clay Basin, Gig Harbor LNG, and the soon-to-be-completed Tacoma LNG Project) contributes to flexibility and resiliency in several ways. Storage minimizes the need and costs associated with relying on long haul pipelines to deliver gas on cold days; it allows more natural gas to be purchased in the typically less expensive summer season; and it can furnish natural gas supply in the event of a pipeline disruption.
- **Cooperation with regional entities:** Lessons learned from the October 2018 event discussed on the next page were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). Members of the agreement utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest, and they pledge to work together to provide and maintain firm service during emergency conditions and to restore normal service to their customers as quickly as possible after such events occur.

Two incidents illustrate how these strategies work in practice.

A 36-inch pipe on the Westcoast pipeline[6] (Westcoast) between Station 2 and Sumas in central British Columbia (B.C.) ruptured in the early evening of October 9, 2018, shutting off the flow of natural gas from production points in northeast B.C to Sumas for over 30 hours. This resulted in the loss of over 800,000 Dth per day of Sumas supply. Coincidentally, the Jackson Prairie Storage Project was shut down for scheduled maintenance at the time. Coordinating efforts through the Northwest Mutual Assistance Agreement, all the of the natural gas pipelines, utilities, power plant operators and major industrial customers affected worked together to add supply or shed load. Fortis BC, a large downstream utility in southern British Columbia, was able to use some natural gas flowing on its pipeline from Alberta (Southern Crossing), and PSE and other utilities and end-users took steps to reduce natural gas consumption or increase supply from their own on-system storage. These combined efforts prevented a significant loss of pressure in the system, and by 2 p.m. on October 11, 2018 portions of the Westcoast pipeline system were back in service and 38 percent of the normal gas volume from B.C. was flowing. Jackson Prairie personnel worked around the clock to complete the storage facility's planned maintenance ahead of schedule, providing important additional supply to ease the regional situation. Thanks to the combined efforts of Northwest Mutual Assistance participants, the incident lasted less than 48 hours, however, the extensive testing and recertifying required to restore the natural gas flow from B.C. to 100 percent of capacity took over a year. Westcoast was allowed to begin operating its system at 100 percent by mid-November 2019.

In February, 2019, while Westcoast pipeline was still operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced natural gas deliverability by approximately 250,000 Dth per day. The compressor was repaired and back online in less than 30 days, and the net effect of the outage was a reduction in total available storage withdrawals of only 750,000 Dth. Customers experienced no service interruption, but to compensate for the unavailable storage supplies, PSE and other entities that draw natural gas from the storage facility had to purchase additional flowing supply from the market at a time when supply was low and demand, and therefore prices, were high.

These incidents, while quite rare, demonstrate the resilience of the natural gas transportation and storage system in the region. Despite two major failures, no firm residential or commercial customer was without natural gas, nor was there a loss of electrical service, which is increasingly dependent on the natural gas infrastructure. With PSE's current modeling capabilities, it is not possible to model random outages; however, these recent "real-world" experiences demonstrate that the steps taken by PSE to prepare for occasional infrastructure failure have proven successful.

6 / *Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc*

Supply Adequacy

As noted above, PSE intentionally sources natural gas from both north and south of our service territory to preserve flexibility in the event of supply disruptions. Fifty percent of PSE's natural gas supply is sourced from Station 2 and Sumas to the north, and 50 percent from AECO and the Rockies connected to the south. At this time, we are monitoring developments on the Westcoast pipeline that serves the Sumas market.

PSE holds firm capacity on Westcoast's system for approximately 50 percent of its needs from British Columbia in order to access natural gas supplies in the production basin in northern British Columbia rather than only at the Sumas market. This strategy provides a level of reliability (physical access to natural gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

When natural gas production in NE B.C. increased substantially due to the shale revolution, a shortage of pipeline capacity leaving the basin developed as producers sought market outlets for the increased production. For the past several years, Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions); so far, the result has been an adequate supply at Sumas in winter months (when the pipeline is in normal operations) and an excess in summer months.

A 2017 Westcoast capacity offering was fully subscribed, and this will drive construction of facilities to provide an additional 105,000 Dth per day of firm capacity on Westcoast and also 94,000 Dth per day of capacity that was previously held back for maintenance and reliability reasons. The new contracts, totaling 199,000 Dth per day, will bring more firm natural gas to the Sumas hub beginning in November 2021

However, between 2024 and 2027, two new large-volume firm industrial loads totaling over 400,000 Dth per day are expected to come online. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand (from both existing and expansion capacity), they will control their own supply and destiny. Much of the firm pipeline capacity that they will use to access their natural gas supply is currently used to provide the adequate and occasionally abundant supplies at the Sumas market hub to other customers. Once the new customers start up their facilities, they will effectively and dramatically reduce the supply available for other customers at Sumas on most days.

PSE is confident that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2021, and that PSE will still be able to compete (on price) to obtain sufficient supplies in peak periods to fill its existing Northwest Pipeline (NWP) capacity, even when the new industrial concerns begin operations. However, PSE is concerned because the increased demand of 400,000 Dth per day is supported by only 199,000 Dth per day of increased capacity, thus placing price pressure on the remaining supplies.

Because there is currently an equilibrium of firm supply and firm demand in peak winter periods and a surplus in summer periods, PSE believes it is not necessary to secure additional firm Westcoast capacity at this time. However, in the future there is the potential for inadequate capacity to bring sufficient supply to Sumas in peak periods. For this reason, the IRP analysis continues to assume that any new long-term NWP capacity from Sumas used to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast that begins at the supply source in NE B.C.

PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.

2. ANALYTIC METHODOLOGY

Analysis of the natural gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term 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 natural gas resources in a variety of scenarios. Renewal or term extension of existing resources are among the alternatives considered.

Analysis Tools

PSE uses a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and long-term natural gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. 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 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. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them.

***> > > See Appendix I, Natural Gas Analysis Results**, for a more complete description of the SENDOUT gas portfolio model.*

Deterministic Optimization Analysis

PSE developed three natural gas scenarios for this IRP analysis, Mid, High and Low, as shown in Figure 9-3.[7] Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also 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 possible circumstances.

Figure 9-3: 2021 IRP Natural Gas Analysis Scenarios

2021 IRP NATURAL GAS ANALYSIS SCENARIOS				
	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions

NOTE 1. Mid demand corresponds to the 2021 IRP Base Demand Forecast

7 / Chapter 5, Key Assumptions, describes the scenario inputs in detail.

PSE also tested five sensitivities in the natural gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect of a single resource, regulation or condition on the portfolio.

Figure 9-4 2021 IRP Natural Gas Portfolio Sensitivities

2019 IRP NATURAL GAS ANALYSIS SENSITIVITIES		
A	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
B	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
C	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
D	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
E	Temperature Sensitivity on Load	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
F	No DSR	This portfolio will not include any new demand-side resources energy efficiency, distribution efficiency and demand response.

*> > > **See Appendix I, Natural Gas Analysis Results,** for a detailed presentation of scenario and sensitivity analysis results.*

Natural Gas Peak Day Planning Standard

PSE completed a detailed cost-benefit analysis during the 2005 least cost plan (LCP) that is the basis for the current planning standard. That analysis looked at customers' value of reliability of service with the incremental costs of the resources necessary to provide that reliability at various temperatures. Based on the analysis, PSE determined that it would be appropriate to use the 52 HDD (13ºF) as the peak day planning standard.

PSE has used this planning standard since 2005, including in the 2021 IRP. PSE believes that the planning standard is still appropriate in the current environment for the reasons outlined below.

- The standard is based on reliability and safety. In the natural gas sector when there is an outage, it triggers a safety protocol that requires service technicians to physically shut off the gas at the appliance before gas service is restored and make another visit to turn on pilot gas lights. Due to the work hours involved, the outages can take days to weeks to restore during a time when the weather is at its coldest and space heating is an essential service. The existing standard has prevented outages over the last 15 years, and while during this time we have not seen temperatures that approach the design peak day temperature, there is no certainty that we will not see this temperature in the near future.
- When seen in the context of other regional gas utility planning standards, the PSE natural gas planning standard is in line with industry best practices. PSE's implied temperature criteria derived from its planning standard places it in the 98th percentile for annual peaks from 1950 to 2019 (see Figure 9-5), similar to other PNW utilities (see Figure 9-6).

Figure 9-5: PSE Planning Standard Implied Temperature Criteria

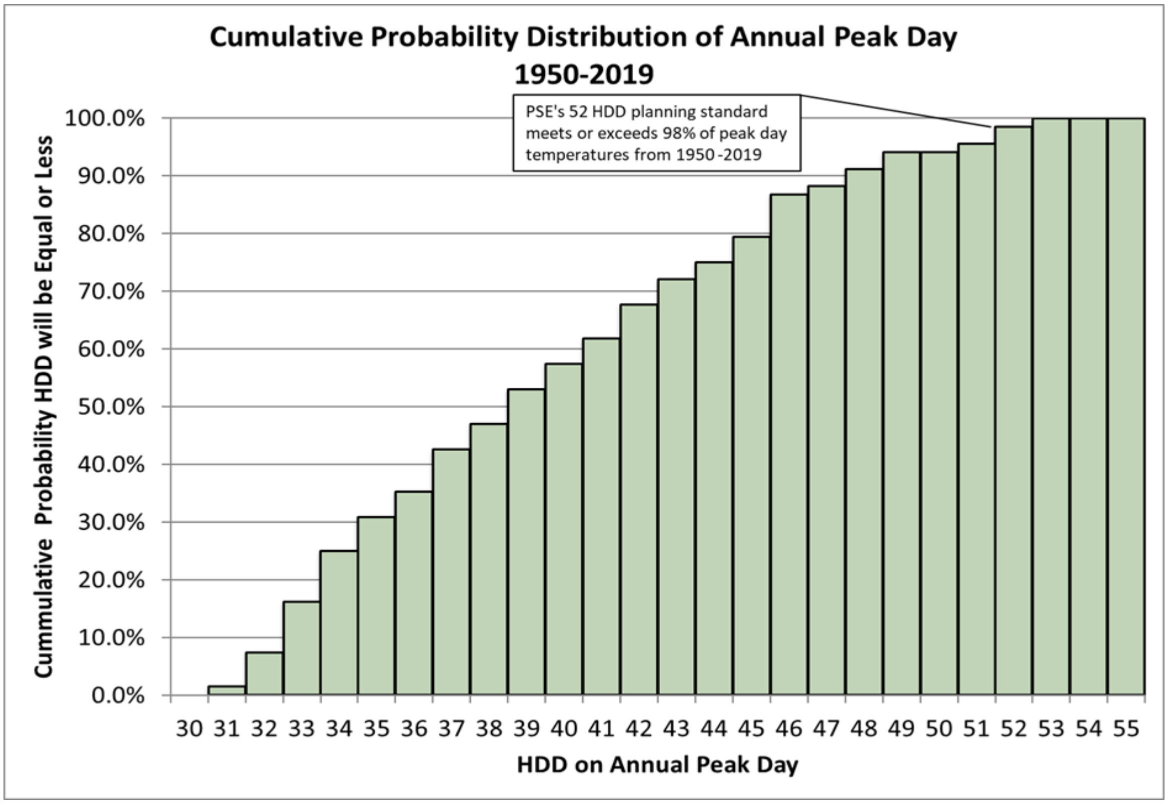


Figure 9-6: Pacific Northwest Natural Gas Utility Planning Standards

PNW Gas Utility	Peak Capacity Design Standard
NW Natural	NW Natural will plan to serve the highest firm sales demand day in any year with 99% certainty: 99th percentile of annual peak days over last 100 years.
Cascade Natural	Coldest day during the past 30 years.
Avista Corp	Adjust the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days on either side of the coldest day to temperatures slightly warmer than the coldest day.
Fortis NG	1 in 20 years temperature based on annual peak days over last 60 years.
PSE	98th percentile of annual peak days from 1950-2019

Natural gas ignition technology has not changed much in the last 15 years. Penetration of electronic ignition is still very small, so service personnel are still required to relight homes in the event of an outage. The cost of relighting has also increased since the 2005 study due to increased population density and travel times in the region.

The results of the 2021 IRP analysis show that lower demand, which may result from a revised peak day planning standard, will likely not change the resource alternatives needed to serve future loads. Even in the Low Scenario, the natural gas portfolio model selected the same level of cost-effective conservation as the High Scenario. Thus, revising the planning standard would not change the results of the analysis in the 2021 IRP.

Given that the PSE planning standard is in line with peer natural gas utilities, has provided a reliable natural gas system, and will not result in any material change to the resource alternatives chosen in the analysis, PSE believes it is appropriate to use the 52 HDD peak day planning standard in the 2021 IRP. PSE plans to study the impacts of changing the planning standard.

3. EXISTING RESOURCES

Existing natural gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, natural gas supplies and demand-side resources.

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 natural gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

All natural gas delivered to our distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of firm capacity with NWP.

- 542,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) and the San Juan Basin. This provides valuable flexibility, including the ability to source natural gas from different regions on a day-to-day basis in some contracts.

Upstream Pipeline Capacity

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

A schematic of the natural gas pipelines for the Pacific Northwest region is provided in Figure 9-7. For the details of PSE's natural gas sales pipeline capacity, see Figure 9-8.

Figure 9-7: Pacific Northwest Regional Natural Gas Pipeline Map

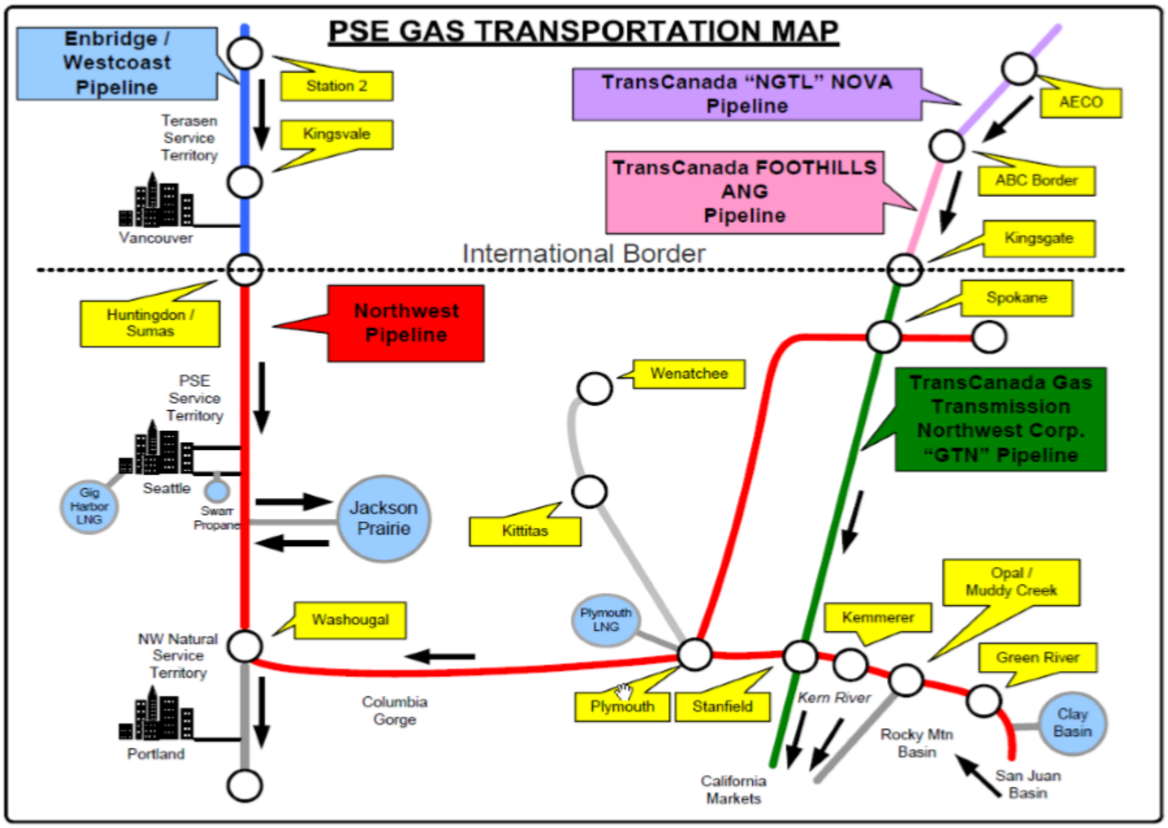


Figure 9-8: Natural Gas Sales - Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Direct-connect				
NWP/Westcoast Interconnect (Sumas)	1	287,237	135,146	152091
NWP/TC-GTN Interconnect (Spokane)	1	75,936	-	75,936
NWP/various in US Rockies & San Juan Basin	1	179,699	52,423	127,276
Total TF-1		**542,872**	**187,569**	**355,303**
NWP/Jackson Prairie Storage Redelivery Service	1,2	447,057	444,184	2,873
Storage Redelivery Service		**447,057**	**444,184**	**2,873**
Total Capacity to City Gate		**989,929**	**631,753**	**358,176**

Pipeline/Receipt Point			Year of Expiration	
	Note	Total	2023-28	2028+
Upstream Capacity				
TC-NGTL: from AECO to TC-Foothills Interconnect (A/BC Border)	3	79,744	79,744	-
TC-Foothills: from TC-NGTL to TC-GTN Interconnect (Kingsgate)	3	78,631	78,631	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Spokane)	4	65,392	65,392	-
TC-GTN: from TC-Foothills Interconnect to NWP Interconnect (Stanfield)	4,5	11,622	11,622	-
Westcoast: from Station 2 to NWP Interconnect (Sumas)	6,7	135,795	135,795	-
Total Upstream Capacity	**8**	**371,184**	**371,184**	**-**

NOTES

1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.

2. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; 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. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.

5. Capacity can alternatively be used to deliver additional volumes to Spokane.

6. Converted to approximate Dth per day from contract stated in cubic meters per day. Westcoast has adjusted the heat content factor upward to reflect the higher Btu gas now normal on its system. The effect is to allow customers to transport more Btu in the same contractual capacity.

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.

Transportation Types

TF-1

TF-1 transportation contracts are "firm" contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport natural gas every day.

Storage Redelivery Service

PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Primary Firm, Alternate Firm and Interruptible Capacity

FIRM TRANSPORTATION CAPACITY carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of natural gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported. Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point.

ALTERNATE FIRM CAPACITY occurs when firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. This "alternate firm capacity" can be very reliable if the contract is used to flow natural gas within the primary path; that is, in the contractual direction to or from the primary delivery or receipt point. Alternate firm is much less reliable or predictable if used to flow natural gas in the opposite direction or "out of path." While "out of path" alternate firm capacity has higher rights than non-firm, interruptible capacity, it is not considered reliable in most circumstances.

INTERRUPTIBLE CAPACITY on a fully contracted pipeline can become available if a firm shipper does not fully utilize its firm rights on a given day. This unused (interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rate for interruptible capacity is negotiable and typically billed as a variable charge. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport natural gas on an alternate basis, outside of their contracted firm transportation path.

The flexibility to use firm transport in an alternate firm manner "within path" or "out of path," along with the ability to create "segmented release" capacity, has resulted in very low non-firm, interruptible volumes on the NWP system.

When capacity is not needed to serve natural gas customers on a given day, PSE may use its firm capacity to transport natural gas from a low-priced basin to a higher-priced location and resell the gas to third parties to recoup a portion of demand charges. When PSE has a surplus of firm capacity and market conditions make such transactions favorable for customers, PSE may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market on a temporary or permanent basis when it is available and competitive with other alternatives.

Interruptible service plays a limited role in PSE's resource portfolio because of the flexibility of the company's firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

Natural gas storage capacity is a significant component of PSE's natural gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm natural gas supply or storage space 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 purchase and store natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- PSE also uses storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area that is designed to deliver large quantities of natural gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Figure 9-9 presents details about storage capacity.

Figure 9-9: Natural Gas Sales Storage Resources[1] as of 11/1/2020

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie – PSE Owned	398,667	147,333	8,528,000	N/A
Jackson Prairie – PSE Owned [2]	(50,000)	(18,500)	(500,000)	2023
Net JP Owned	**348,667**	**128,833**	**8,028,000**	
Jackson Prairie – NWP SGS-2F [3]	48,390	20,404	1,181,021	2023
Net Jackson Prairie	**397,057** [5]	**149,237**	**9,209,021**	
Clay Basin [4]	107,356	53,678	12,882,750	2023
Net Clay Basin	**107,356**	**53,678**	**12,882,750**	
Total	**504,413** [6]	**202,915**	**22,091,771**	

NOTES
1. Storage, injection and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2. Storage capacity made available to PSE's electric generation portfolio (at market-based price) from PSE natural gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve natural gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. PSE expects to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for a total of 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

Jackson Prairie Storage

As shown in Figure 9-9, PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates under FERC authorization. PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve natural gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm storage capacity through an SGS-2F storage service contract with NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core natural gas 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.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores natural 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 service.

PSE uses 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. Natural gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP 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 natural 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 the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

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

Figure 9-10: Natural Gas Sales Peaking Resources

	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Transportation Tariff	Availability
Gig Harbor LNG	2,500	2,500	10,500	On-system	current
Swarr LP-Air [1, 2]	30,000	16,680	128,440	On-system	Nov. 2024+
Tacoma LNG [3]	69,300	2,100	538,000	On-system	Mar. 2021
TOTAL	**101,800**	**21,280**	**676,940**		

NOTES
1. Swarr is currently out of service pending upgrades to reliability, safety and compliance systems. It may be considered in resource acquisition analysis for an in-service date of November 2024 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons per minute, it takes 7.7 days to refill, or 16,680 Dth per day.
3. Planned in-service date is Mar. 1, 2021. Withdrawal (vaporization) capacity will rise in the future when the distribution system is upgraded. Such a distribution system upgrade – allowing an increase of 16,000 Dth per day in LNG vaporization – is considered as a potential new resource in this IRP.

Gig Harbor LNG

Located in the Gig Harbor area of the Kitsap Peninsula, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's 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 its 2.5 MDth per day capacity 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 natural 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 natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's natural gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility's environmental, safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP in Combination #7 – Swarr LP-Air Upgrade, and is assumed to be available on three years' notice as early as the 2023/24 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak shaving facility to serve the needs of core natural gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core natural gas customers. This LNG peak-shaving facility is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2021 IRP assumes the project is put into service late in the 2020-21 heating season, providing 69 MDth per day of capacity – 50 MDth per day of vaporization and 19 MDth per day of recalled natural gas supply. The full 85 MDth per day of capacity will become available when additional upgrades to the natural gas distribution system allow vaporization of an additional 16 MDth per day; this additional capacity is assumed to be available as a new resource on three years' notice beginning in the 2024/25 heating season.

Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to natural 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 natural 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 some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta. PSE's pipeline capacity on NWP currently provides for 50 percent of our flowing natural gas supplies to be delivered from north of our service territory and the remaining 50 percent from south of our service territory.

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, operational challenges or high local demands. This separation cycle can last several years, but is often alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in transportation costs and forecasted demand increases. The long-term supply pricing scenarios used in this analysis were provided by Wood-Mackenzie, whose North American supply/demand model considers the non-synchronized cyclical nature of growth in production, demand and infrastructure development to forecast monthly pricing in the supply basins accessed by PSE pipeline capacity.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal, Clay Basin and Blanco. Alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as 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, TransCanada's Nova (TC-NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Natural gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months. PSE estimates average load requirements for upcoming months and enters into month-long or multi-month transactions to balance load. Daily positions are balanced using storage from Jackson Prairie, Clay Basin, day-ahead purchases and off-system sales transactions; intra-day positions are balanced using Jackson Prairie. PSE monitors natural gas markets continuously to identify trends and opportunities to fine-tune our contracting, purchasing and storage strategies.

Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.[8] These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[9] Through 1998, the programs primarily served residential and low-income customers; in 1999, they were expanded to include commercial and industrial customer facilities. The majority of natural gas energy efficiency programs are funded using gas "rider" funds collected from all customers.

Figure 9-11 shows that energy efficiency measures installed through 2019 have saved a cumulative total of over 5.4 million Dth, which represents a reduction in CO_2 emissions of approximately 324,000 metric tons – more than half of this amount has been achieved since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million therms in 2013.

Energy savings targets and the programs to achieve those targets are established every two years. The 2018-2019 biennial program period concluded at the end of 2019. The current program cycle runs from January 1, 2020 through December 31, 2021 and has a two-year energy savings target of approximately 8 million therms. 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 and Integrated Resource Plan Advisory Group.

PSE spent over $17.5 million for natural gas conservation programs in 2019 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is collaborating with regional efforts to find creative ways to make delivery and marketing of natural gas efficiency programs more cost-effective, and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

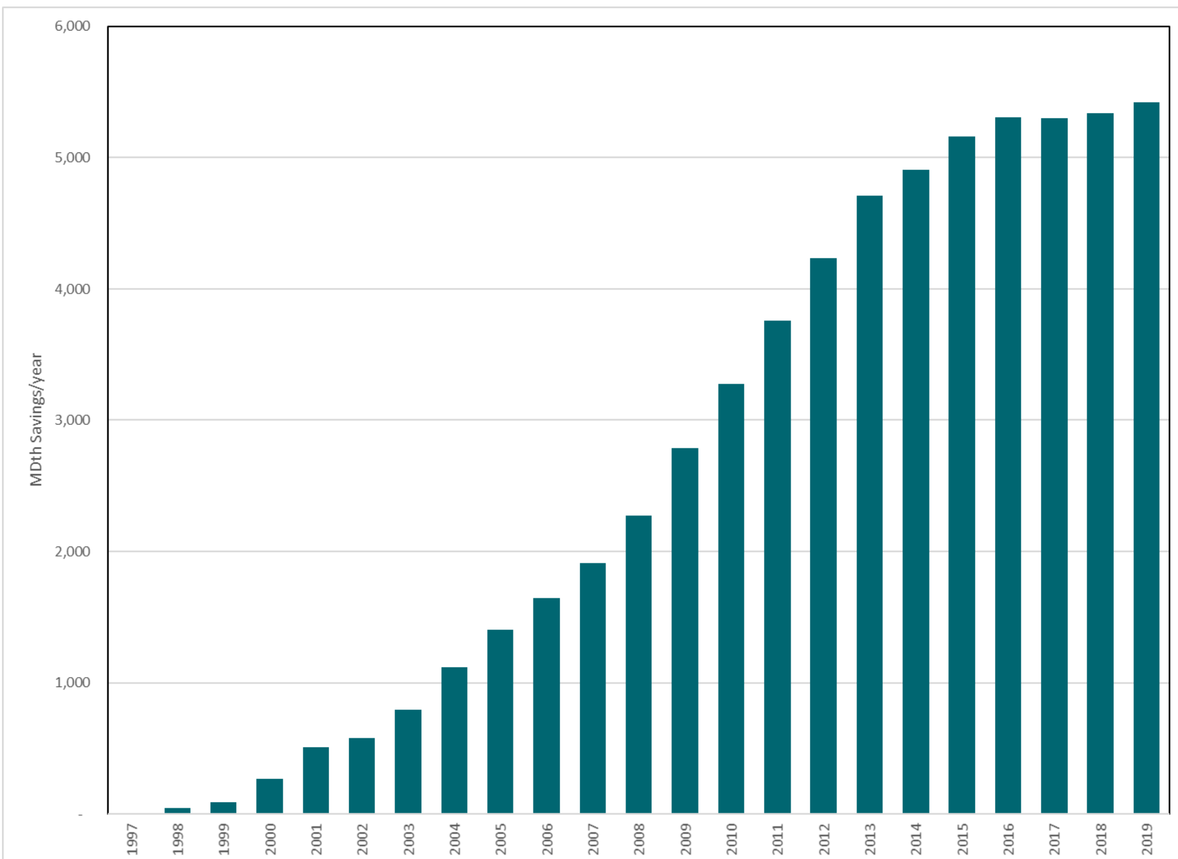
Figure 9-11 summarizes energy savings and costs for 2018 through 2021.

8 / Demand-side resources, also called conservation, contribute to meeting resource need by reducing demand.
9 / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.

Figure 9-11: Natural Gas Sales Energy Efficiency Program Summary, 2018 – 2021
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2018	377.1	15.8	327	15.3
2019	322.8	17.7	314.7	15.9
2020-21			795.3	34.5

Figure 9-12: Cumulative Natural Gas Sales Energy Savings from DSR, 1997 – 2019



4. RESOURCE ALTERNATIVES

The natural gas sales 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 natural gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and natural 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 seven broad combinations for analysis purposes. These combinations are discussed below and illustrated in Figure 9-13. Note that demand-side resources is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

- AECO: the Alberta Energy Company trading hub, also known as Nova Inventory Transfer (NIT)
- LP-Air: liquid propane-air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TransCanada-Foothills BC (Zone 8) pipeline
- TC-GTN: TransCanada-Gas Transmission-Northwest pipeline
- TC-NGTL: TransCanada-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Westcoast Energy Inc. pipeline

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2023, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that might be available to be contracted to meet PSE needs from November 2022 to October 2025 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated to begin no earlier than November 2025. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) natural gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE. As a major greenfield project, this resource option is dependent on significant additional volume being contracted by other parties.

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Ore. to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Ore. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

This option involves PSE leasing storage capacity from NW Natural Gas after an expansion of the Mist storage facility. Pipeline capacity from Mist, located in the Portland area, would be required for delivery of natural gas to PSE's service territory, and the expansion of NWP pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracted by other parties. Mist expansion and a NWP southbound expansion – which would facilitate a lower-cost northbound storage redelivery contract – are not expected to be available until at least November 2025.

Combination # 5 – Plymouth LNG with Firm Delivery

This option includes 70.5 MDth per day firm Plymouth LNG service and 15 MDth per day firm NWP pipeline capacity from the Plymouth LNG plant to PSE. Currently, PSE's electric power generation portfolio holds this resource, which may be available for renewal for periods beyond April 2023. While this is a valuable resource for the power generation portfolio, it may be a better fit in the natural gas sales portfolio.

Combination # 6 – LNG-related Distribution Upgrade

This combination assumes completion of the LNG peak-shaving facility, providing 69 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, which would allow an additional 16 MDth per day of vaporized LNG to reach more customers. In effect, this would increase overall delivered supply to PSE customers, since natural gas otherwise destined for the Tacoma system would be displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

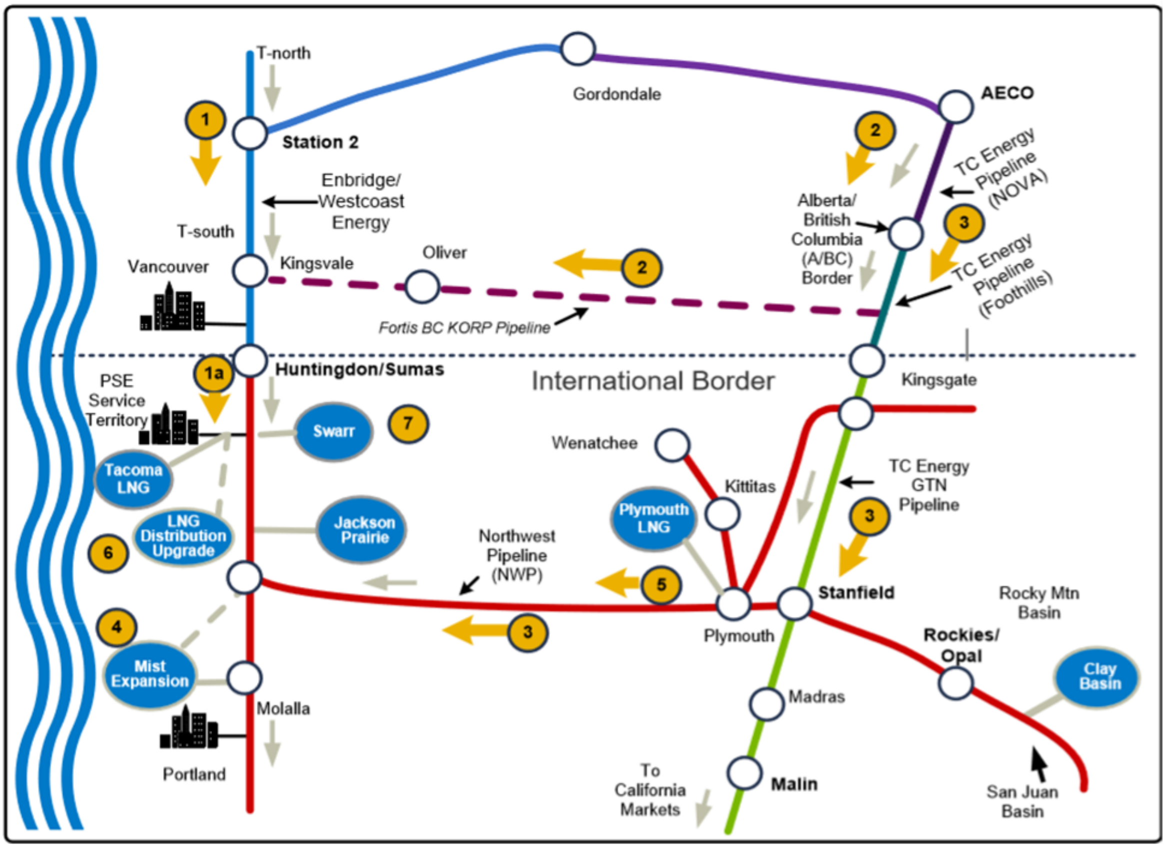
Combination # 7 – Swarr LP-Air Upgrade

This is an upgrade to the existing Swarr LP-Air facility discussed above. The upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network, and could be available on three years' notice as early as winter 2024-25.

NOTE: Combinations 2, and 4 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the natural gas sales resource alternatives is depicted in Figure 9-13 below.

Figure 9-13: PSE Natural Gas Transportation Map Showing Supply Alternatives



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 9-14 below.

Figure 9-14: Direct-connect Pipeline Alternatives Analyzed

Direct-connect Pipeline Alternatives	Description
NWP - Sumas to PSE city gate *(from Combinations 1 & 2)*	Expansions considered in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2025.
NWP – Portland area to PSE city gate *(from Combination 4)*	Expansion considered in conjunction with storage expansion alternatives (Mist storage capacity) assumed available after November 2025.

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying natural 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 supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast (Westcoast Energy's B.C. pipeline), which allows PSE to purchase natural gas at Station 2 rather than Sumas and take advantage of greater supply diversity availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase natural gas directly from suppliers at the very liquid AECO/NIT trading hub and transport it to the existing interconnect with NWP and its proposed Cross-Cascades upgrade on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.

Figure 9-15: Upstream Pipeline Alternatives Analyzed

Upstream Pipeline Alternatives	Description
Increase Westcoast Capacity (Station 2 to PSE) *(from Combination 1)*	Acquisition of new Westcoast capacity is considered to increase access to natural gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas.
Increase TransCanada Pipeline Capacity (AECO to Madras or Stanfield) *(from Combination 3)*	Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT natural gas to Madras for connection to the TC Cross-Cascades project and a separate northbound upgrade of NWP or to Stanfield for delivery to PSE city gate via the proposed NWP Cross Cascades upgrade. Assumed availability no earlier than November 2025.
Kingsvale-Oliver Reinforcement Project (KORP) *(from Combination 2)*	Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of new capacity on the TC-NGTL and TC-Foothills pipelines. Available no earlier than November 2025.

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia, which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.

Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2025. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2025, once the Mist upgrade is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter-only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because natural gas otherwise destined for the Tacoma system is displaced by vaporized LNG and therefore available for delivery to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on three years' notice starting as early as winter 2024-25.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated while PSE is in the preliminary stages of designing the upgrade to Swarr's environmental, safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available on three years' notice for the 2024-25 heating season or beyond.

Figure 9-16: Natural Gas Storage Alternatives Analyzed

Storage Alternatives	Description
Expansion of Mist Storage Facility *(Combination 5)*	Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2025-26 heating season. (Requires incremental pipeline capacity.)
Distribution upgrade allowing greater utilization of Tacoma LNG *(Combination 7)*	Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG peak-shaving beginning the 2024-25 heating season.
Swarr LP-Air Facility Upgrade *(Combination 8)*	Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2024-25 heating season.
Plymouth LNG contract with NWP firm transportation *(Combination 6)*	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2023.

Natural Gas Supply Alternatives

Conventional Natural Gas

As described earlier, natural 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 natural gas supplies will be available to support pipeline expansion from northern British Columbia via Westcoast or TC-NGTL,TC-Foothills and TC-GTN or from the Rockies basin via NWP.

Renewable Natural Gas (RNG)

Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

HB 1257 passed the Washington State legislature and became effective in July, 2019; it was also incorporated in the WUTC RNG Policy Statement issued in December 2020. PSE is working with the WUTC and other stakeholders to develop guidelines for implementation, PSE conducted a RFI (Request for Information) to determine the availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in 2021. RNG supply not utilized in PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

This IRP does not analyze hypothetical RNG projects that would connect to NWP or to PSE's system and displace conventional natural gas that would otherwise flow on NWP pipeline capacity. However, because of RNG's significantly higher cost, the very limited availability of sources, and the unique nature of each individual project, RNG is not suitable for generic analysis. The benefits of RNG are measured in terms of CO_2e reduction, which are unique to each project. The incremental costs of new pipeline infrastructure to connect the RNG projects to the NWP or PSE system are also unique to each project. Avoided pipeline charges realized by connecting acquired RNG directly to the PSE system will be considered, but are not significant relative to the cost of the RNG commodity. Contract RNG purchases present known costs, however, many projects may not materialize absent a capital investment by PSE. Due to the very competitive RNG development market, including competition from the California compliance markets, PSE is not prepared to discuss specific potential RNG projects in a public environment. Individual projects will be analyzed and documented as PSE pursues additional supplies.

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's natural gas system, annually. PSE is planning significant further investments in cost-effective RNG, and PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future voluntary RNG program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio. In order to meet the expectations in the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential. This represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. To be consistent with electric measures, the achievability factors for all natural gas retrofit measures was assumed to be 85 percent. Similar to electric measures, all natural gas measures receive a 10 percent conservation credit stemming from the Power Act of 1980. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called "bundles." For example, all measures that have a levelized cost of between $2.2 per Dth and $3.0 per Dth may be grouped into a bundle and labeled "Bundle 2." The lower cost bundles were further divided into smaller segments to ensure that some measures included in a larger, marginal bundle don't get missed.[10] The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 9-17 shows the price bundles and corresponding savings volumes in achievable technical potential that were developed for this IRP. The bundles are shown in dollars per therm and the savings for each bundles shown in 2031 and 2041 are in thousand dekatherms per year

10 / The $4.5 to $5.5 per Dth and the $5.5 to $7.0 per Dth bundles were divided into four bundles: $4.5 to $5.0, $5.0 to $5.5, $5.5 to $6.2 and $6.2 to $7.0. The narrower ranges allow for a more refined selection of conservation on the supply curve.

(MDth/year). These savings were developed using PSE's weighted average cost of capital (WACC) as the discount rate.

PSE currently seeks to acquire as much cost-effective natural gas demand-side resources as quickly as possible. The acquisition rate or "ramp rate" of natural gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures assume a 10-year ramp rate; in other words, they are acquired during the first 10 years of the study period.

Figure 9-17: Natural Gas DSR Cost Bundles and Savings Volumes (MDth/year)

	DSR Savings Volume (MDth/year)	
	2031	2041
Codes & Standards	725	1,446
Bundle 1: <$0.22	2,393	4,356
Bundle 2: $0.22 to$0.30	2,673	4,672
Bundle 3: $0.30 to $0.45	3,902	7,764
Bundle 4: $0.45 to $0.50	3,932	7,802
Bundle 5: $0.50 to $0.55	3,988	7,898
Bundle 6: $0.55 to $0.62	4,008	7,936
Bundle 7: $0.62 to $0.70	5,112	9,105
Bundle 8: $0.70 to $0.85	5,419	10,093
Bundle 9: $0.85 to $0.95	5,586	10,286
Bundle 10: $0.95 to $1.20	5,812	11,373
Bundle 11: $1.20 to $1.50	7,621	13,341
Bundle 12: >$1.50	10,421	17,051

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment*, for more detail on the measures, assumptions and methodology used to develop DSR potentials.*

In the final step, the natural gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM 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 9-18 illustrates the methodology described above.

Figure 9-18: General Methodology for Assessing Demand-side Resource Potential

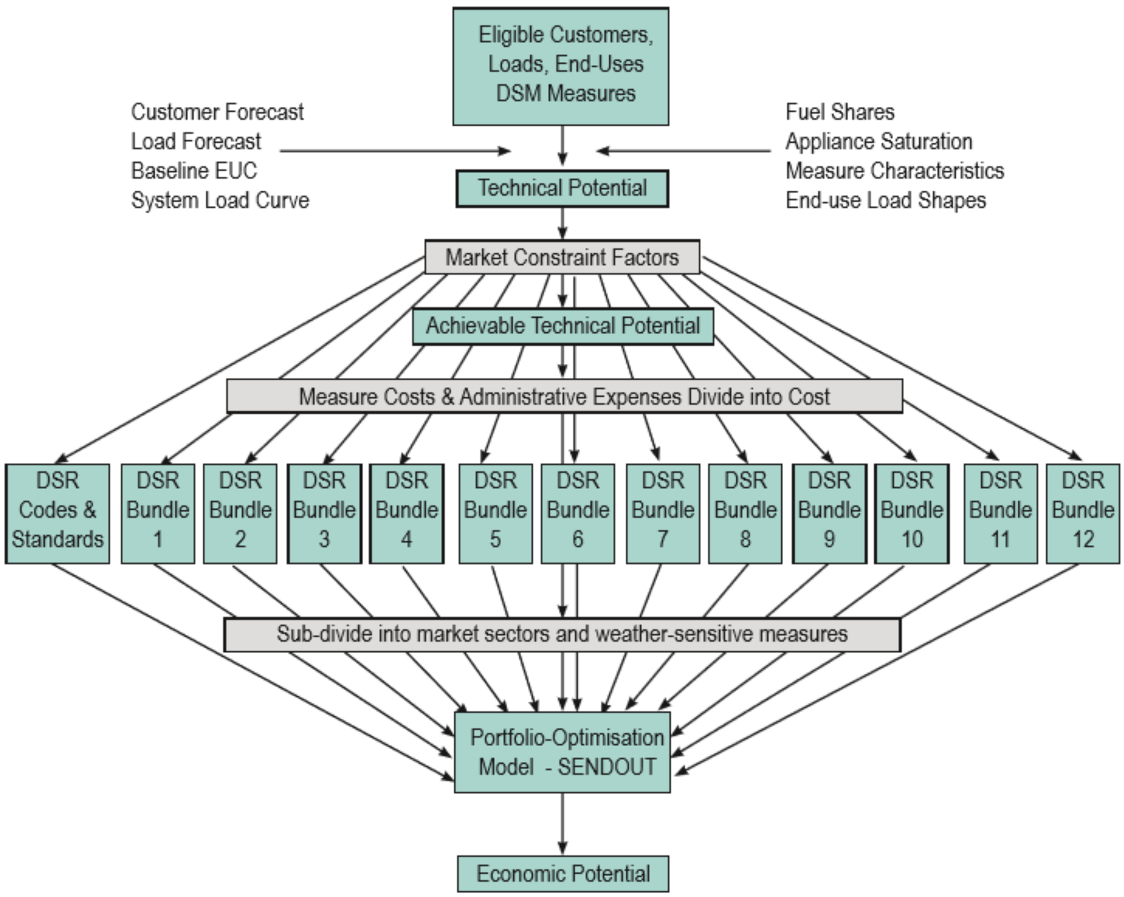


Figure 9-19 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side natural gas resource for a particular scenario.

Figure 9-19: Demand-side Resources – Achievable Technical Potential Bundles

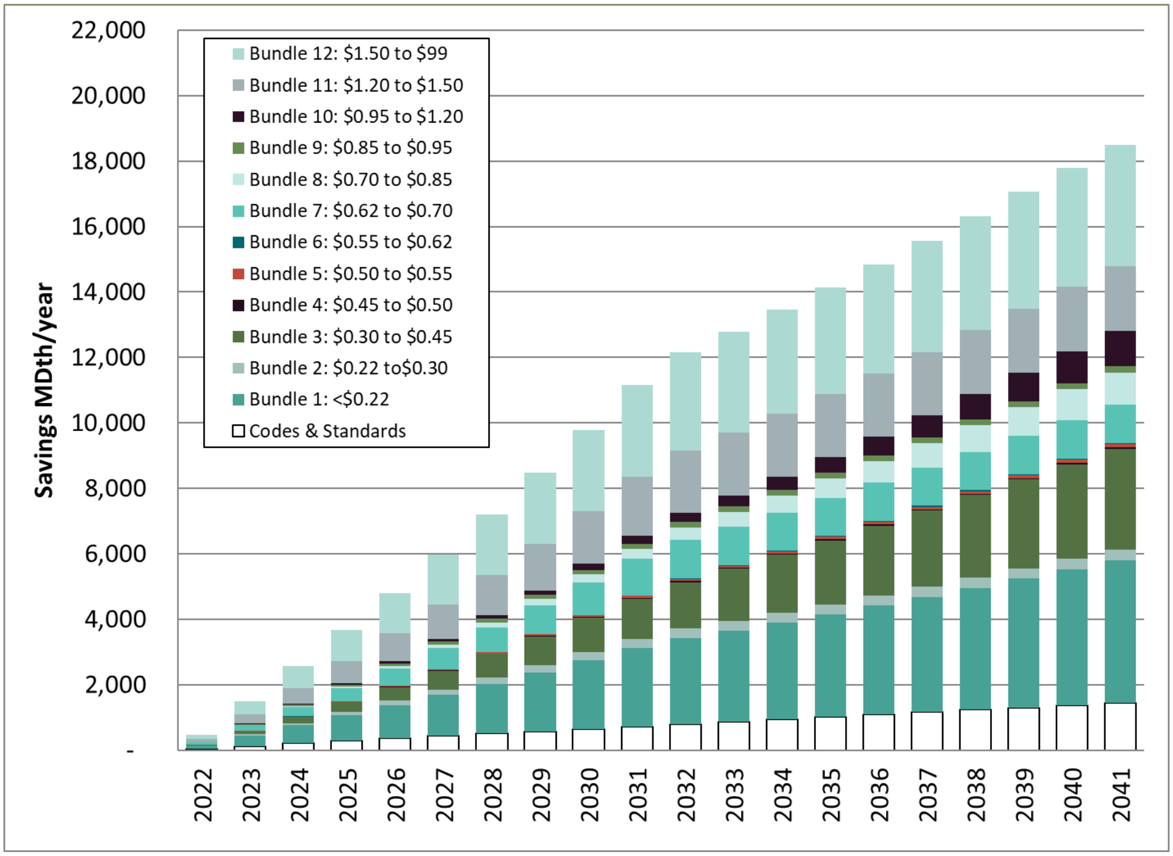
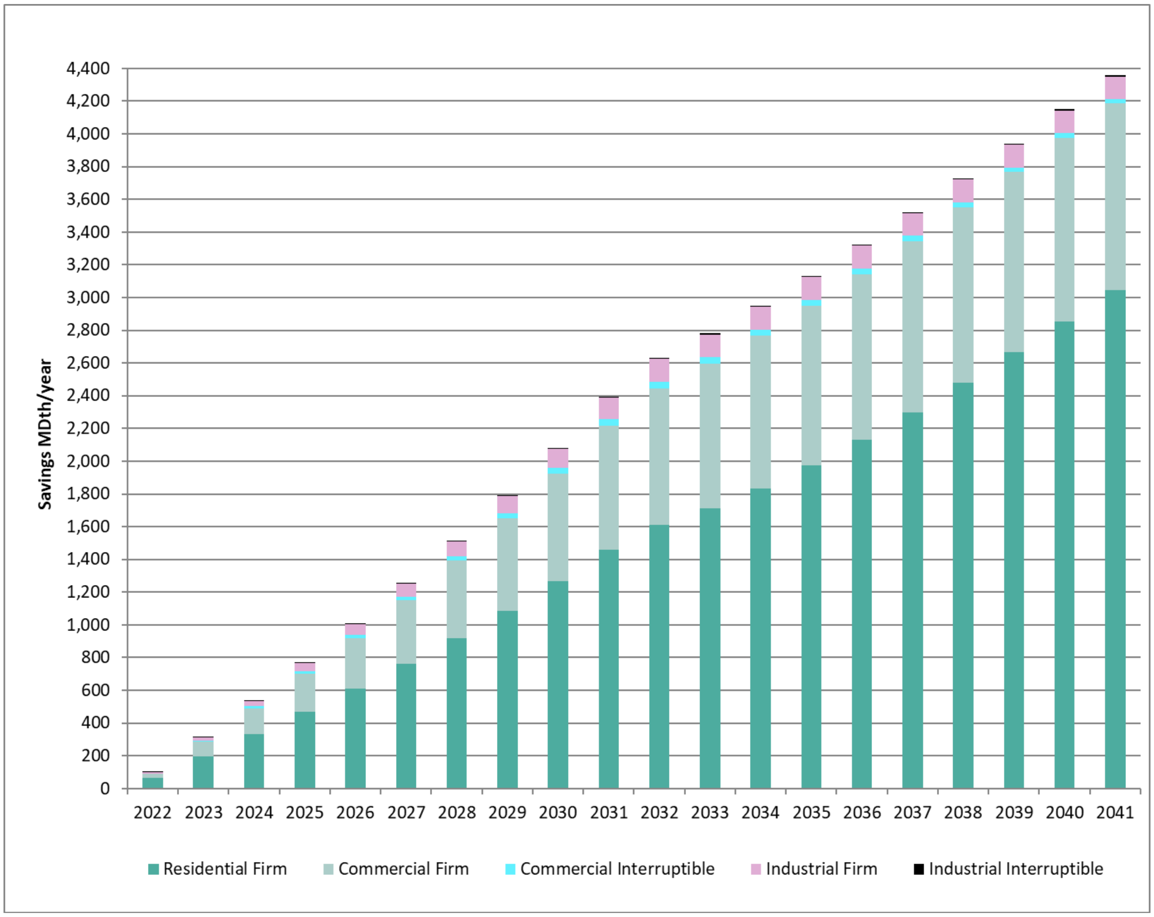


Figure 9-20 shows DSR savings subdivided by customer class. This input format is used in the GPM for all bundles in all the IRP scenarios.

Figure 9-20: Savings Formatted for Portfolio Model Input by Customer Class



5. NATURAL GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical 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 Mid Scenario, the natural gas sales portfolio is short resources beginning in the winter of 2031/32 and each year after that.** The High Scenario also has a deficit starting in 2026/27 and a growing resource shortfall throughout the study, while in the Low Scenario the portfolio is short beginning 2040/41.
2. **Resource needs are primarily met with demand-side resources in the Mid and Low Scenarios.** The gas portfolio model adds the same amount of demand-side resources in both scenarios. In both cases, it added slightly more DSR than is needed to meet the resource need due to the high total natural gas costs resulting from the SCGHG and upstream emissions adders.
3. **The High Scenario has a higher need and is short 165 MDth/day on the peak day in 2041.** The natural gas portfolio model adds the same amount of DSR as in the Mid and Low Scenarios and chooses Plymouth LNG, Swarr and pipeline capacity expansion on Northwest and Westcoast pipelines sourcing natural gas from Station 2 to meet resource need.
4. **Cost-effective DSR is higher in the 2021 IRP.** The cost-effective bundles in all sectors are higher on the supply curve compared to the 2017 IRP. The increase is due to a significant increase in the quantity of new DSR savings in the supply curve and substantially higher natural gas costs. The result is an overall increase in the cost-effective DSR
5. **Cost-effective DSR is the same in all three scenarios.** The total amount of cost-effective DSR chosen in the Mid, Low and High Scenarios did not change. The primary driving factor appears to be the high total natural gas cost, which the DSR helps to offset, thereby reducing portfolio cost.
6. **The Swarr LP-Air upgrade project is cost effective in the High Scenario** and is expected to provide 30 MDth per day of peaking capacity effective November 2037.
7. **The Tacoma area distribution system upgrade project was not needed.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.

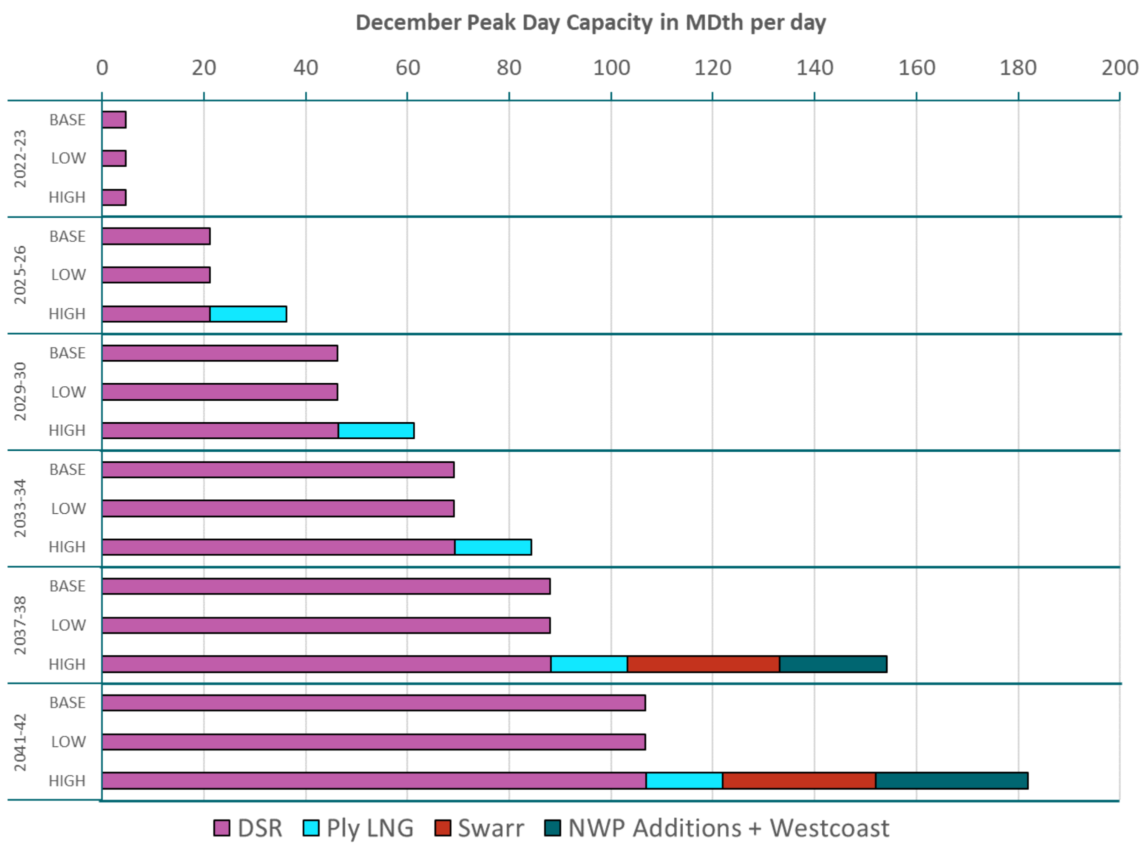
8. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in only the High scenario.** The GPM indicates this pipeline capacity is cost effective starting in 2034/35.
9. **Neither the Cross Cascades TC new pipeline or the Fortis BC KORP project are selected in any scenario.** The resource need is low enough to be satisfied by DSR and thus did not warrant a need for these resources. Additionally, these options present other constraints, such as requiring significant demand by third parties or reliance on other projects and timing outside the control of PSE to become viable.
10. **The Mist Storage project was not selected in any of the Scenarios.** The resource need is low in the 2021 IRP and is mostly filled with cost-effective DSR.
11. **The carbon cost assumption was significantly higher in the 2021 IRP compared to the 2017 IRP, and this impacted resource choices.** The levelized cost of carbon adders, which included social cost of greenhouse gases (SCGHG) and upstream emissions, was more than double the levelized natural gas commodity price in all three scenarios. This high cost resulted in greater volumes of demand-side resources being selected in all three scenarios. The high total natural gas cost drove the selection of cost-effective DSR in all three scenarios.
12. **The level of cost-effective DSR found in the deterministic Mid-Low-High Scenarios is a robust result**. In the stochastic analysis, this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly.
13. **Cost-effective DSR reduced both cost and risk in the natural gas portfolio** according to the stochastic analysis.

Natural Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, natural gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by natural 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 the new supply curve and load growth assumptions. Also, the timing of pipeline additions was limited to five-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the three scenarios are illustrated in Figure 9-21 for several winter periods. Combination #1 (NWP plus Westcoast), Combination #5 (Plymouth LNG peaker) and Combination #7 (Swarr LP Plant) are chosen only in High Scenario. The Low and Mid Scenarios both chose only DSR.

Figure 9-21: Natural Gas Resource Additions in 2022/23, 2025/26, 2029/30, 2033/34 and 2041/42 (Peak Capacity – MDth/day)



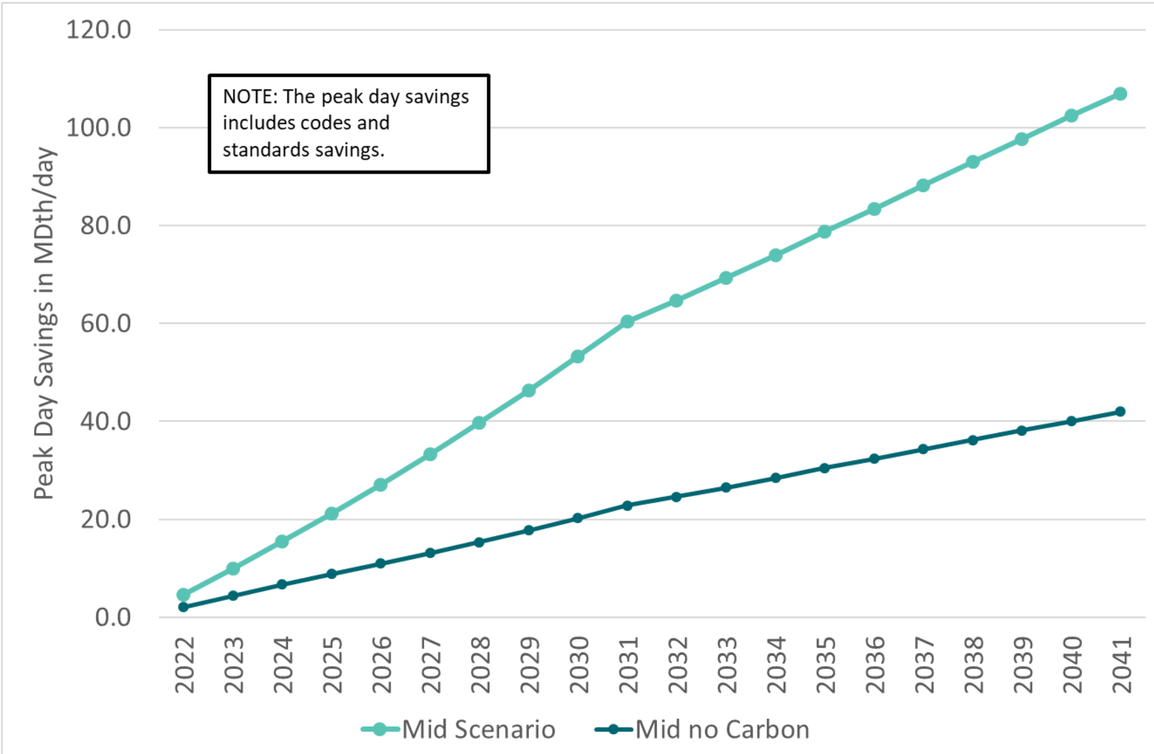
Demand-side Resource Additions

Two categories of demand-side resources are input into the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to natural gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

Carbon costs do impact the amount of cost-effective DSR. Compared to the 2017 IRP, the 2021 IRP carbon costs in the Mid Scenario are significantly higher relative to natural gas prices, which is a function of both declining natural gas prices and higher carbon cost assumptions resulting from carbon legislation passed in the state of Washington in 2019. The carbon legislation requires the inclusion of SCGHG and upstream related carbon emissions. Including these two adders in the price of natural gas results in a total natural gas cost that is over three times the cost of the natural gas itself. This total natural gas cost is what is used to make capacity expansion decisions in the GPM, and in these conditions, DSR is preferred in all scenarios since it is a resource that directly offsets the high total natural gas cost and helps to minimize the portfolio cost.

The sensitivity of DSR to carbon prices is illustrated in Figure 9-22. In the Mid Scenario, when including the carbon adders, cost-effective DSR is 107 MDth per day by 2041/42. This amount is actually more than the resource need in 2041/42 of 88 MDth per day, meaning DSR is being over built by about 19 MDth per day. When the Mid Scenario is run with no carbon adders, using only the natural gas cost, the cost-effective DSR drops to 42 MDth per day. In terms of natural gas supply planning, 42 MDth per day is not a significant volume; however, it does highlight that including a CO_2 price in the IRP Mid Scenario increases conservation. The carbon adders more than double the cost-effective DSR over the 20-year period.

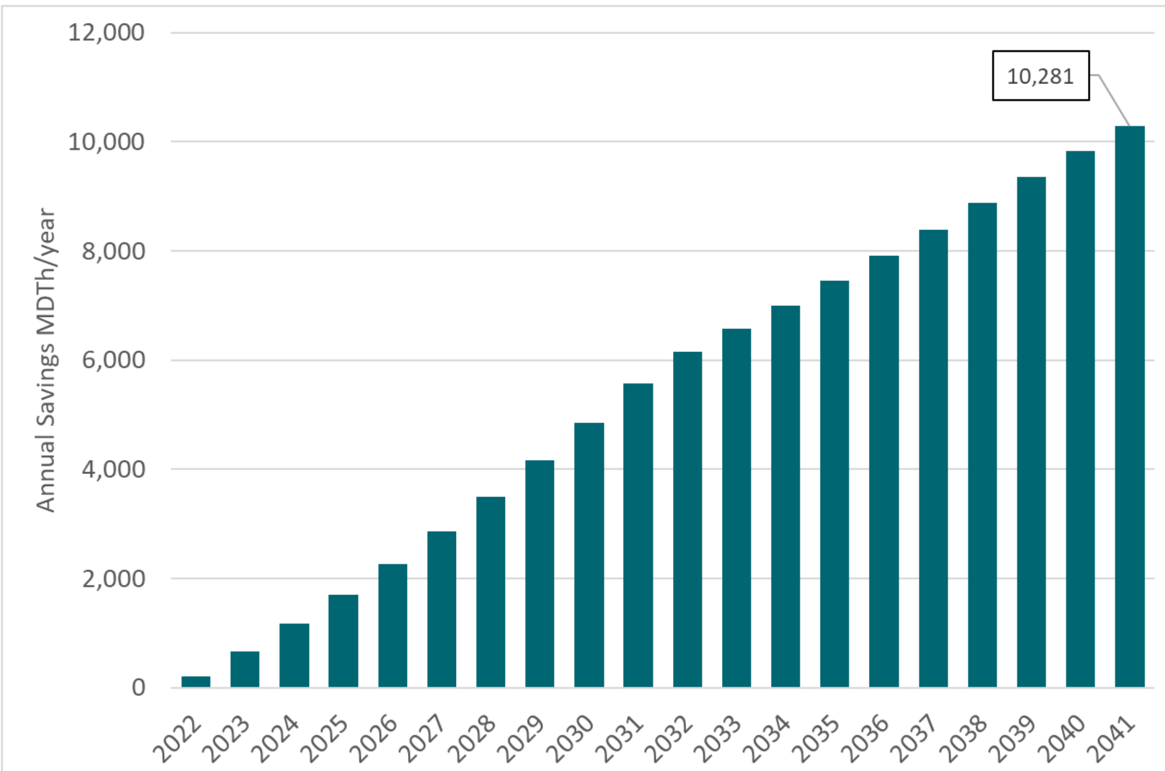
Figure 9-22: Sensitivity of Carbon to Cost-effective Natural Gas Energy Efficiency Savings in the Mid Scenario



DSR is not very sensitive to high avoided costs in the natural gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan did not vary by scenario.

Energy savings for all three scenarios are shown in Figure 9-23.

Figure 9-23: Cost-Effective Natural Gas Efficiency, Annual Energy Savings for Mid/Low/High Scenario



The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 9-24 and 9-25, below.

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more detail on this analysis.*

Figure 9-24: Natural Gas Sales Cost-effective DSR Bundles by Class and Scenario

Cost-effective Bundles	Mid	Low	High
Residential Firm	9	9	9
Commercial Firm	9	9	9
Commercial Interruptible	6	6	6
Industrial Firm	9	9	9
Industrial Interruptible	9	9	9

Figure 9-25: Natural Gas Sales Cost-effective Annual Savings by Class and Scenario (MDth/year)

Savings (MDth/year)	Mid	Low	High
Residential Firm	7,984	7,984	7,984
Commercial Firm	2,093	2,093	2,093
Commercial Interruptible	39	39	39
Industrial Firm	156	156	156
Industrial Interruptible	8	8	8
Total (MDth per year)	**10,281**	**10,281**	**10,281**

Overall, the economic potential of DSR in the 2021 IRP is higher than in the 2017 natural gas sales Mid Scenario, and higher-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 9-26).

The upward shift in overall savings is due to two factors:

- Higher total natural gas costs that include carbon adders for both end-use and upstream emissions.
- Updates to the measure costs and savings assumptions such that the achievable technical potential was higher and some measures shifted to lower cost effective bundles in the 2021 IRP.

It is notable that the two factors above were a much stronger influence than the following factors, which would have reduced the available DSR under normal circumstances:

- A lower demand forecast in the 2021 IRP than the 2017 IRP
- Four additional years of program implementation will elapse between the 2017 IRP and 2022 when the 2021 IRP study starts, which means that four years of conservation implementation will have reduced the available DSR from the supply curve

> > > See Appendix E, Conservation Potential Assessment and Demand Response Assessment, *for more information on the development of DSR bundles.*

Figure 9-26: Cost-effective Natural Gas Energy Efficiency Savings, 2017 IRP vs 2021 IRP

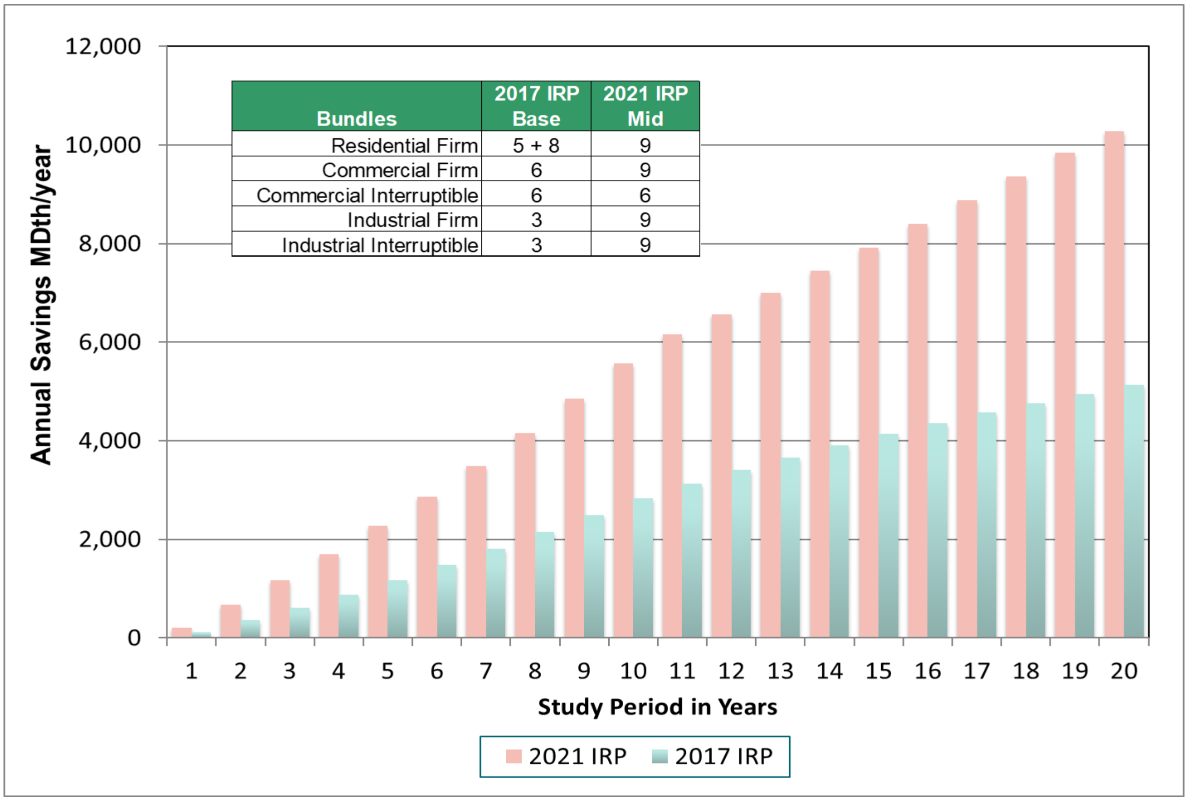


Figure 9-27 compares PSE's energy efficiency accomplishments, current targets and the new range of natural gas efficiency potentials determined by the 2021 IRP. In the short term, the 2021 IRP indicates an economic potential savings of 1,192 MDth for the 2022-2023 period for all three scenarios.[11] These two-year program accomplishments and projections show an upward trend, with the 2021 IRP results indicating that the trend is accelerating due to higher avoided costs and more cost-effective saving measures in the supply curve.

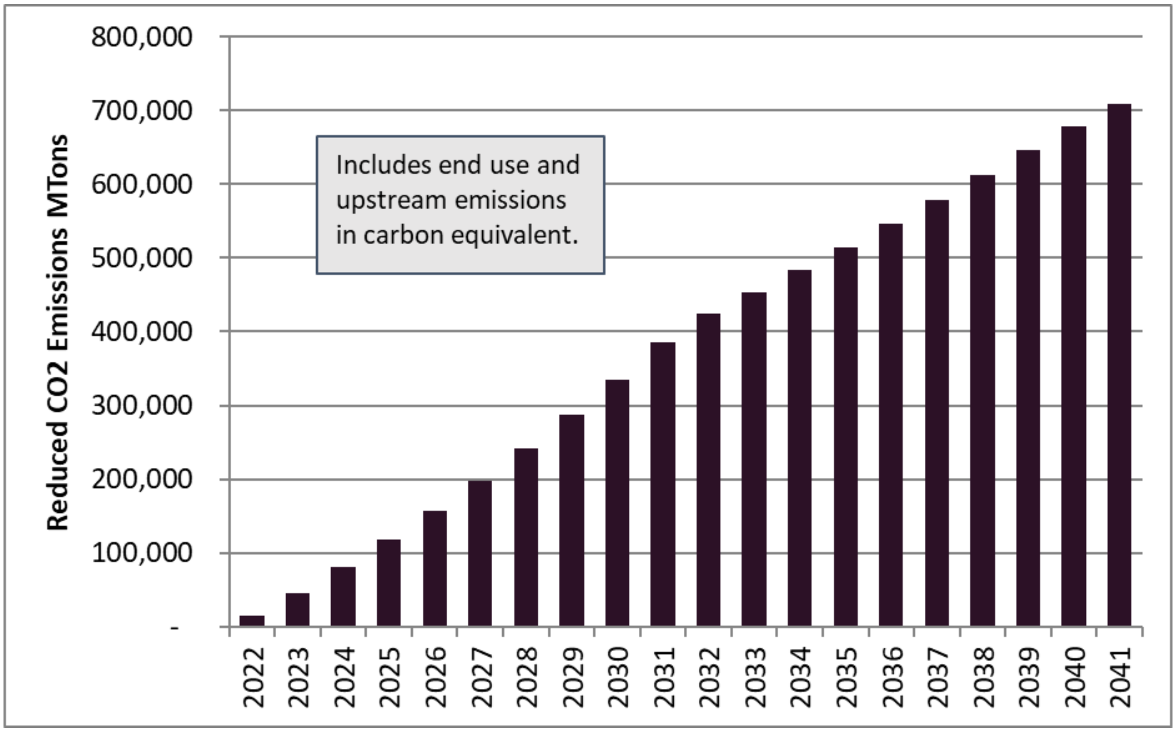
Figure 9-27: Short-term Comparison of Natural Gas Energy Efficiency in MDth

Short-term Comparison of Natural Gas Energy Efficiency	2-year Program Savings (Mdth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP Scenarios	1,192

11 / *These savings are based on a no-intra year ramping, which is used to set conservation program targets.*

Figure 9-28 shows the impact on CO_2 emissions from energy efficiency measures selected in the Mid, Low and High Scenarios.

Figure 9-28: CO_2 Emissions Reduction from Energy Efficiency in Mid, Low and High Scenarios



Peaking Resource Additions

The Swarr LP-Air upgrade project and the Plymouth LNG peaker contract were selected as least cost in only the High Scenario due to the higher resource need created by the higher demand forecast in this scenario.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2025/26 winter season, a bit later than the other non-pipeline alternatives were made available. The pipelines were not available earlier due to the lead time needed to develop these resources, but this was not a constraint to the portfolio model. The pipelines were chosen only in the High Scenario, which had a higher resource need due to higher demand. In the High Scenario, the GPM selected 30MDth a day of NWP with Westcoast from Station 2 in the out year.

The other pipeline additions offered in Combinations #2 (KORP) and #3 (Cross Cascades) were not economical in any of the scenarios.

Observation

All of the selected resources (listed here in general order of least cost) – DSR, Plymouth LNG Peaker, Swarr LP-Air, and Northwest + Westcoast pipeline expansion – are within PSE's control (with the exception of the pipeline expansion). The timing of individual projects can be fine-tuned by PSE in response to load growth changes, and none of these projects rely on participation by another contracting party in order to be feasibly implemented.

Complete Picture: Natural Gas Sales Mid Scenario

A complete picture of the Mid Scenario optimal resource portfolio for natural gas sales is presented in graphical and table format in Figures 9-29 and 9-30, respectively.

*> > > **See Appendix I, Natural Gas Analysis Results,** for additional scenario results.*

Figure 9-29: Natural Gas Sales Mid Scenario Resource Portfolio

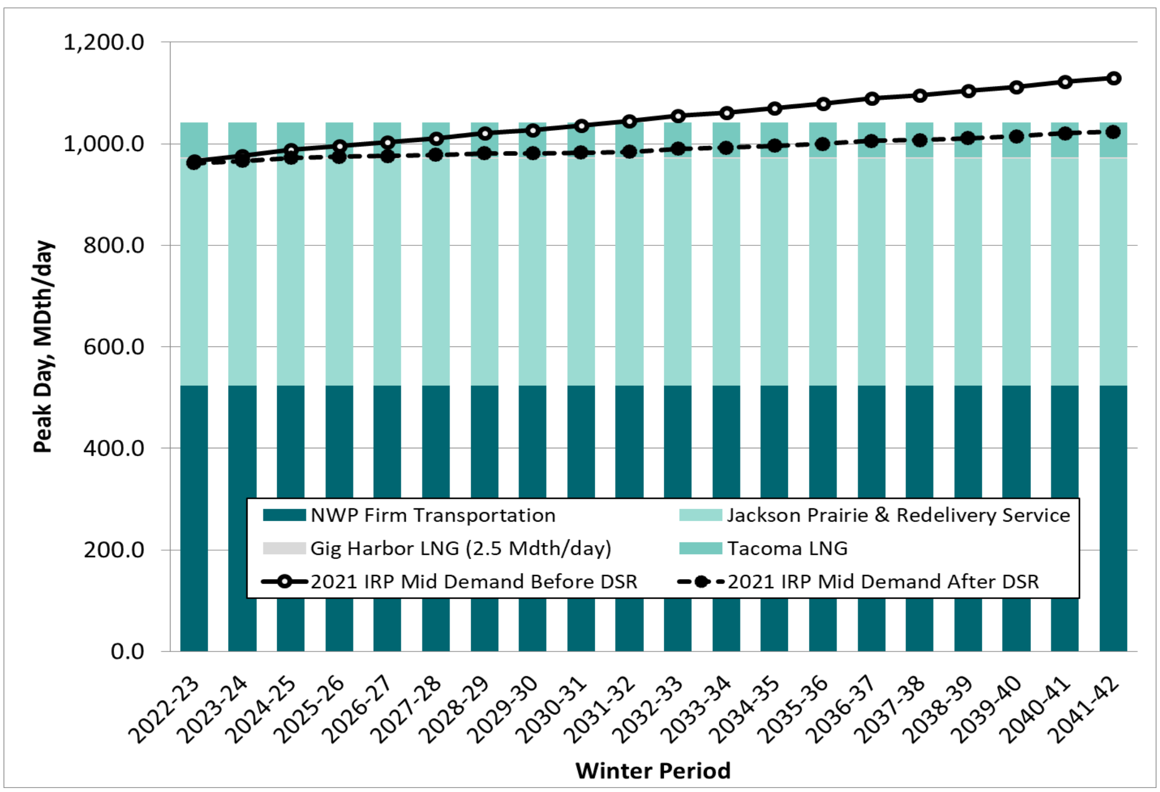


Figure 9-30: Natural Gas Sales Mid Scenario Resource Portfolio (Table)

		Winter Period		
Resource Alternative	**Option**	**2025/26**	**2030/31**	**2041/42**
NWP Additions + Westcoast	#1	-	-	-
KORP	#2	-	-	-
NWP from AECO	#3	-	-	-
Mist Storage	#4	-	-	-
Ply LNG	#5	-	-	-
LNG Tacoma Distr	#6	-	-	-
Swarr	#7	-	-	-
DSR	DSR	21	53	107
Total in MDth/day		**21**	**53**	**107**

Average Annual Portfolio Cost Comparisons

Figure 9-31 should be read with the awareness that 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 forecast rate-base costs related to Jackson Prairie storage, the Tacoma LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 9-31: Average Portfolio Cost of Natural Gas for Gas Sales Scenarios

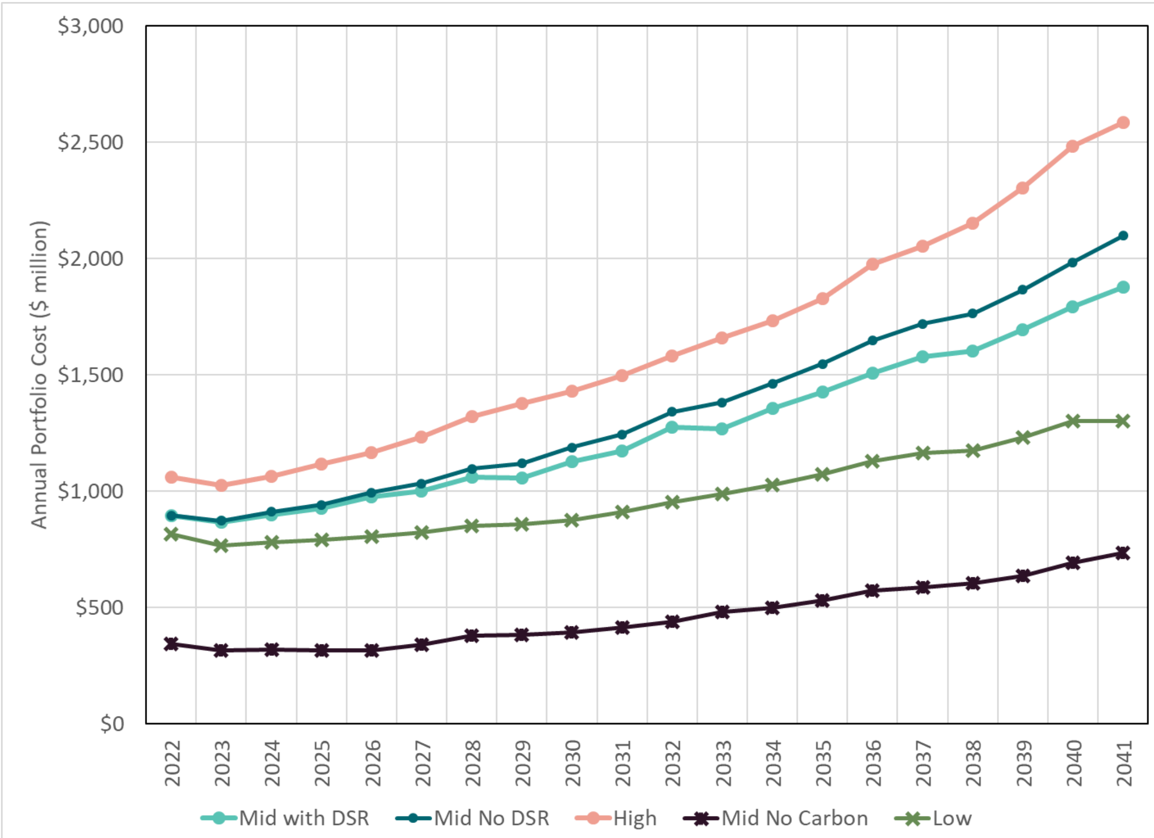


Figure 9-31 shows that average optimized portfolio costs are heavily impacted by natural gas prices and CO_2 cost assumptions included in each scenario.

- The assumed total cost of natural gas supply has the greatest influence on portfolio costs. Natural gas costs were high and relatively close in all three scenarios, and the resulting average portfolio costs were also high and fairly close to each other in comparison to the Mid No Carbon case shown above.
- DSR produces significant savings, as shown by the Mid Scenario with DSR versus the Mid No DSR lines. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Sensitivity Analyses

Five sensitivities were modeled in the natural gas sales analysis for this IRP. Sensitivities start with the Mid Scenario portfolio and change one resource, regulation or condition. This allows PSE to evaluate the impact of a single change on the portfolio.

A. AR5 Upstream Emissions

This sensitivity uses the AR5 methodology for calculating the upstream natural gas emissions rate instead of the AR4 methodology.

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology.

This sensitivity results in higher emission rates for both the Canadian and U.S. sourced natural gas. Figure 9-32 shows the emission rates for AR4 and AR5.

Figure 9-32: Upstream Emissions for AR4 and AR5

Sensitivity A	(Canadian Supply) gCO2e/MMBtu	(Domestic Supply) gCO2e/MMBtu
AR4	10,803	12,121
AR5	11,564	13,180

AR5 slightly increased total natural gas costs (see Figure 9-33), but made no change to the resource mix in the Mid Scenario. The GPM selected the same level of DSR as in the Mid Scenario, but portfolio costs were higher due to the increased upstream emissions adder (see Figure 9-34).

Figure 9-33: Upstream Emission Costs in $/MMBtu AR4 vs. AR5

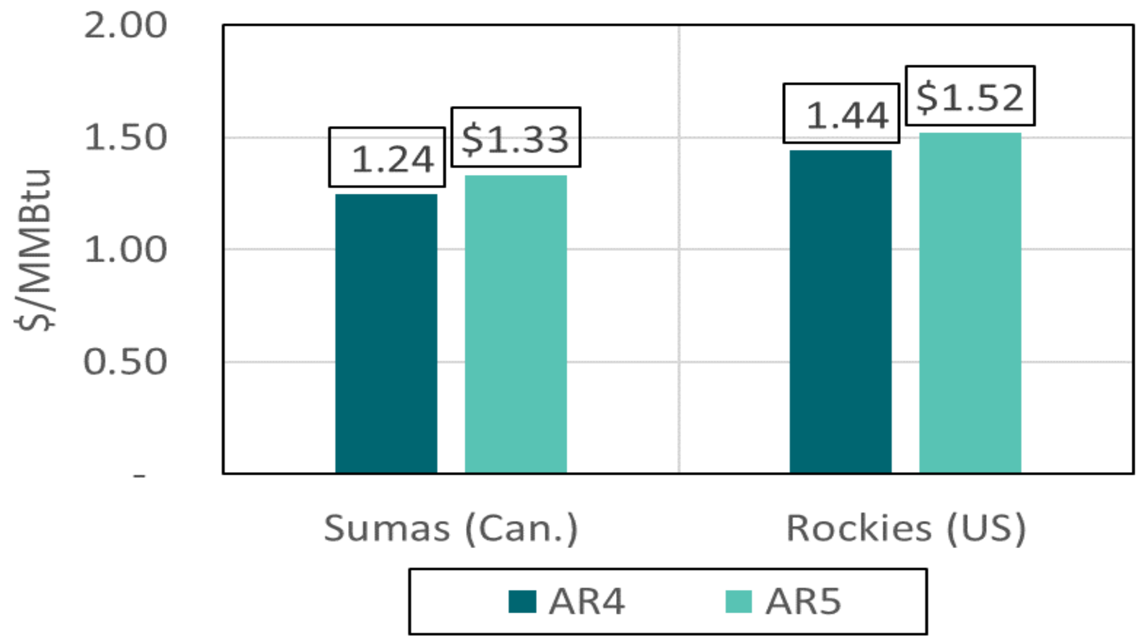


Figure 9-34: 20-year NPV for AR5 Portfolio vs. AR4 Portfolio

Sensitivity A	Portfolio NPV, $ billion
Mid Scenario with AR4	$12.660
Mid Scenario with AR5	$12.758

B. 6-year Conservation Ramp Rate

This sensitivity changes the ramp rate for conservation measures from 10 years to 6 years, allowing PSE to model the effect of faster adoption rates.

BASELINE ASSUMPTION: Conservation measures ramp up to full implementation over 10 years.
SENSITIVITY > Conservation measures ramp up to full implementation over 6 years.

The GPM selected the same bundles as in the Mid Scenario, however, the DSR was front-loaded due to the faster ramp rate on the discretionary DSR measures. The overall savings in the 20-year study period did not change (see Figure 9-35), but since the DSR was captured earlier, the NPV of the portfolio was lower (see Figure 9-36)

Figure 9-35: Savings from 6-year Ramp Rate vs. 10-year Ramp Rate

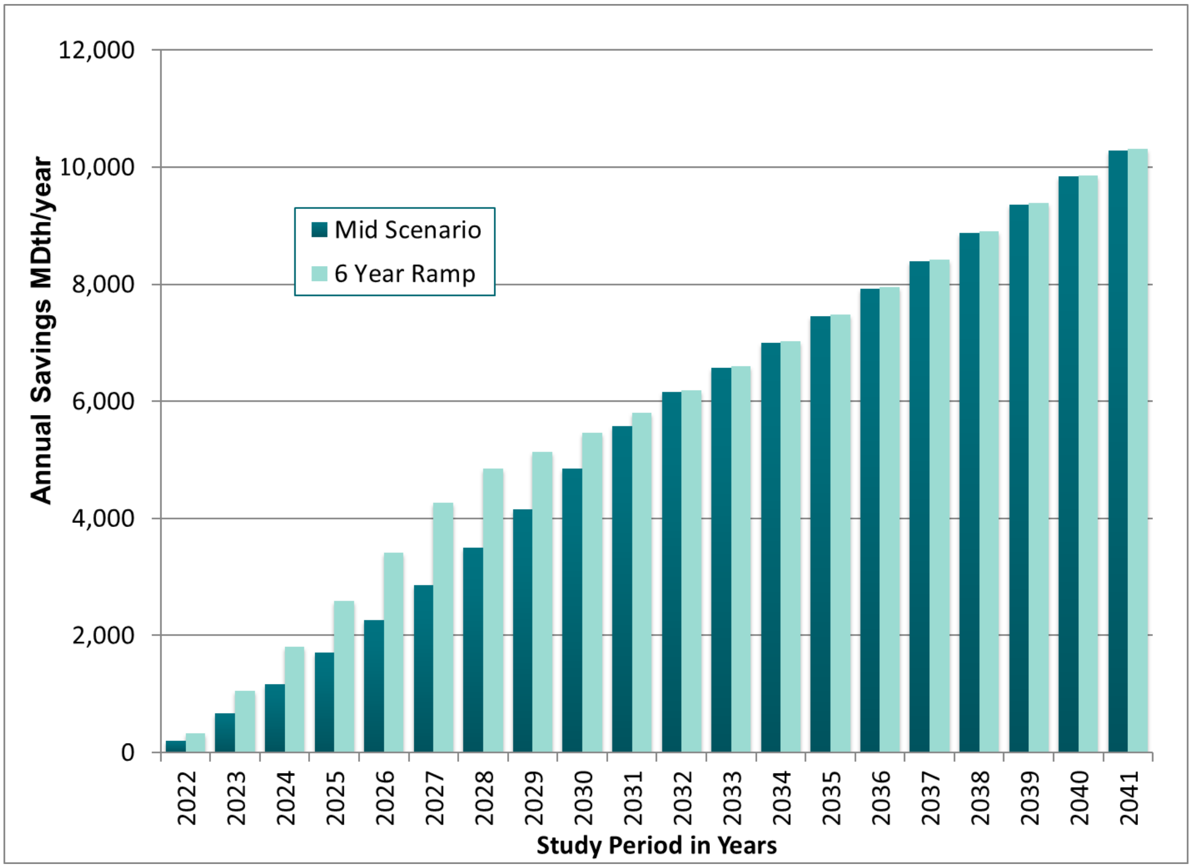


Figure 9-36: NPV for 6-year Ramp Rate vs. 10-year Ramp Rate

Sensitivity B	Portfolio NPV, $ billion
Mid Scenario with 10-year Ramp Rate	$12.660
Mid Scenario with 6-year Ramp Rate	$12.623

C. Social Discount Rate for DSR

This sensitivity changes the discount rate for DSR projects from the current discount rate of 6.8 percent to 2.5 percent. By decreasing the discount rate, the present value of future DSR savings is increased, making DSR more favorable in the modeling process. DSR is then included as a resource option with the new financing outlook.

BASELINE ASSUMPTION: The discount rate for DSR measures is 6.8 percent.
SENSITIVITY > The discount rate for DSR measures is 2.5 percent.

A social discount rate that was lower than PSE's assigned WACC was applied to the demand-side resource alternative in this sensitivity analysis to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as the 2.5 percent nominal discount rate referenced in CETA SCGHG legislation. The 2.5 percent discount rate shifted measures to lower cost points on the conservation supply curve. Since the social discount rate caused the measures to shift to lower cost bundles, the net effect was that cost-effective savings were slightly higher using the social discount rate.

See Figures 9-37 and 9-38 for the DSR savings comparison.

Figure 9-37: Savings by Bundle, 6.8% Discount Rate in IRP Mid Scenario vs. 2.5% Social Discount Rate in Sensitivity C

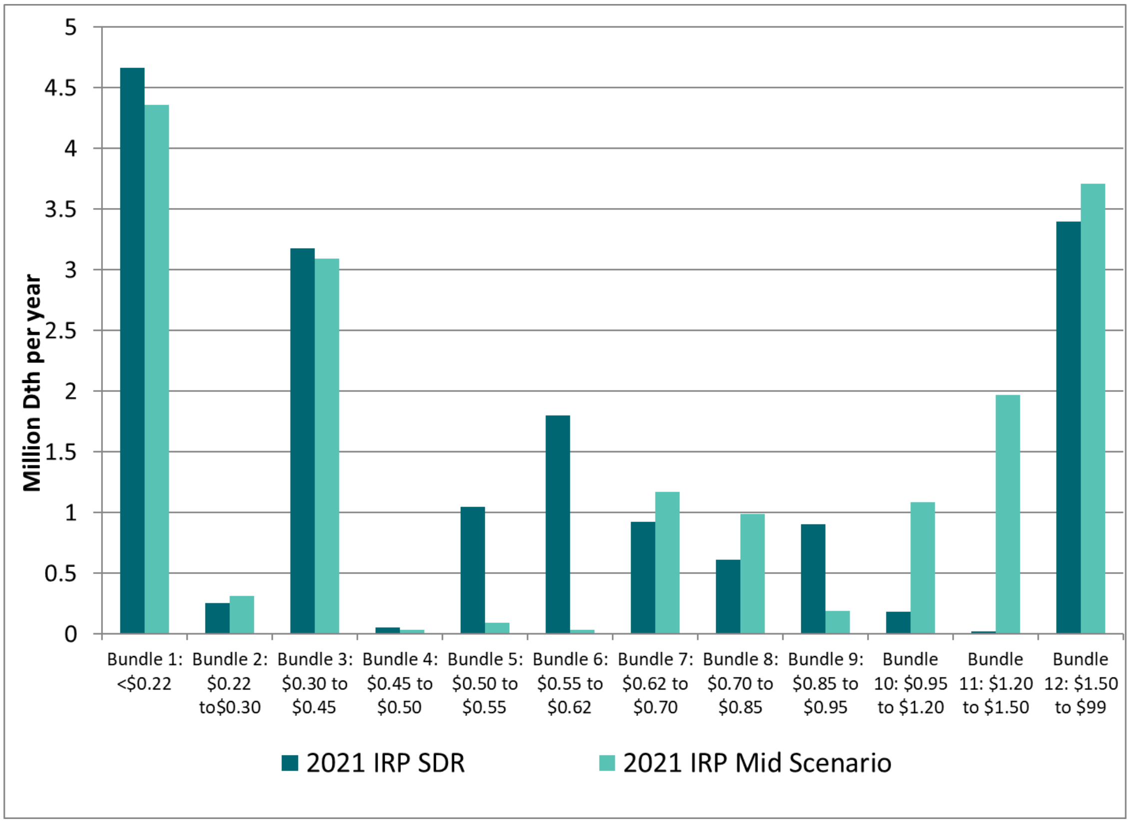


Figure 9-38 Cost-effective Level of Natural Gas DSR, 6.8% Mid Scenario Discount Rate vs. 2.5% Social Discount Rate

Sensitivity C Savings	6.8% Mid Scenario (Mdth/year)	2.5% Social Discount Rate (Mdth/year)
Residential Firm	7,984	9,613
Commercial Firm	2,093	2,107
Commercial Interruptible	39	39
Industrial Firm	156	156
Industrial Interruptible	8	8
Total (MDth per year)	**10,281**	**11,923**

D. Fuel Switching, Gas to Electric

This sensitivity models accelerated adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity illustrate the effects of a rapid replacement of gas end uses with electricity as their fuel on the portfolio and the demand profile of the PSE service territory. For the purpose of this IRP and this gas to electric scenario, electric energy and peak demand potential estimates apply only to PSE's electric service territory and exclude the impacts on other electric utilities. There are many possible fuel switching pathways, and PSE presents this sensitivity as one possible view. Further analysis is required to understand all of the impacts and costs associated with fuel switching.

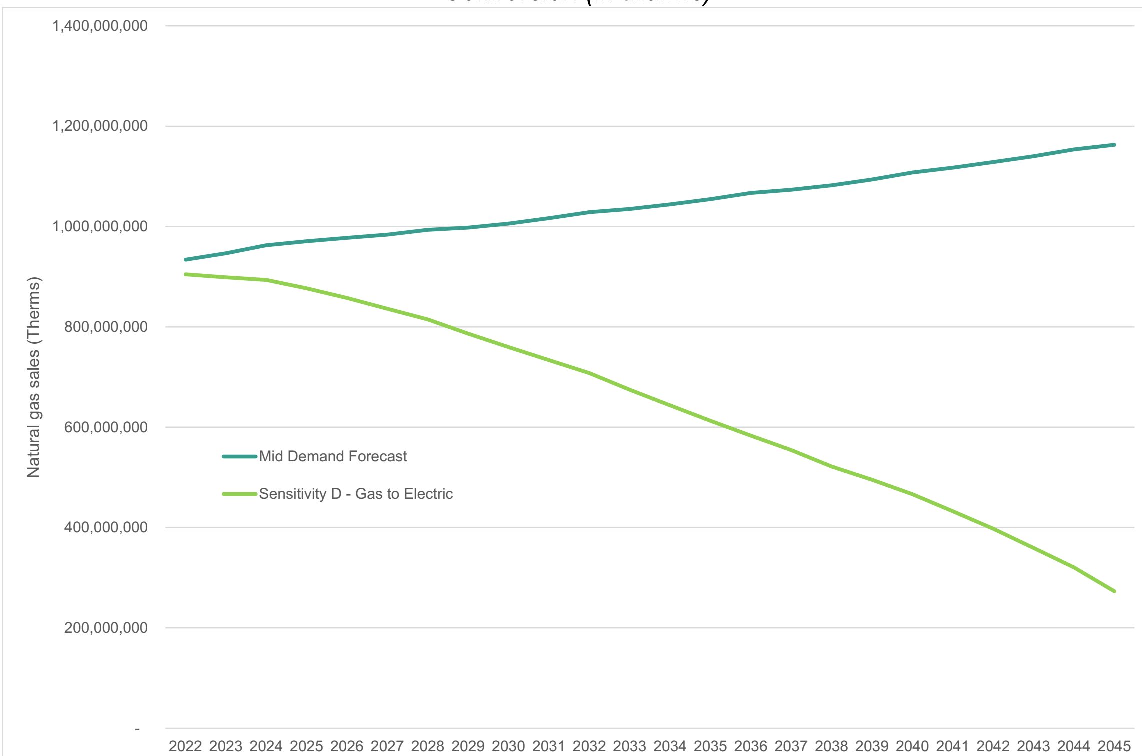
Figure 9-39: Gas to Electric Fuel Switching Assumptions

	Assumption
PSE Customer Base	Energy demand is reduced based on the hybrid heat pumps included in the mid demand forecast for the natural gas portfolio.
Hybrid Heat Pumps	Hybrid heat pumps rolled out for existing and new construction. By 2030, 50% of the total addressable achievable potential will be attained, and by 2050, 100% of the achievable technical potential will be completed. The end uses will include space heating loads with a natural gas backup heat pump.
Other End Uses (water heating, cooking, etc)	Converted to electric uses
Industry Electrification	30% of all the electric loads in the industrial sector are converted from natural gas to electric by 2050

BASELINE ASSUMPTION: The portfolio uses the demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an accelerated replacement of natural gas end uses with electricity in the PSE service territory resulting in a lower natural gas demand forecast.

This sensitivity looks not only at the impacts to the natural gas portfolio, but it also accounts for the cumulative annual electric energy impacts to PSE's system of converting natural gas equipment for each customer sector. The residential sector shows the biggest impact, accounting for 53 percent and 60 percent of the total cumulative energy impacts in 2030 and 2045, respectively. Compared to the total PSE electric load forecast in the Mid Scenario, these impacts represent additional electric energy loads of 7.9 percent in 2030 and 35.5 percent in 2045, and additional electric peak demands of 6 percent and 17 percent in 2030 and 2045, respectively. For the natural gas sales system, the residential sector accounts for 68 percent of the total natural gas reductions in 2030 and 73 percent of total natural gas reductions 2045. Compared to PSE's total 2019 natural gas sales, natural gas sales decrease by 21 percent by 2030 and 74 percent by 2045.

Figure 9-40: Annual Natural Gas Sales – Mid Demand Compared to Sensitivity D, Electric to Gas Conversion (in therms)

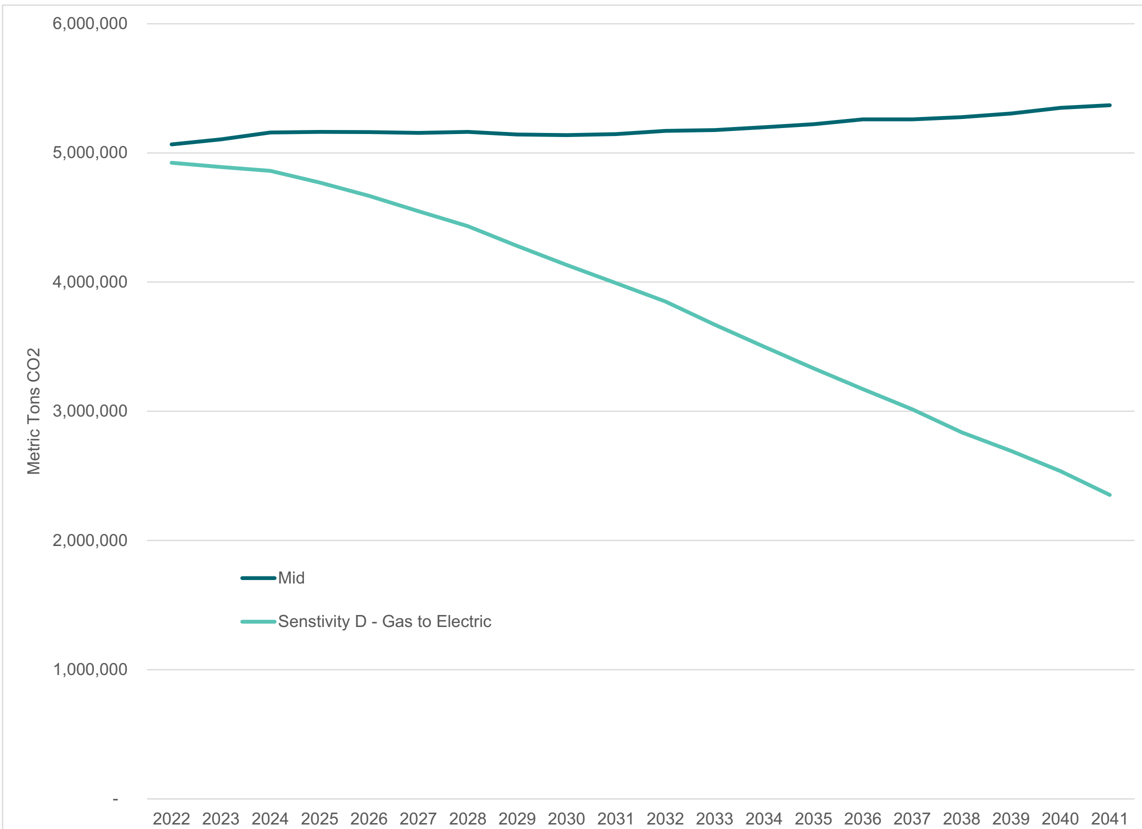


For the residential and commercial sectors, PSE calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. Then each natural gas unit was matched to an equivalent electric equipment; annual energy consumption, peak demand and cost assumptions were then applied to the electric equipment to calculate the total impact of conversion.

To mitigate the peak demand impacts of additional winter space heating loads to the electric system, this sensitivity modeled replacing existing residential construction natural gas furnaces with a hybrid air-source heat pump with natural gas backup that switches from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. A full discussion of equipment and impacts by sector is located in Appendix E.

The cost of the conversion was added to the natural gas portfolio. Because of this, portfolio costs increased from $12.66 billion in the Mid Scenario to $14.95 billion in Sensitivity D. The conversion also decreased loads and emissions in the natural gas portfolio. Emissions decreased by 20 percent in 2030 and 47 percent by 2040

Figure 9-41: Natural Gas Emissions – Mid Scenario and Sensitivity D (metric tons CO_2)



Since this sensitivity affects both the natural gas and electric portfolios, combined portfolio costs are also provided. Figures 9-42 and 9-43 compare the combined electric and natural gas portfolio costs for the Mid Scenario and Sensitivity D, and Figure 9-44 compares the direct (generation) and indirect (market) emissions of the combined portfolios. For this analysis, the electric portfolio did not include alternative compliance to achieve carbon neutrality by 2030. Also not included were additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs.

Figure 9-42: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billions $)			
	Portfolio	Electric	Natural Gas	Total	Change from Mid
1	Mid Scenario	$15.53	$12.66	$28.19	--
D	Fuel Switching, Gas to Electric	$19.56	$14.95	$34.51	$6.32

Figure 9-43: Natural Gas and Electric Annual Portfolio Costs

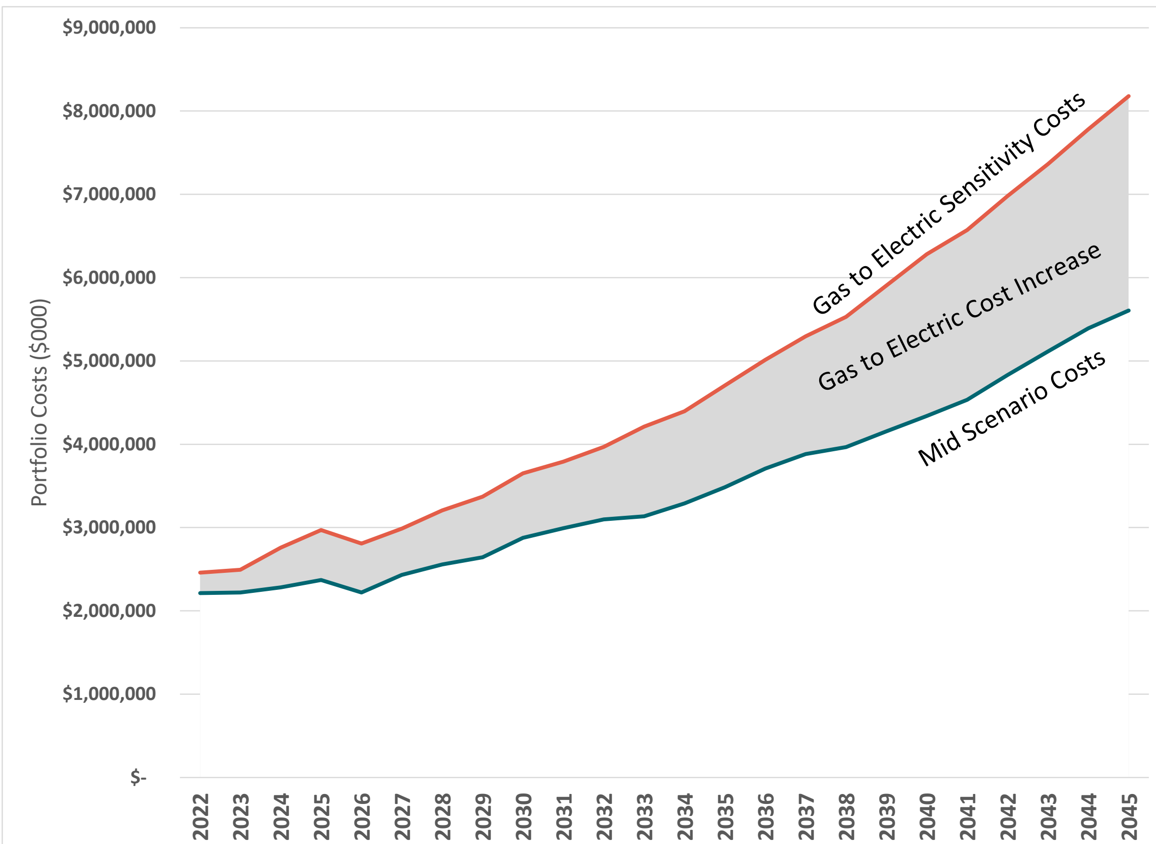
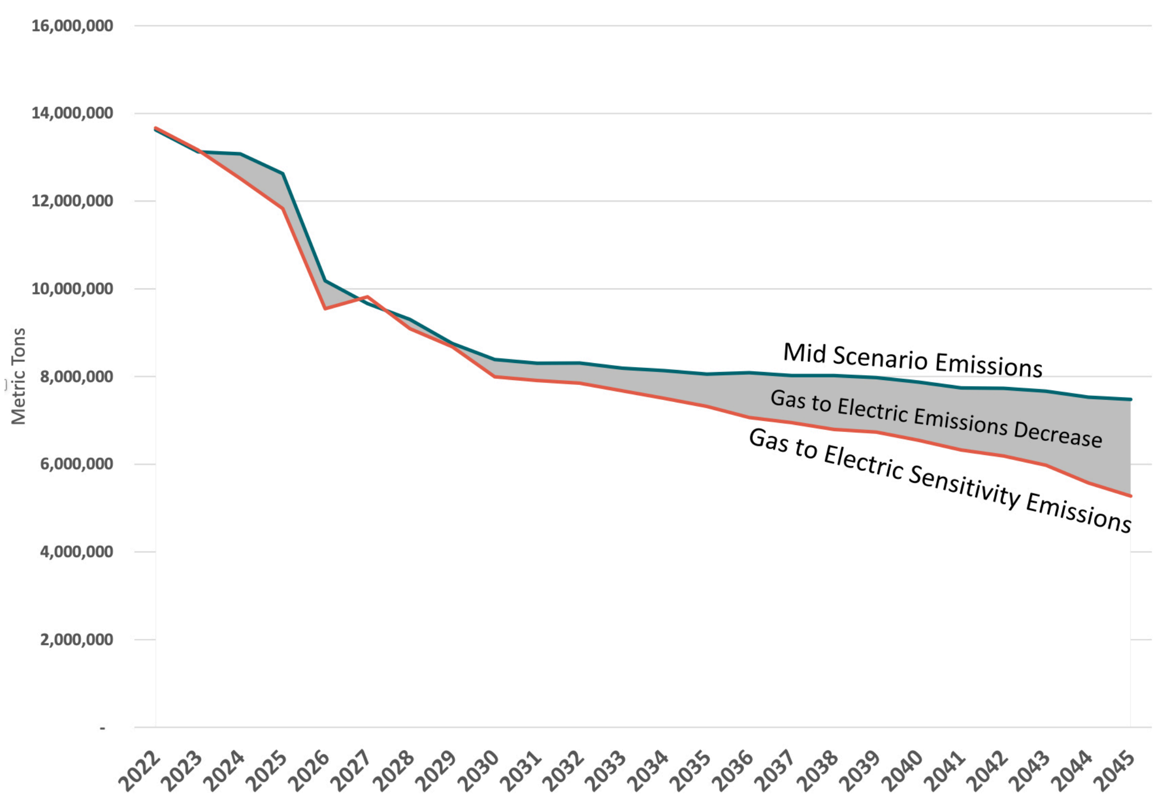


Figure 9-44: Direct and Indirect Portfolio Emissions – Mid Scenario and Sensitivity D, (not including alternative compliance for the electric portfolio)



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, PSE divides the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 9-45 shows the results of this calculation for Sensitivity D. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent.

Figure 9-45: Cost of Emissions Reduction – Mid Scenario and Sensitivity D

Portfolio	Combined GHG Emissions (millions tons CO_2eq, 24-year levelized)	Combined Portfolio Cost ($ billions, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	116	$28.19	-
D Gas to Electric	109	$34.51	1.11

E. Temperature Sensitivity

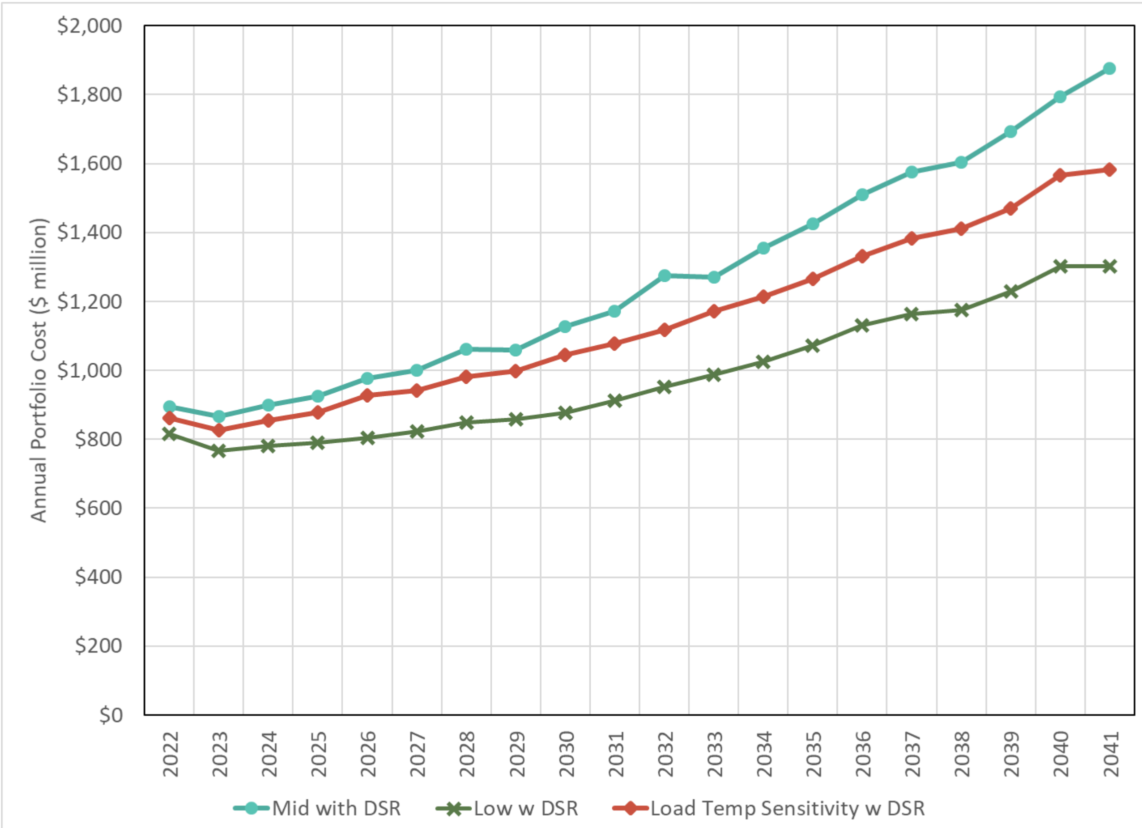
This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity will illustrate changes in PSE's load profile.

BASELINE ASSUMPTION: The Base Demand Forecast used in the Mid Scenario is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019.

SENSITIVITY > PSE uses temperature data from the Northwest Power and Conservation Council (the “Council”). The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council’s climate model.

The temperature sensitivity resulted in higher average temperatures, and a reduction in the load forecast of about 15 percent by 2045. This did not impact the peak design day, so the GPM selected the same resource mix in the capacity expansion; in other words, the same cost-effective DSR was selected as in the Mid Scenario portfolio. Total system costs were slightly lower than the Mid Scenario portfolio, as a lower load led to lower natural gas need, but they were not as low as system costs in the Low Scenario portfolio. This is shown in Figure 9-46 below.

Figure 9-46: Total Portfolio Cost of Natural Gas for Gas Sales Temperature Sensitivity



F. No DSR

This portfolio looks at the benefits associated with demand-side resources.

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.

SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

Because the assumed total cost of natural gas supply has the greatest influence on portfolio costs and natural gas costs were high and relatively close in all scenarios, DSR produces significant savings. The approximate NPV benefit to the portfolio from DSR is about $500 million.

Stochastic Analyses

In order to test the portfolios developed in the deterministic scenario analysis under a wider range of demand and natural gas prices, PSE completed three stochastic runs in the GPM, with each run consisting of 250 draws:

1. **Resource/Cost Optimization**: This analysis tested the Mid Scenario deterministic portfolio against 250 variations (draws) of different demand and natural gas price combinations. The model was allowed to change the resource additions to optimize portfolio cost for the different demand and price conditions.
2. **No DSR Portfolio:** Starting with the Mid Scenario deterministic portfolio and the same 250 variations of demand and natural gas price combinations, this analysis removed DSR as a resource option to learn what other resources would be selected to fill need, and to compare the portfolio costs and risks of the No DSR portfolio with the portfolio optimized with DSR.
3. **Mid Fixed Portfolio:** This analysis tested the robustness of the Mid Scenario deterministic portfolio.The Mid Scenario final resource portfolio was fixed and then run through the 250 demand and natural gas price combinations to evaluate the portfolio's cost and reliability risks.

Development of Input Draws

The development of natural gas price draws and demand draws is the starting point for the stochastic analysis. Eighty natural gas price draws were developed using the risk functionality tool in the electric AURORA model, mirroring the gas price and demand draws used in the electric analysis. For the demand draws, the 250 draws that the load forecasting group used to develop the Low and High Scenarios were used.

NATURAL GAS PRICE DRAWS. For the Sumas, AECO, Rockies and Stanfield natural gas hubs, the natural gas stochastic analysis used the same 80 natural gas price draws developed for the electric stochastic analysis.[12] Natural gas prices for Station 2 and Malin were generated in the GPM using the basis differential pricing off one of the four hubs. The 80 draws were also repeated to create 250 draws. For each hub, a total of 19,200 prices (80 draws x 12 months/year x 20 years), were repeated to obtain 60,000 prices for each hub.

12 / The natural gas price draws were developed from the monthly forecasts that were used in the deterministic models, taking hub and lag correlations into account. See Appendix G, Electric Analysis Models, for a more detailed description of the methodology.

Each natural gas price draw was then adjusted to include the SCGHG and upstream emission adders in the GPM. Figures 9-47 and 9-48 below show the adjustment for Sumas hub for 2022 prices. With the addition of SCGHG and upstream emissions, the expected natural gas price shifted from $2.25/MMBtu to $7.57/MMBtu.

Figure 9-47: Sumas Price Draws for 2022 without SCGHG and Upstream Emission Adders

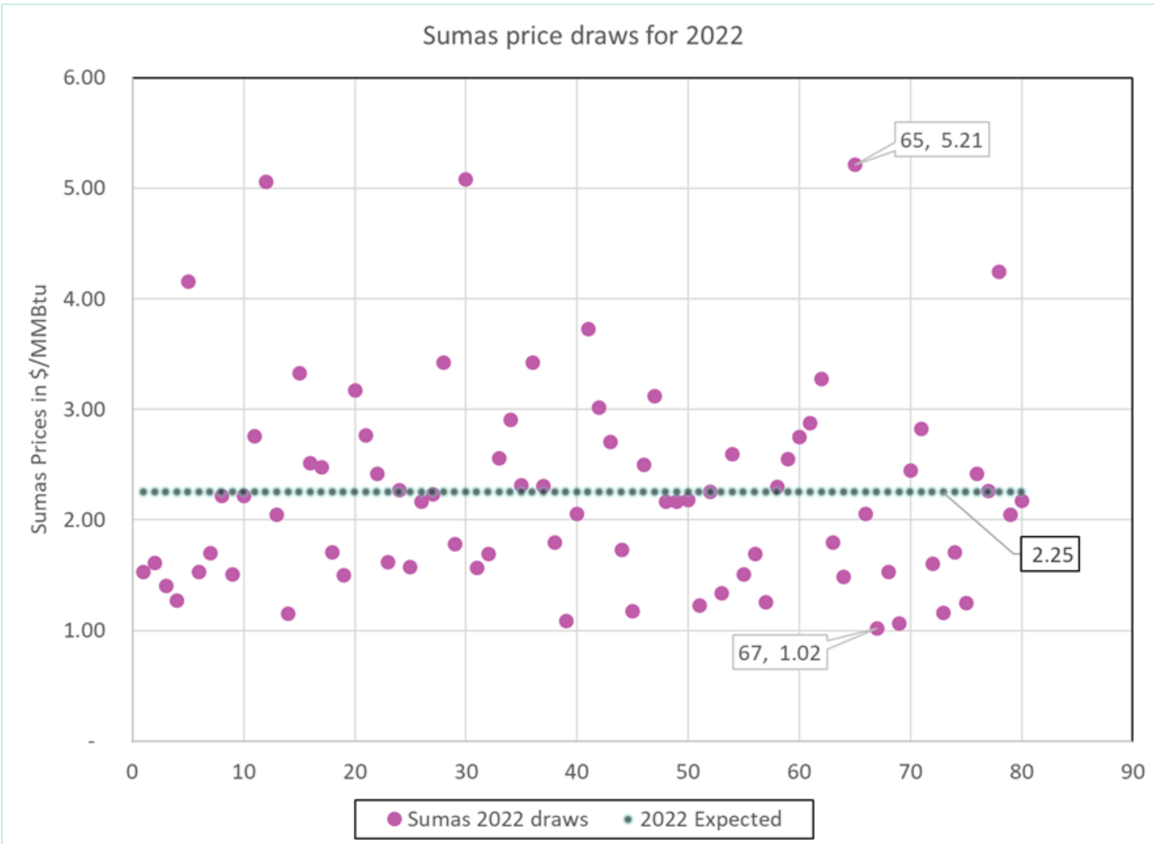
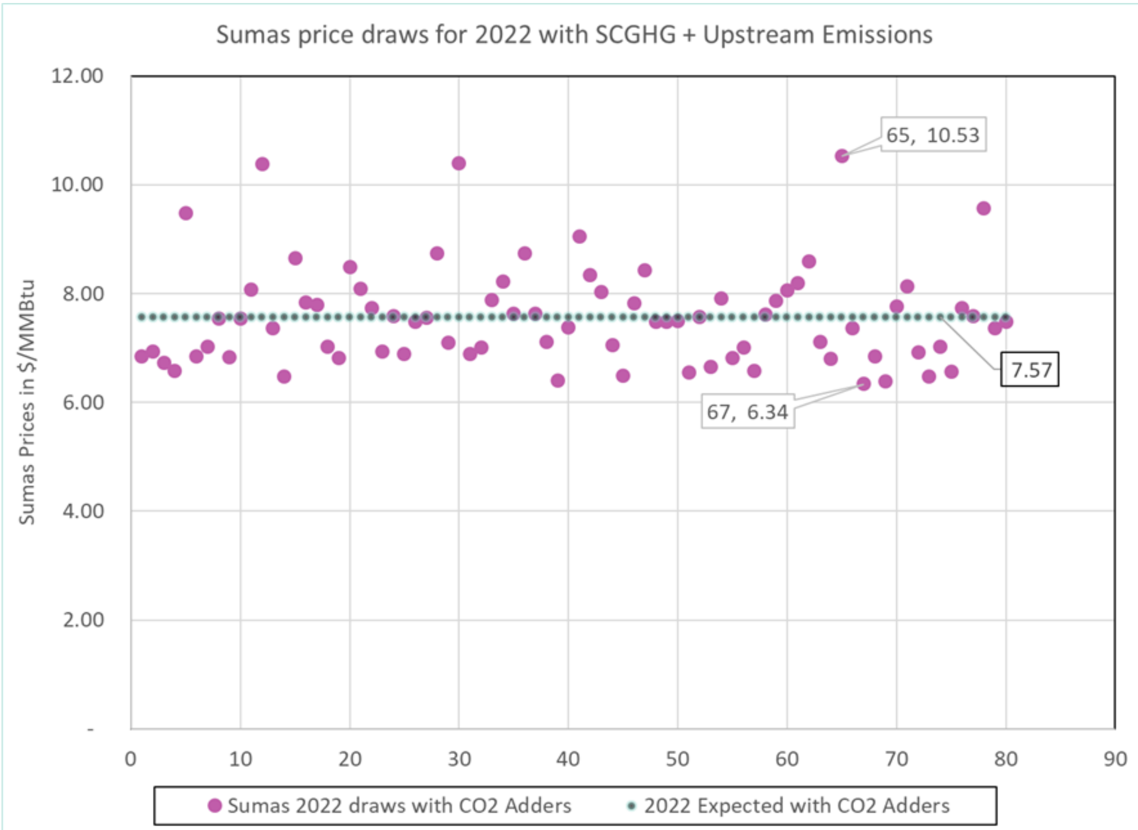
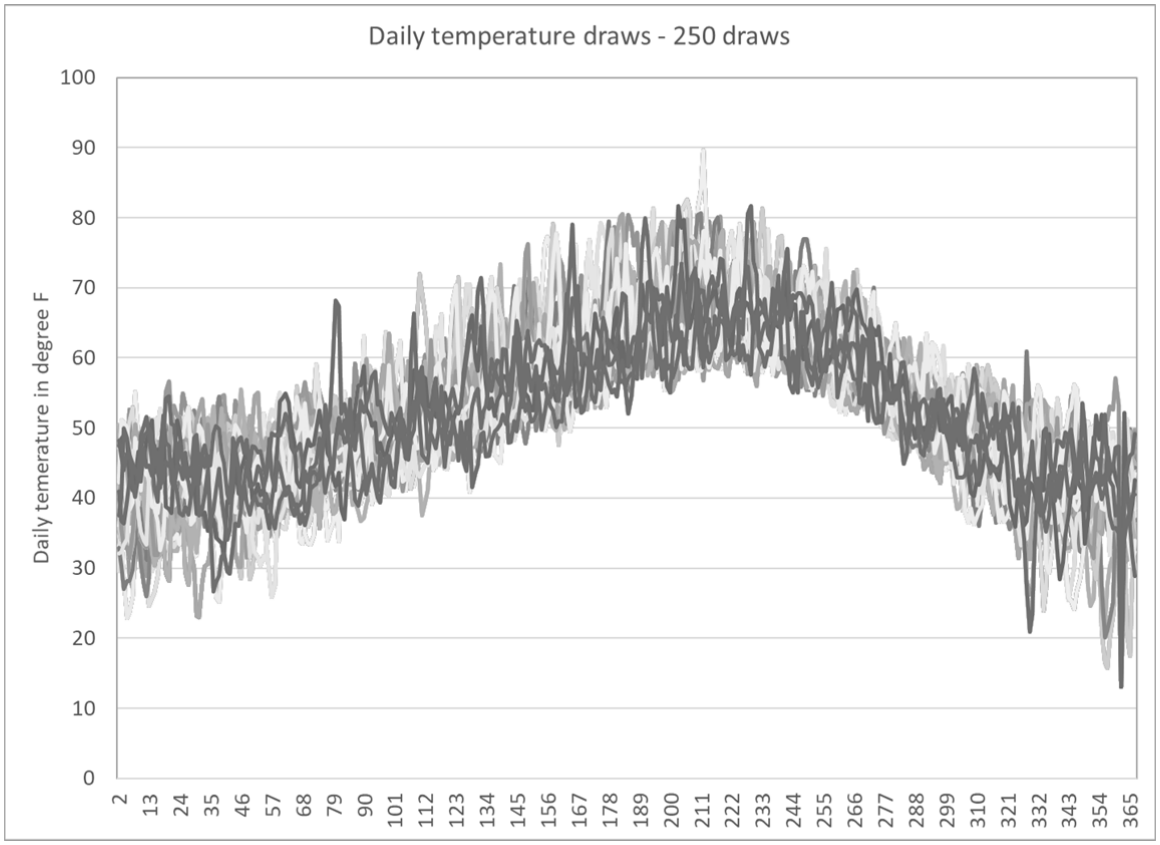


Figure 9-48 – Sumas Price Draws for 2022 after Adjusting for SCGHG and Upstream Emissions Adders



DEMAND DRAWS. The GPM uses temperature draws to calculate demand. The 250 demand draws were developed from the “normal” weather data used in the Base Demand Forecast, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019. Before the draws were imported into the GPM, they were adjusted to include the natural gas planning peak day temperature. Figure 9-49 below shows the temperature draws.

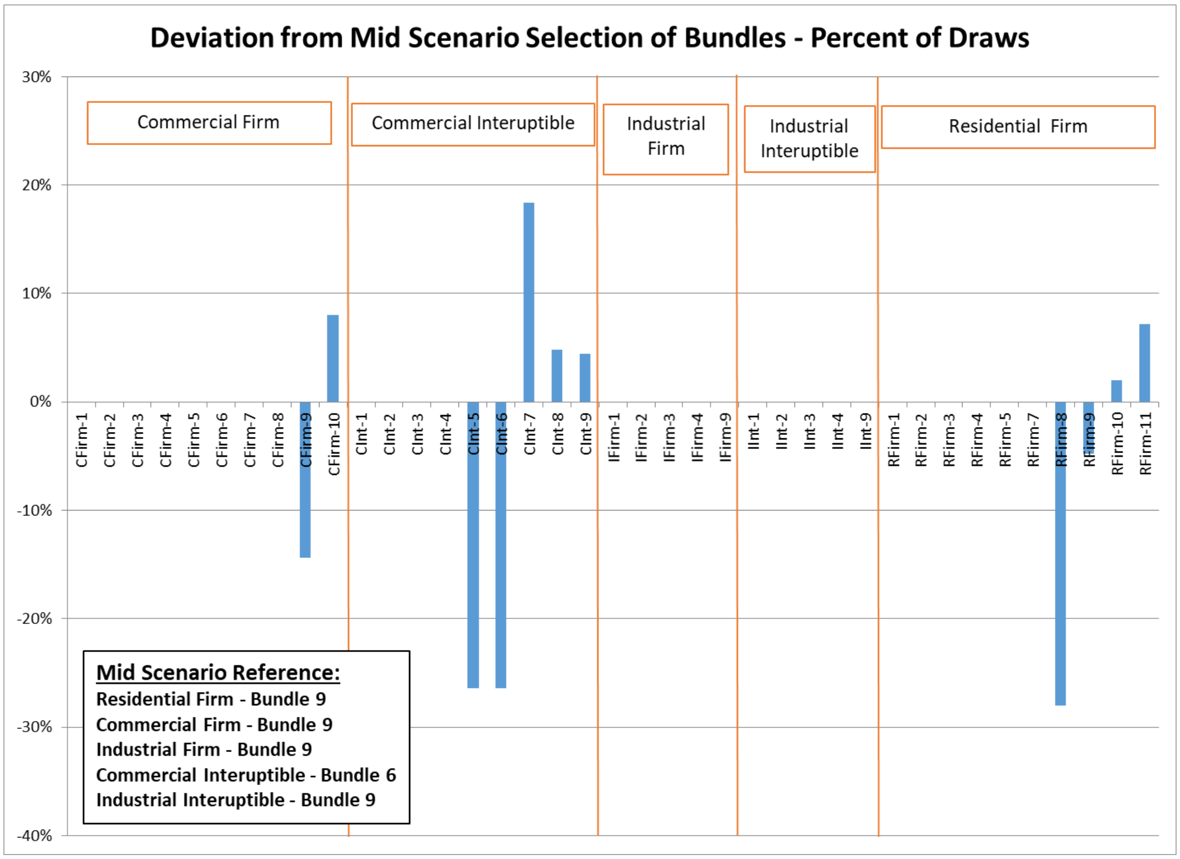
Figure 9-49 – Daily Temperature Draws for Demand



Stochastic Analysis Results

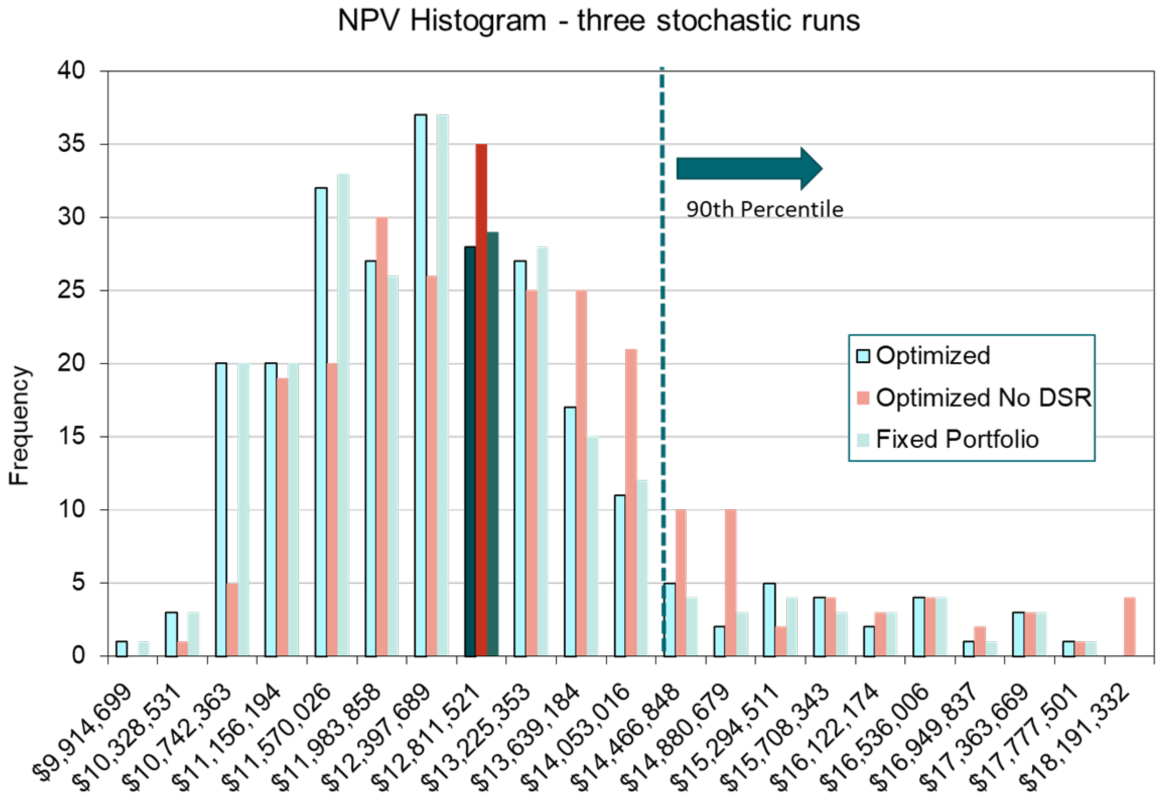
In the 250 optimal portfolios built in the stochastic analysis, the results showed that the DSR quantity chosen in the deterministic scenarios held up in over 80 percent of the draws as shown in Figure 9-50. Therefore, the risk of over-building or under-building DSR appears to be low.

Figure 9-50: Results of DSR Selection in the 250 Fully Optimized Portfolio Runs



The results of all three stochastic analyses are plotted in the histogram shown in Figure 9-51. The portfolio with No DSR has higher costs and more draws in the 90th percentile of total system cost, showing that DSR reduces both cost and risk to the natural gas portfolio.

Figure 9-51: Distribution of Portfolio System Costs



6. NATURAL GAS DELIVERY SYSTEM ANALYSIS

Overview

PSE's natural gas delivery system is responsible for delivering gas safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, PSE must do the following.[13]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at the local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Integrate natural gas supply resources owned by PSE or others.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

The goal of PSE's planning process is to fulfill these responsibilities in the most cost-effective manner possible. Through it, PSE evaluates system performance and bring issues to the surface; identify and evaluate possible solutions; and explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as integrity indices, company goals and commitments, and the root causes of historic events. External inputs include service quality indices, regulations, municipality infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended

13 / These obligations are defined by various codes and best practices such as WAC 480-90 Gas Companies - Operations; WAC 480-93 Gas Companies - Safety; WAC 480-100-358:398 Part VI Safety and Standard Rules; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; and Washington Industrial Safety and Health Administration.

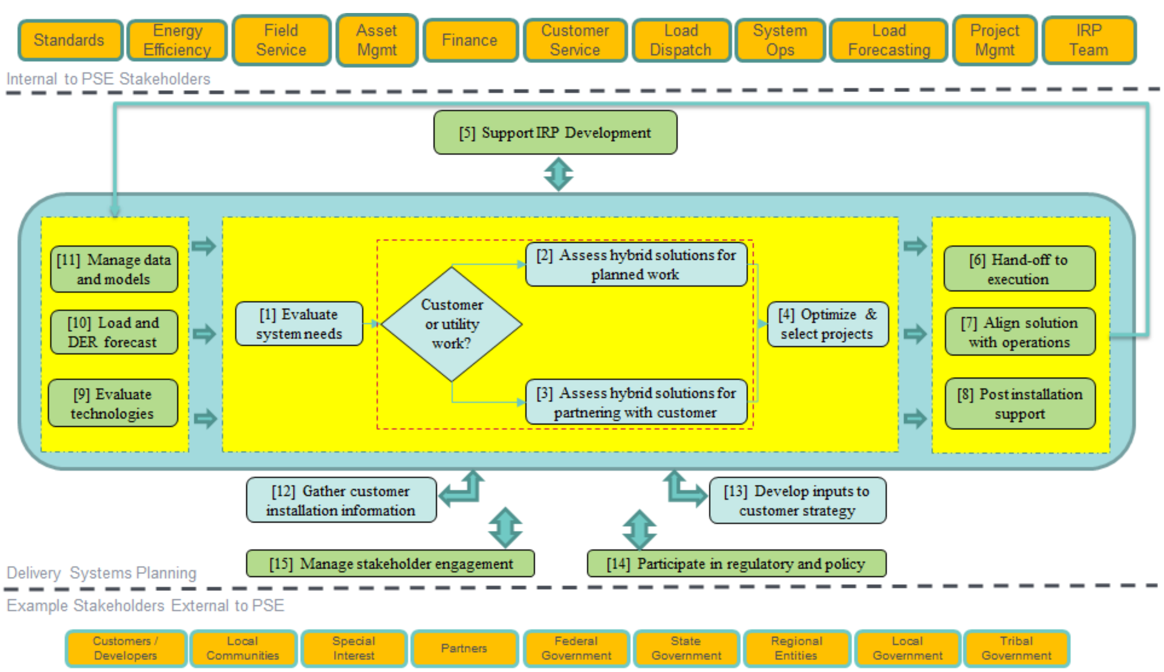
alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term and short-term planning. Typically, utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

> > > See Appendix M, 10-Year Delivery System Plan, for the Natural Gas System 10-year plan.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 9-52 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 9-52: PSE Delivery System Planning Operating Model



Natural Gas delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. Customer usage patterns determine the peak conditions that the natural gas delivery system must be designed to accommodate. PSE's natural gas load is primarily residential in nature, therefore, peak conditions align with cold-temperature weather events that occur during the winter months (November – March) each year. On a daily basis, the greatest draw on the system occurs between 4 AM and 8 AM, the four-hour period when most households begin their morning routine of waking up to a warm house, taking hot showers and cooking morning meals. It is during these high demand periods that the lowest pressure in the system occurs. Low system pressures that cannot support proper operation of customer equipment affects not only comfort, but safety concerns during a failure event. This requires the operator of the natural gas system to manually close each customer meter until proper pressures are reestablished, perform a safety check and relight each appliance, further inconveniencing the customer. As a result, the natural gas planning criteria is conservative with regard to both the minimum pressures allowed and the anticipated cold weather extremes. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new natural gas generation facility will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life create integrity issues potentially causing leaks or failure to operate when needed.

SYSTEM INTEGRITY. Pipeline and Hazardous Materials Safety Administration (PHMSA) require PSE to monitor and remediate risks to both the natural gas transmission and distribution programs.

OPERATIONAL FLEXIBILITY. The ability to isolate pipelines and transfer load, is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. While more commonly discussed in the context of the electric system, natural gas generators can impact demand as well and must be considered.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to ensure pipeline integrity and mitigate risk. Past leaks, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements mitigate elevated risks to the public and PSE's customers. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Per regulation, PSE has a robust distribution integrity management program and a transmission integrity management program that requires a risk based approach to identify and mitigating integrity concerns. Programs to address these risks are implemented, often resulting in the replacement of assets or increased monitoring. Programs are also in place to address aging infrastructure by replacing pipelines that are nearing the end of their useful life.

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy, are also included in the system evaluation. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement in 2012 allowing natural gas utilities to file a plan for replacing pipes that represent a higher risk of failure, and PSE's commitment to this plan is considered in the evaluation. In 2016, the NTSB recommended the pipeline industry develop guidance on safe pipeline operations to ensure protection of communities and the environment. The Pipeline Safety Management System (PSMS) helps operators understand, manage and continuously improve safety efforts at any stage of their safety programs through a Plan-Do-Check-Act cycle. The PSMS is intended to provide the tools needed to continuously and comprehensively track and improve safety performance. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As transportation projects develop through design, engineering and construction, PSE works with local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 9-53 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT,[14] which then creates a full understanding of all the benefits and risks.

Figure 9-53: Natural Gas Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
Synergi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS; load approvals; load forecast	Predicted system performance
Gas Outage Spreadsheet	Gas outage predictive analysis	Gas Synergi system performance data for future capacity	Predicted outage savings
Distribution / Transmission Integrity Management Risk Assessment	Gas pipeline risk analysis	Gas infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

14 / Investment Decision Optimization Tool which is a software tool called Folio by PwC.

PSE's natural gas system model is a large integrated model of the entire delivery system using a software application (Synergi® Gas) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system. For natural gas, this includes the diameter, roughness and length of pipe, connecting equipment, regulating station equipment and operating pressure. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual telemetry readings. Finally, we take into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 9-54. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission, bulk distribution (high pressure) and distribution (intermediate pressure), as well as for capacity[15] and reliability. A "need" is identified when performance criteria is not met.

15 / New methods of extracting and producing natural gas have accessed vast reserves of natural gas in the U.S. and North America. This has resulted in U.S. gas prices falling to levels not seen since the 1970s. In response to these depressed market prices, processing facilities no longer find it economic to strip out the heavier hydrocarbons (ethane, propane, butane, etc.) often found in raw natural gas. This has had the unexpected effect of increasing the Btu content[15] of the gas received from historic levels of 1,030 btu per standard cubic foot to more than 1,100 btu per standard cubic foot, essentially increasing system throughput capability by five to 10 percent, avoiding pressure and capacity concerns that need addressing. A change in gas quality (lower btu gas), while still within required tariffs, may result in more system analysis.

Figure 9-54: Performance Criteria for Natural Gas Delivery Systems

Gas delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (52 DD Peak Hour)
The nature of service each type of customer has contracted for (firm or interruptible)
The minimum pressure that must be maintained in the system (level at which appliances fail to operate)
The maximum pressure acceptable in the system (defined by CFR 192.623 and WAC-480-93-020)
The historical or future pipeline integrity performance indicators that elevate risk relative to safety or methane release which may be caused by aging infrastructure, third party damage, or equipment location or condition.
The ability to remove equipment from service for maintenance and provide flexibility for emergency response.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursuing electrification, demand side resources dependency at the local neighborhood level, and deferral of traditional infrastructure. PSE expects delivery system planning margins to increase to account for operating concerns relating to behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response, have historically incorporated outputs generically, but these assumptions, while appropriate for resource planning, may not be appropriate for local neighborhood decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE engages with WUTC pipeline safety staff in various forums such as annual audits and quarterly roundtable discussions that also inform PSE's considerations about concerns and solutions.

Solutions Assessment and Criteria

The alternatives available to address delivery system capacity, integrity, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 9-55: Alternatives for Addressing Delivery System Capacity and Reliability

ALTERNATIVES	NATURAL GAS SYSTEM
Add energy source	City-gate station; District regulator
Strengthen feed to local area	New high pressure main; New intermediate pressure main; Replace main
Improve existing facility	Regulation equipment modification; Uprate system
Load reduction	Conservation; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases.

PSE is monitoring and investigating technologies that will prove to be useful low carbon alternatives in the future including renewable natural gas injection into a needed location, hydrogen blending similar to renewable natural gas, greater use of demand response through smart thermostat technologies, and higher efficiency and hybrid or dual fuel customer equipment.

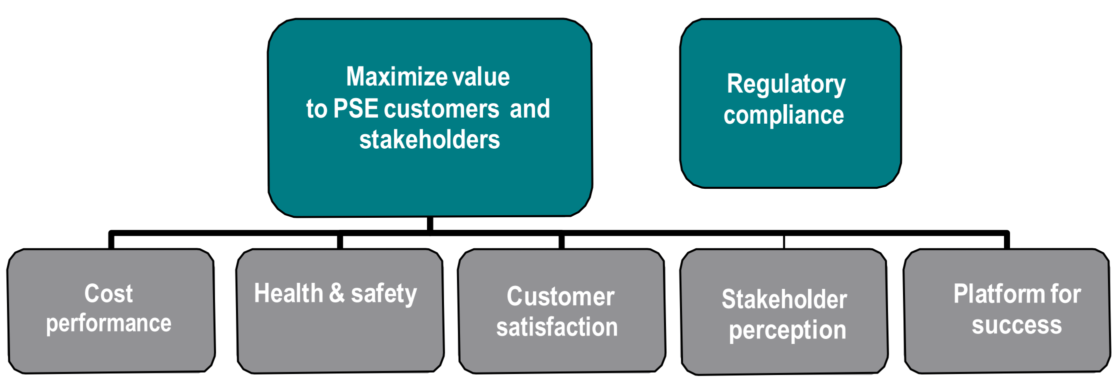
The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

- Temporary adjustment of regulator station operating pressure as executed through PSE's Cold Weather Action Plan
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles and liquid natural gas injection vehicles

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 9-55 as well as consideration of the avoidance of adverse impacts to integrity or operating characteristics and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to integrity, reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 9-56: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs for example particular vintages of wrapped steel and polyethylene facilities are prioritized for replacement based on known risks such as leakage history, pipe condition and the proximity of the pipe to certain structures.

iDOT builds a hierarchy of the value these benefits bring to stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project-specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary natural gas system infrastructure projects which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

Future iDOT enhancements could incorporate benefits such as carbon emissions reduction or methane emissions reduction benefit, more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100 percent clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric and natural gas energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. PSE’s delivery system planning process will mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-pipe Alternative Analysis

PSE's planning process has incorporated non-pipe alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-pipe alternative analysis is a screening process that breaks down of the problem utilizing existing resources, emerging technologies like renewable natural gas injection and hydrogen blending, or reducing customer demand, performs an economic and feasibility analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional pipeline solution, a full non-pipe solution, and any potential hybrid across the problem components.

All types of pipeline alternatives are considered, but some key facts must be considered:

- PSE has an obligation to serve existing natural gas customers within its certificate area approved by the WUTC.[16]
- PSE has an obligation to new natural gas service requests as long as a customer meets the tariff requirements,[17] and PSE is not authorized under Washington State to abandon its natural gas service for all, nor is it authorized to pay to electrify natural gas customers

With these facts as backdrop, PSE is committed to decarbonizing the natural gas system, pursuing greener energy and maximizing natural gas energy efficiency and the IRP highlights that opportunity to meet all future growth with demand side resources. Capacity needs may be able to be met with technologies such as demand response and more energy efficiency and understanding local customer behavior and adoption will be important to see these opportunities realized.

With the learnings of a more mature electric non-wire alternatives analysis, PSE has begun similar analysis in the natural gas system. More detail can be found in Appendix M.

16 / RCW 80.28.190
17 / RCW 80.28.110

Project Planning and Implementation Phase

Once the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that the total portfolio financial forecast remains within established parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through project lifecycle phase gates and through detailed routing and siting discussions.

Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive Plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.