GAS ANALYSIS

CHAPTER SIX

PUGET SOUND ENERGY

Contents

1. Introduction

This chapter explains the gas analysis we conducted for Puget Sound Energy's (PSE's) 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP).

2. Infrastructure Reliability

Gas transportation and distribution systems do not need the redundant capacity that electric distribution systems have because most gas infrastructure is underground, insulated from wind and storm damage. Equipment failure is rare, but it does occur, and there can be significant repercussions. For this reason, we build flexibility and resiliency into the system in four ways.

1. **A conservative planning standard:** Since we base PSE's peak day design standard on the coldest temperature on record for our service territory, and we do not often reach this extreme temperature, and it is even more rarely sustained, there is excess capacity in the system on most days.

2. **Cooperation with regional entities:** Members of the Northwest Mutual Assistance Agreement (NWMAA) utilize, operate, or control gas transportation and storage facilities in the Pacific Northwest (PNW) or represent major loads on the system. Members pledge to work together to provide and maintain firm service during emergencies and restore normal service to their customers as quickly as possible when such events occur. We applied the lessons learned from the October 2018 event discussed later in this chapter in the restructured NWMAA.

3. **Diverse transport resources**: Puget Sound Energy has built a gas transportation portfolio that intentionally sources gas equally from the north and south of our service territory to preserve flexibility during supply disruptions. We source approximately 50 percent of PSE's gas supply from Station 2 and Sumas to the north and 50 percent from the Alberta Energy Company (AECO) and the Rockies connected to the south.

4. **Gas storage:** Including gas storage in the portfolio via Jackson Prairie, Clay Basin, Gig Harbor LNG, and Tacoma LNG 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 PSE to purchase more gas in the typically less expensive summer season and can furnish gas supply in the event of a pipeline disruption.

The following two incidents illustrate how these strategies work in practice.[1] The Westcoast pipeline, between Station 2 and Sumas in central British Columbia (BC), ruptured in the early evening of October 9, 2018, shutting off gas flow from production points in northeast BC to Sumas for over 30 hours. This rupture resulted in the loss of more than 800,000 Dth per day of Sumas' supply. Coincidentally, the Jackson Prairie Storage Project was closed for scheduled maintenance. Coordinating their efforts through the NWMAA, all gas pipelines, utilities, power plant operators, and major industrial customers affected worked together to add supply or shed load. FortisBC, a large gas utility in southern British Columbia (BC), used some gas flowing on its pipeline from Alberta (Southern Crossing). Puget

[1] Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc.

Sound Energy, other utilities, and end-users took steps to reduce gas consumption or increase supply from their 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 BC 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 NWMAA members, the incident lasted less than 48 hours; however, the extensive testing and recertification required to restore the gas flow from BC to 100 percent of capacity took over a year. Westcoast was allowed to operate its system at 100 percent by mid-November 2019.

In February 2019, while the Westcoast pipeline was operating significantly below normal levels, the Jackson Prairie Gas Storage Project suffered a major compressor failure that reduced 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 gas from the storage facility had to purchase additional flowing supply from the market when supply was low and demand, and therefore prices, were high.

Although rare, these incidents demonstrate the resilience of the region's gas transportation and storage system and the importance of building resiliency and flexibility in the system to maintain reliability when incidents occur. Despite two significant failures, no firm residential or commercial customer was without gas, nor was there a loss of electrical service, which is increasingly dependent on the gas infrastructure. It is impossible to model random outages with our current modeling capabilities. However, these recent real-world experiences prove that PSE's steps to prepare for occasional infrastructure failure are successful.

3. Supply Adequacy

As noted, Puget Sound Energy intentionally sources gas from the north and south of our service territory to preserve flexibility during supply disruptions. We source fifty percent of PSE's gas supply from Station 2 and Sumas to the north and 50 percent from AECO and the Rockies connected to the south.

Puget Sound Energy holds firm capacity on Westcoast's system for approximately 50 percent of our needs from British Columbia to access 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 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 gas production in northeast BC increased substantially due to the shale revolution, a shortage of pipeline capacity 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.

After a recently completed expansion, Westcoast is again fully contracted. However, in 2027, the Woodfibre LNG export facility is expected to begin production, utilizing approximately 300,000 Dth per day of gas supply from the Huntingdon B. C. (Sumas) market. Woodfibre has acquired the firm Westcoast capacity necessary to serve their demand, and they will control their supply and destiny. The firm pipeline capacity they will use to access their gas supply currently provides adequate and occasionally abundant supplies to other customers at the Sumas market hub. Once Woodfibre LNG commences production of LNG for the export market, the supply available for other customers at Sumas on most days will be dramatically reduced.

Because there is currently an equilibrium of firm supply and firm demand in winter and a surplus in summer, PSE, and others active in the Sumas market, believe there is a risk for supply shortages at Sumas when Woodfibre begins operations in 2027.

As a result, there are three proposed pipeline expansions:

1. FortisBC Energy proposed an expansion and new route for its Southern Crossing Pipeline to bring additional supplies from Alberta to Huntingdon/Sumas. The primary driver for the project is Fortis's desire to obtain some diversity of supply routing as risk mitigation after the 2018 Westcoast Pipeline failure. We expect Fortis will move forward with this project, even if no additional shippers sign on. If built, Fortis would likely turn back some of its current capacity on T-South, likely obviating the need for Westcoast to expand its facilities.

2. Westcoast Energy held an open season for additional T-South (Station 2 to Huntingdon/Sumas). The cost of this expansion will have a significant upward impact on the rates PSE pays for service on Westcoast due to Canadian regulatory policy requiring rolled-in rate making. However, the incremental volumes should eliminate any potential for the shortfall. Puget Sound Energy and other Westcoast shippers will likely oppose the expansion of facilities if Fortis moves ahead on its project since capacity abandoned by Fortis could serve incremental demand on Westcoast. Also, the Vancouver market would be fully served, and no additional capacity is available on the Northwest Pipeline to move gas further south.

3. Northwest Pipeline has proposed a project to expand its capacity from Stanfield interconnect with Gas Transmission NW (GTN) west through the Columbia Gorge and north to Sumas. The project would have three purposes: move additional gas from Stanfield to the I-5 corridor and Huntingdon/Sumas for Fortis or others, and reduce displacement requirements along the Columbia Gorge, potentially creating additional southbound capacity from Sumas to Stanfield.

Details on all three of these projects are, at best, vague, but two things are certain: each is costly and will draw considerable attention in the decarbonization environment. We did not consider these projects in the current IRP because we are not actively pursuing additional pipeline capacity. However, we may consider joining a project if we obtain more favorable capacity without imposing high costs or risks on PSE customers. Any of these projects would likely alleviate concerns over the reliability of the supply market at Huntingdon/Sumas.

We are confident we can acquire adequate supplies at Sumas; however, we expect prices to be higher under cold-weather conditions.

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

3.1. Recommendations

No actions are currently needed. We are not studying the pipeline expansion projects discussed in the prior section in this 2023 Gas Utility IRP for the following reasons:

- Costs for each project are extremely high.
- Puget Sound Energy has sufficient capacity on the Northwest and Westcoast pipelines.
- Puget Sound Energy's declining demand does not justify additional capacity to city-gate.
- Regional demand does not justify expansion beyond Fortis' new line.
- We could assure greater access to Station 2 by taking some of Fortis's excess Westcoast pipeline capacity and alleviate any concerns at Sumas.

4. Resource Need

Peak day demand drives PSE's gas sales, which occurs in the winter when temperatures are lowest, and heating needs are highest. The current design standard ensures that we plan PSE supply to meet firm loads on a 13° design peak day, corresponding to a 52-heating degree day (HDD).[2] Two primary factors influence demand — peak day demand per customer and the number of customers. The heating season and the number of lowest-temperature days in the year remain relatively constant, and use per customer is growing slowly,[3] so the most significant factor we currently utilize to determine peak load growth is the increase in customer count.[4]

This 2023 Gas Utility IRP analysis modeled two customer demand forecasts over the 27-year planning horizon: the 2023 Gas IRP Mid-(reference) demand forecast and the 2023 Gas Utility IRP zero-growth demand forecast.[5] We tested whether we needed to renew existing pipeline contracts in both cases.

In the zero-growth demand forecast, we have sufficient firm resources to meet peak day need throughout the study period if we assume we will automatically renew existing pipeline contracts. Without pipeline renewals, we will need more resources in the winter of 2025–2026.

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[2] Heating degree days (HDDs) are the number of degrees relative to the base temperature of 65° Fahrenheit. A 52 HDD is calculated as 65° less the 13° temperature for the day.

[3] The 2023 demand forecast incorporates climate change. Although energy consumption declines over the IRP study period, the peak day forecast did not change with this update. See Chapter Four: Key Analytical Assumptions for more detailed discussion of the demand forecast.

[4] The 2021 Gas Utility IRP demand forecast projects the addition of approximately 9,000 natural gas sales customers annually on average.

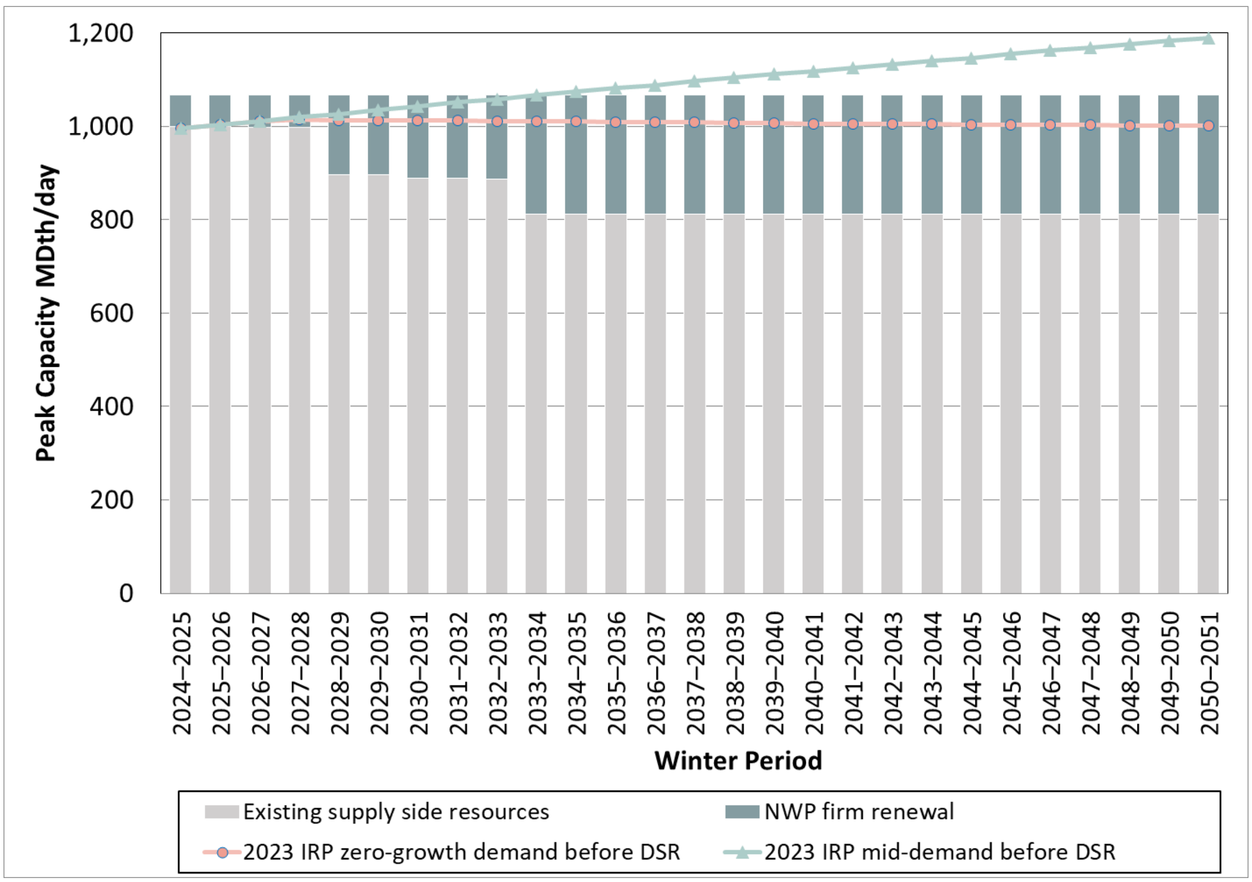
[5] The zero-growth demand forecast consists of no new customers after 2026. We discuss the 2023 Gas Utility IRP demand forecasts in detail in Chapter Five: Demand Forecasts.

In the Mid-(reference) demand forecast, the first resource need occurs in the winter of 2030–2031, assuming we renew existing pipeline contracts. If we assume no pipeline renewals, the need arises in the winter of 2025–2026.

Figure 6.1 illustrates the gas sales peak resource need over the 29-year planning horizon for the two demand forecasts modeled in this IRP. Figure 6.2 shows the resource need surplus or deficit for the Mid-demand forecast.

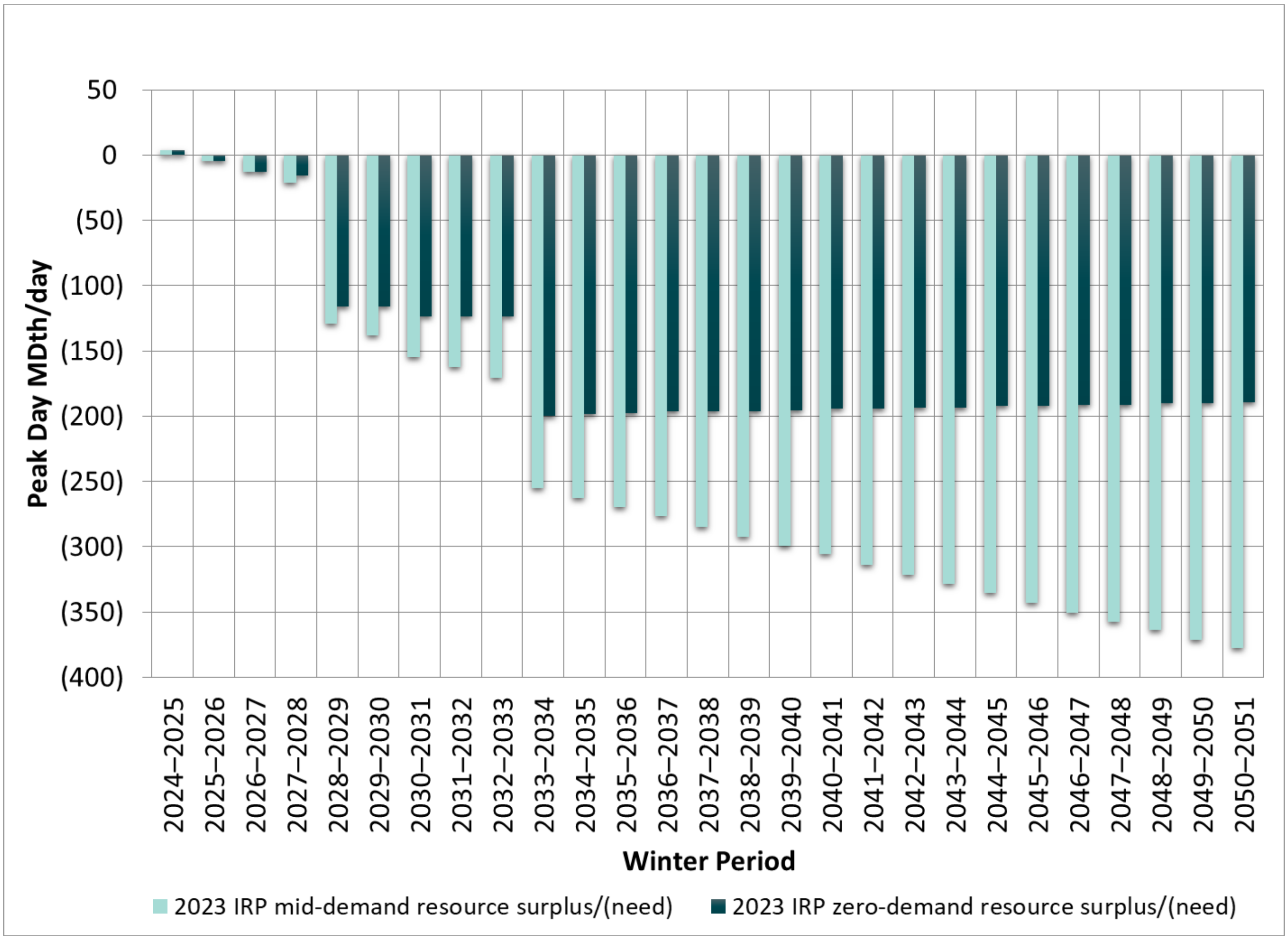
In Figure 6.1, the lines rising toward the right indicate peak day customer demand before additional demand-side resources (DSR),[6] and the bars represent existing resources for delivering natural gas supply to our customers. These resources include contracts transporting natural gas on interstate pipelines from production fields, storage projects, and on-system peaking resources. We also show contract expirations and renewals. If demand declines or we have significant surplus resources, we will evaluate whether pipeline renewal or release makes sense for the gas sales portfolio. We will also consider if lower-cost resources can replace year-round pipeline capacity and reliably serve customers. The gap between demand and existing resources is the resource need.

Figure 6.1: Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand



[6] 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.

Figure 6.2: Gas Sales Peak Resource Need Surplus/Deficit
in Mid- and Zero-demand Forecast before Pipeline Renewals and DSR



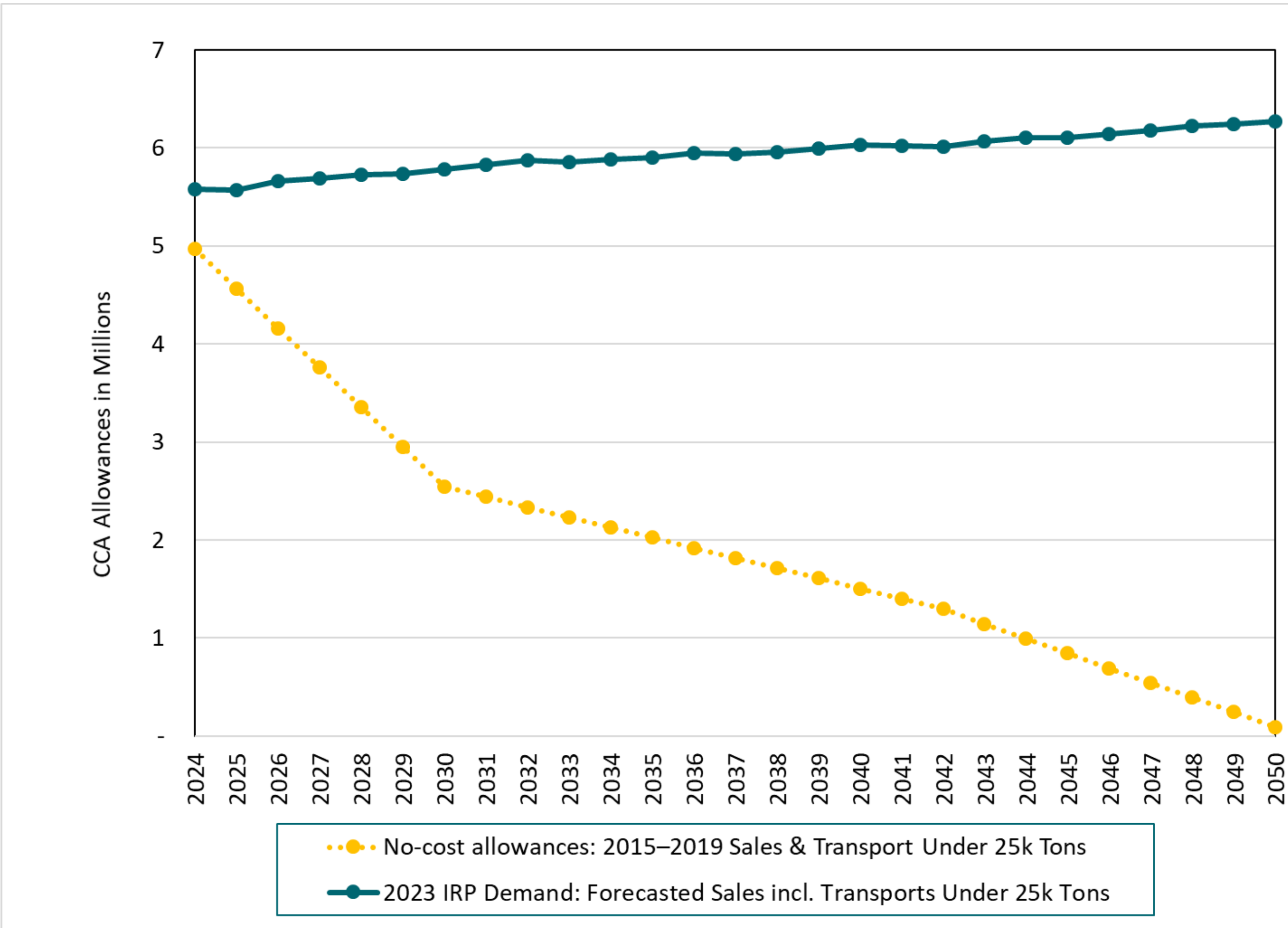
5. Climate Commitment Act

In 2021 the Washington State Legislature passed the Climate Commitment Act (CCA), which created a cap and invest program to reduce carbon dioxide emissions within specific sectors of the economy, including gas utilities. The program rules, developed by the Department of Ecology (Ecology), went into effect on January 1, 2023. The final rules were proposed on September 29, 2022, and adopted on October 30, 2022.

➔ For details on the CCA, please refer to Chapter Three: Legislative and Policy Change.

This 2023 Gas Utility IRP draws on the rulemaking documents to establish the emissions baseline and allowance[7] allocation forecast. This report uses the CCA allowance price forecasts to determine the cost of compliance in various scenarios and sensitivities described later in this chapter. We show the no-cost allowances for PSE in Figure 6.3. We show allowance data throughout this chapter to distinguish between no-cost allowances and net additional allowances.

Figure 6.3: Gas No-Cost Allowance Forecast (Department of Ecology, September 29, 2022)[8]



6. Risks to Natural Gas Supply

Suppliers import natural gas to the Pacific Northwest, mainly from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure present a risk to reliable gas supply in the area.

The Enbridge Westcoast Energy pipeline failure in October 2018 highlighted how heavily the utility FortisBC and the British Columbia Utilities Commission (BCUC) relied on the pipeline for supply from the northeastern portion of

7 Allowance is an authorization to emit up to one metric ton of carbon dioxide equivalent.

8 The no-cost allowances line is based on the gas sales customers plus transport gas customers with emissions less than 25,000 tons per year. We removed Emissions Intensive Trade Exposed (EITE) gas sales customers from the gas sales to calculate the no-cost allowances line.

British Columbia. Concurrently, natural gas utility Woodfibre LNG announced a final investment decision and a partnership with Enbridge (Westcoast pipeline's parent company) to build and operate an export facility. Woodfibre gas demand will pull 300 MDth/day out of the Sumas market hub using previously acquired firm capacity. The Woodfibre capacity on the Westcoast pipeline brought 300 MDth to the Sumas market daily; without it, Sumas may become less liquid, very volatile, and may experience supply shortages on some days. This situation has produced a growing concern over the availability of uncommitted gas at Sumas when Woodfibre starts up in 2027. As discussed in the previous section, the Westcoast pipeline and Northwest Pipeline have proposed expansions to their systems.

7. Delivery System Planning

Puget Sound Energy uses delivery system planning to ensure the pipeline delivery system can deliver gas safely, reliably, and on demand. We must also meet all regulatory requirements that govern the system and ensure we build equity into planning analysis.

The objectives of energy delivery system planning are to:

- Be prepared for and deliver service through various operating models, including leveraging behind-the-meter assets, acting as an owner-operator, and partnering with third parties and customers.
- Be transparent about decision-making and processes in collaboration with external stakeholders and customers.
- Deliver flexible, segmented, and tailored value propositions that meet our customers' needs.
- Ensure we embed equity and affordability in planning and decision-making.
- Improve system performance making it more safe, reliable, resilient, smart, and flexible at optimal cost.
- Incorporate new technology and solutions to meet system needs, including non-pipe alternatives (NPA).
- Operate and maintain the system safely and efficiently daily, annually, and in real-time with all fuels.
- Prepare for and deliver lower carbon fuels to customers, including renewable natural gas (RNG) and hydrogen-blended natural gas.
- Proactively identify trends and influence regulatory and legislative policy to help achieve the above objectives.

Meeting system needs and PSE's decarbonization goals requires a flexible planning framework, a modern energy delivery system, a focus on research, and continuous improvement.

→ For more details on our delivery system planning model and 10-year investment strategy, see Appendix G: Delivery System Planning.

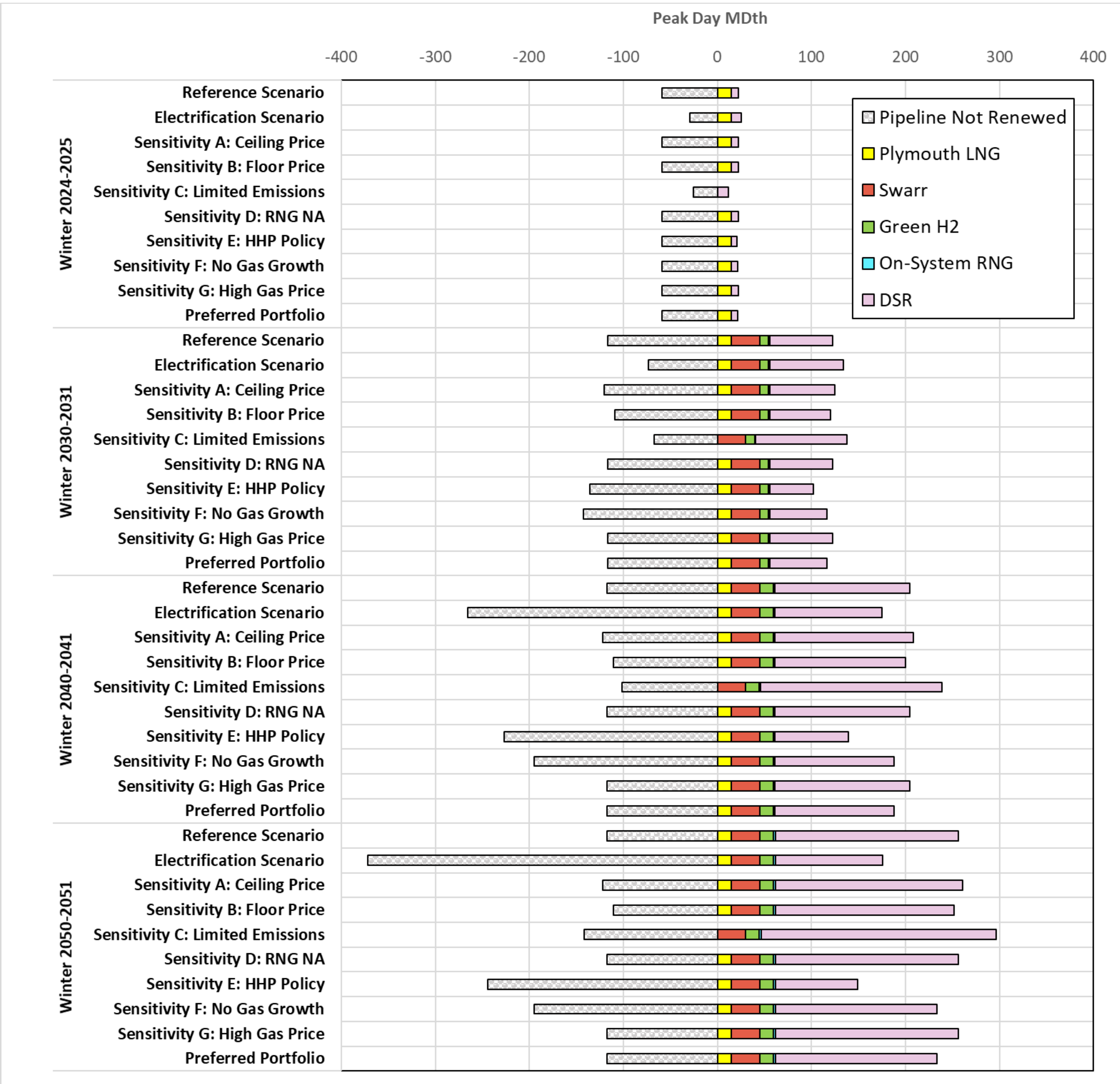
8. Gas Sales Analysis Results

This section discusses the results of the gas portfolio modeling that looked at the scenarios and sensitivities outlined in Chapter Four: Key Analytical Assumptions. We discuss critical findings under resource additions, followed by details of the scenarios and sensitivities.

8.1. Resource Additions: Scenarios and Sensitivities

In this section, we discuss the deterministic runs for each scenario and sensitivities in SENDOUT, the gas portfolio model and summarize the results in Figure 6.4. We also review some of the key findings from the results.

Figure 6.4: Resource Additions by Scenarios and Sensitivities



The following key findings from this evaluation will guide us as we develop PSE's long-term resource strategy and provide background information for resource development activities over the first two years of the study period.

- Cost-effective energy efficiency does not vary much across several sensitivities. Therefore, there is a reduced risk of overbuilding or underbuilding this resource. The zero-growth gas sensitivity does not decrease the cost-effective energy efficiency savings from the reference scenario based on a mid-growth demand.

- Emissions reductions are relatively small in all scenarios and sensitivities except those where the emissions are physically constrained not to exceed the amount covered through no-cost allowances. Green hydrogen is cost-effective in all scenarios and sensitivities when considering the benefits of production tax credits (PTCs) under the Inflation Reduction Act (IRA) of 2022.
- In the reference scenario, the natural gas sales portfolio is short of resources beginning in winter 2031–2032 and each year after. In contrast, the zero-growth sensitivity is long (has no resource need) over the entire study period.
- Renewable Natural Gas (RNG) is price sensitive, and more of it is cost-effective in the scenario and sensitivities with carbon constraints or the higher ceiling CCA allowance price. Renewable Natural Gas (RNG) sourced from North America could triple the cost-effective amount in the price sensitivities with higher ceiling CCA allowance costs compared to regionally constrained RNG.
- In the reference scenario, we met resource needs primarily with energy efficiency. The increased cost of gas drives cost-effective energy efficiency higher on the 2023 supply curve than in the 2021 Gas Utility IRP. The amount, or physical volume of cost-effective energy efficiency, is about the same as in the 2021 Gas Utility IRP.
- In all scenarios, some pipeline capacity that is up for renewal before the 2033 period is not renewed and instead displaced with energy efficiency and peaking resources from the Swarr and the Plymouth liquid natural gas (LNG) plants.
- The Swarr and the Plymouth LNG plants are cost-effective across most sensitivities.
- The total gas costs are higher due to the added CCA allowance price. Price adders for greenhouse gas emissions quadrupled the total cost of the gas on the margin: SCGHG with upstream emissions and CCA allowances.[9]

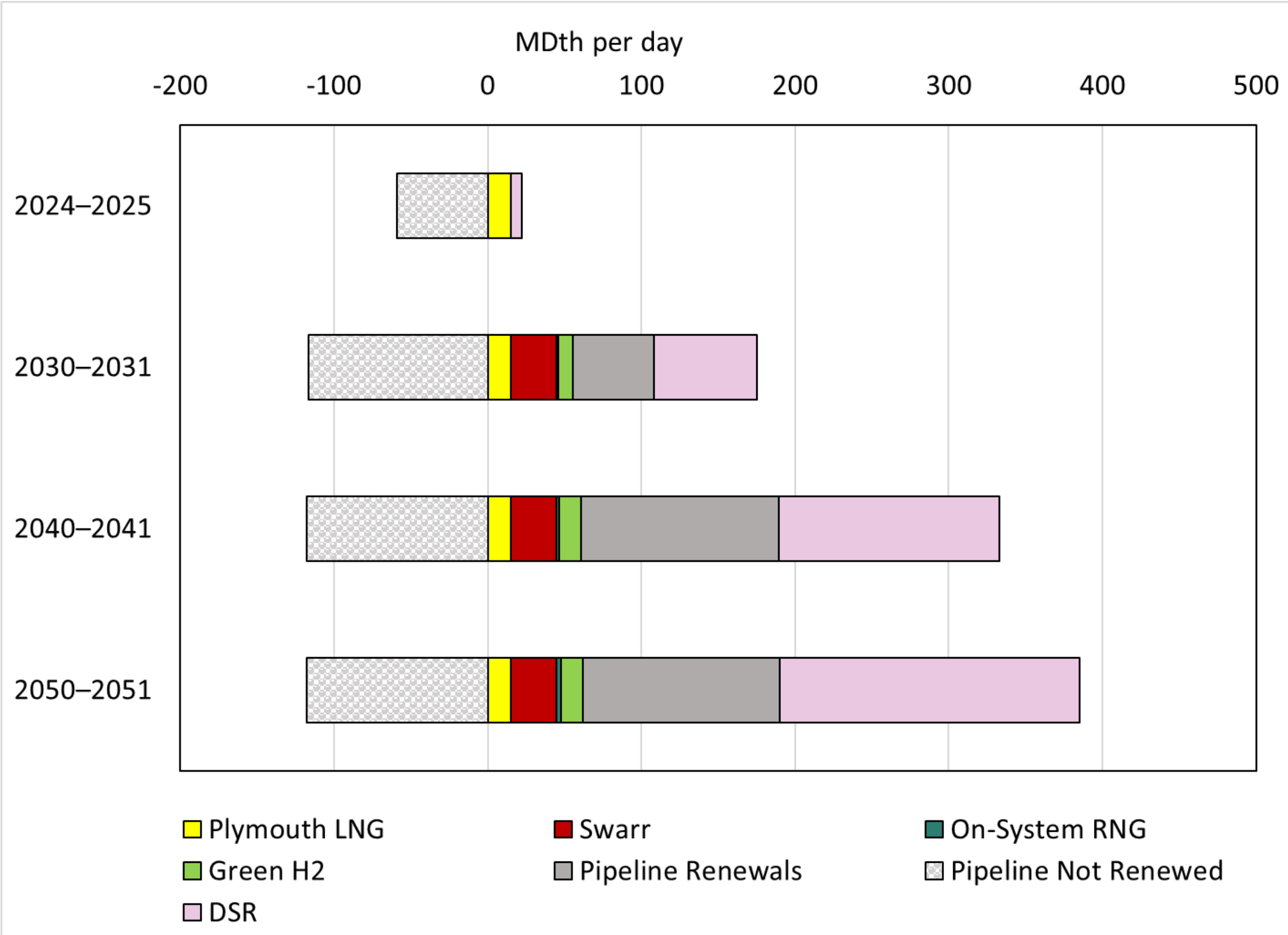
8.2. Reference Scenario

The reference scenario is the less constrained of the two scenarios where we optimized inputs in the gas portfolio model. We modeled two resource options on the demand side: energy efficiency and hybrid heat pumps (HHP). We input both supply curves in the gas model. Since the HHP supply curve has an electrification component, any cost-effective capacity additions would demand the energy efficiency supply curve be adjusted and reiterated through the model. But the results show that the HHP is not cost-effective, so no such iteration was necessary.

Similarly, a cost-effective HHP selection would have also led to an iteration to determine the electric load build and incremental energy efficiency associated with the load build for a corresponding electric analysis to identify the resources needed to serve the additional electric load. But since we did not select any HHP in the gas model, no electric analysis was triggered. We show the results of the reference portfolio resource builds for our gas portfolio analysis in Figure 6.5.

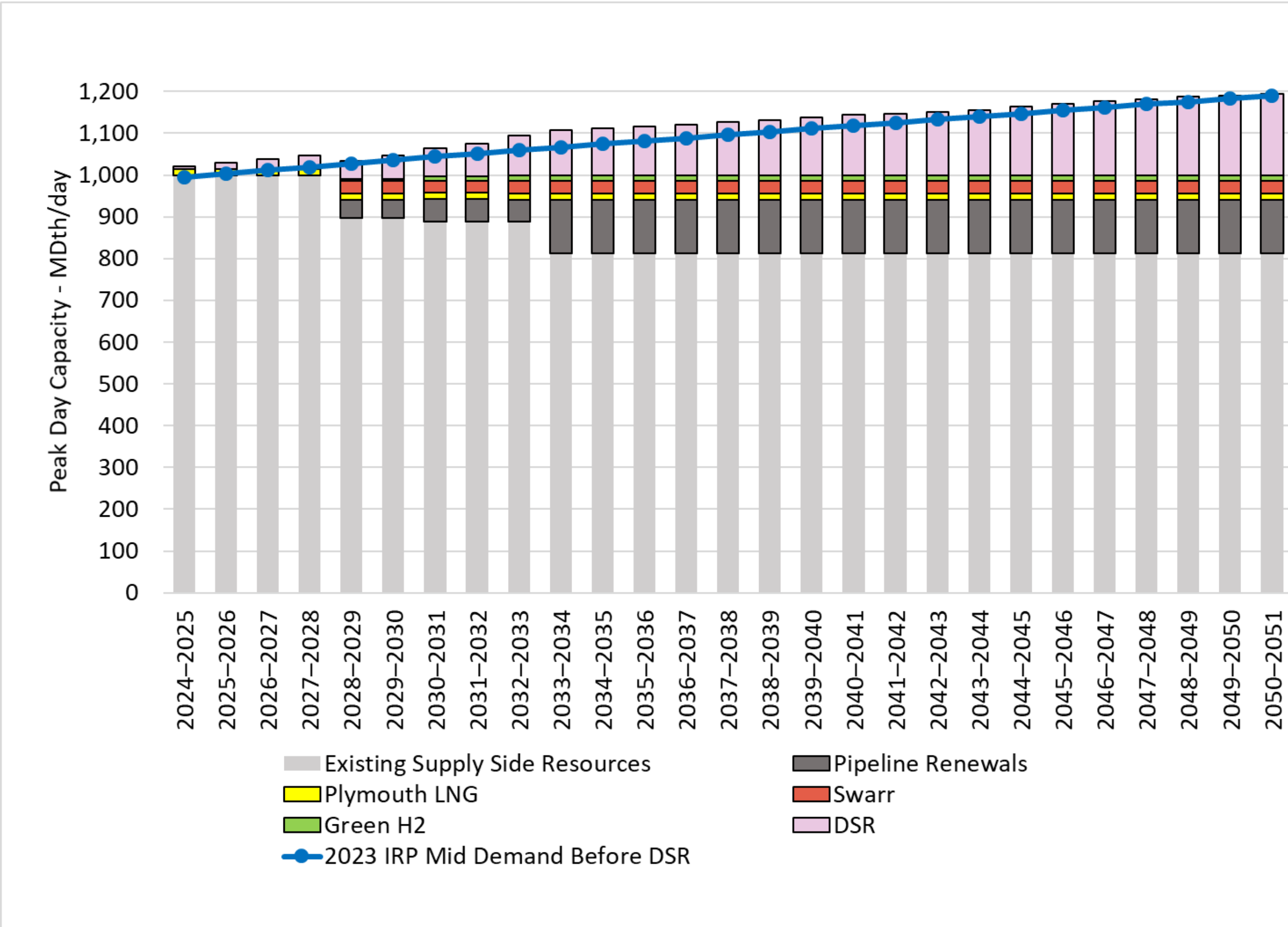
[9] The 20-year levelized cost of gas from Sumas is approximately $3.70. With the carbon adders, the total cost approaches $16.00. See Chapter Four for additional discussion on how we developed the gas costs used in the 2023 Gas Utility IRP analysis.

Figure 6.5: Scenario One: Reference Portfolio Resource Additions — Peak Day



We show the resource additions for our gas portfolio analysis in Figure 6.6

Figure 6.6: Resource Additions by Type and Period



Conservation was a significant resource addition impacted by the higher total gas costs and marginal avoided capacity of the pipeline renewals. As a result, the model chose not to renew some of the pipeline capacity contracts. The other resources displacing the pipeline contracts were Plymouth LNG and Swarr, which were more cost-effective than paying for year-round pipeline capacity.

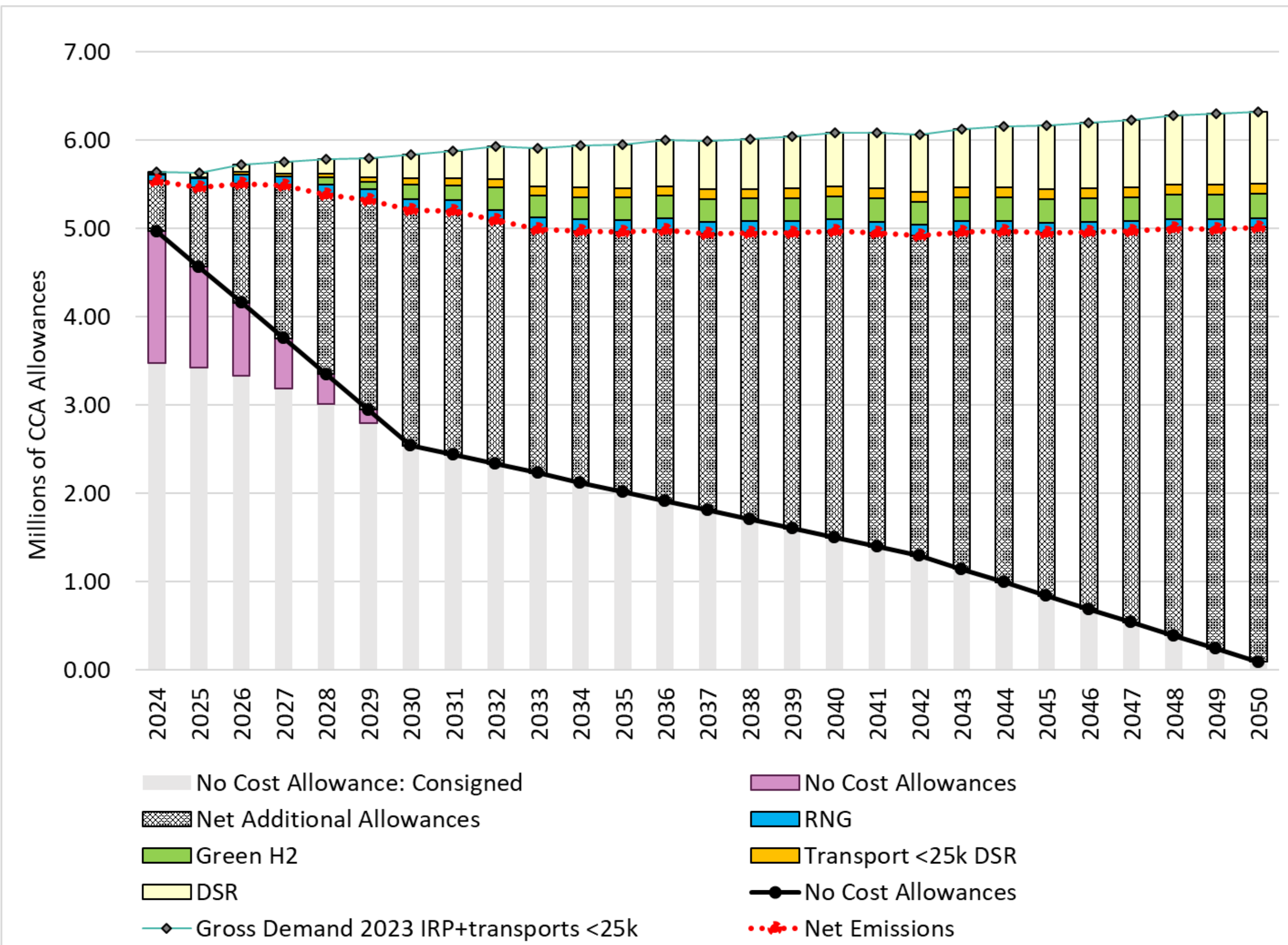
We modeled two alternate fuels for the gas portfolio, RNG (biomethane fuels) and green hydrogen. These options were limited to the Pacific Northwest (PNW), which impacted the RNG potential; casting a wider net throughout North America would make significantly more RNG available to the gas model. Total gas costs with the expected CCA allowance price are slightly less than most regional RNG. Therefore, most of the regional RNG was not cost-effective, except for the contract on the PSE system, which avoids the added pipeline transport costs. Hence, the model selected only one contract with this characteristic.

The model selected green hydrogen, a resource aided by the PTCs offered through the IRA, in 2028, when it will be available, and all the subsequent additions in 2030 and 2032. The regional limitation in this report did not impact green hydrogen because we only considered a PSE system resource. Regional sourcing may become an issue in future IRPs if cost-effective green hydrogen resources are only available outside the PNW.

According to the analysis, the gas system is long if we renew all the existing pipeline contracts. If we treat pipelines as a resource that competes with other options for renewal to determine the least cost option, the model only renews some of the pipeline capacity offered for renewal. In the reference scenario, most of the Rockies hub segment is not renewed. This pipeline capacity is replaced with conservation and needle peaking alternatives: the Swarr propane plant and capacity on Plymouth LNG with associated pipeline capacity for delivery to the PSE system.

We show the reference scenario emissions reductions in conjunction with the CCA-no-cost allowances in Figure 6.7. Energy efficiency[10] is the most significant contributor to emissions reductions, followed by green hydrogen and on-system RNG, which is too small to be visible on the chart. Purchased CCA allowances are the most cost-effective option for meeting the remaining CCA emissions compliance obligations at the expected price. In this scenario, the physical emissions are reduced by seven percent in 2030 compared to the emissions in 2023, at the start of the first compliance period, and reduced by 10 percent in 2045. We achieve the remaining compliance obligation through the purchase of CCA allowances.

Figure 6.7: Emissions Reduction Reference Scenario



[10] The chart shows emissions reductions from energy efficiency related to the transport customers. We estimated these reductions using PSE avoided costs as a proxy because we do not know the avoided costs for the transport customers.

8.3. Gas Portfolio Sensitivities

Sensitivities start with the optimized, least-cost reference scenario portfolio produced in the scenario analysis. We change a single resource, environmental regulation, or other condition to examine the effect of that variable on the portfolio. We summarized the sensitivities in Table 6.1 and described them in the following sections.

Table 6.1: 2023 Gas Utility IRP Sensitivities

#	Sensitivity Name	CCA Constraint Parameter	CCA Allowance Price	Renewable Fuel Source location	SCGHG Added?	Demand**	Gas Price**
1	Reference Case	Price	Mid	PNW	No	Mid (F22)	Mid
A	Allowance Price High	Price	Ceiling*	PNW	No	Mid (F22)	Mid
B	Allowance Price Low	Price	Floor*	PNW	No	Mid (F22)	Mid
C	Limit Emissions Without Regard to Price	No-Cost Allowance Line*	Floor*	PNW	No	Mid (F22)	Mid
D	Alternative Fuel Location WA	Price	Mid	North America*	No	Mid (F22)	Mid
E	HHP Policy	Price	Mid	PNW	No	Mid (F22) - policy-driven HHP adoption*	Mid
F	Zero gas growth	Price	Mid	PNW	No	Zero gas growth after 2026*	Mid
G	High Gas Price	Price	Mid	PNW	No	Mid (F22)	High*

Notes:

* Indicates change as compared to the reference case

** Typical Gas IRP parameters

A — CCA Allowance Price High

This sensitivity tests the impacts of a high ceiling allowance price.

Baseline Assumption: We used the mid-CCA allowance price.

Sensitivity: We applied the ceiling allowance price provided by the Department of Ecology (Ecology)[11] in this sensitivity.

Portfolio Results:

- The high allowance price makes all the regional RNG offered cost-effective, including on-system, delivered contracts, and RNG products that are unbundled regional attributes available at the early part of the study. These offerings, except for the on-system RNG, were not cost-effective in the reference scenario, and this

[11] https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf page 9

sensitivity shows that if allowance prices are higher, acquiring RNG is a cost-effective way to reduce emissions to achieve CCA compliance.

- The higher allowance price also selected slightly more energy efficiency in the portfolio model. The peak contribution was higher by 4 MDth[12] a day on peak day by 2050.

B — CCA Allowance Price Low

This sensitivity tests the impacts of a low allowance price.

Baseline Assumption: We applied the mid-CCA allowance price.

Sensitivity: We applied the floor allowance price as provided by Ecology[13].

Portfolio results

- The floor allowance price lowers the total cost of conventional gas; thus, this portfolio renews slightly more pipeline capacity or retains more existing pipeline capacity compared to the reference portfolio.
- The lower total gas costs also result in lower energy efficiency being cost-effective, lower by 5 MDth (50,000 therms) a day in 2050.

C — Limiting Emissions Without Regard to Price

This sensitivity minimizes greenhouse gas emissions with the resource options in the gas model before it purchases above the no-cost allowance trajectory under the CCA to fill the gap with additional allowance purchases at the floor price. It is essential to call out that this parameter is theoretical; the current CCA policy requires Ecology to offer allowances. Sensitivities limited by emissions do not reflect the least-cost approach.

Baseline Assumption: We applied the mid-CCA allowance price and allowed for the purchase of net additional allowances to meet compliance.

Sensitivity: We first forced the emissions to be minimized with the resource options and then balanced the remaining gap between the no-cost allowances and the reduced emissions by purchasing net additional allowances at the floor price.

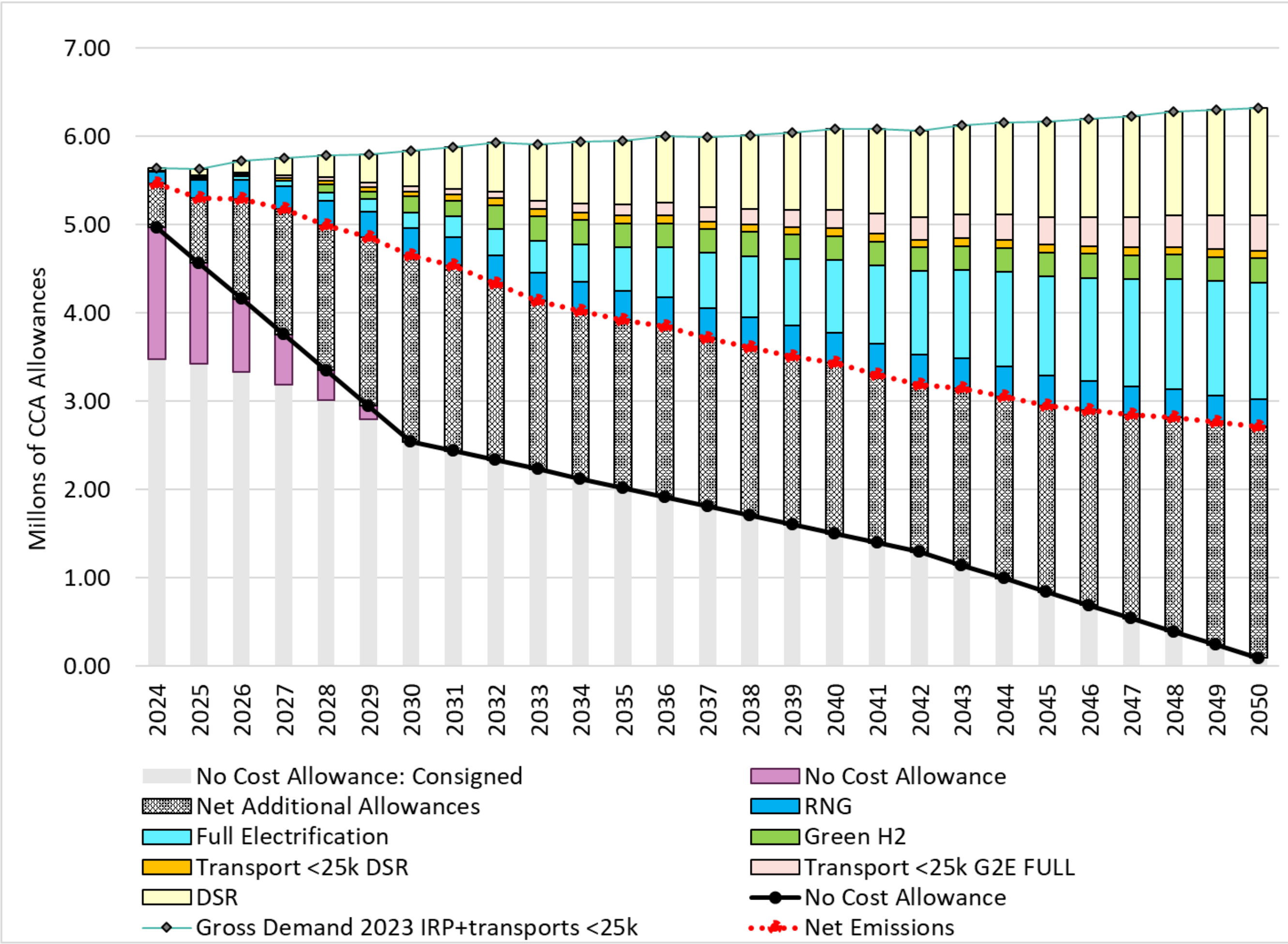
Portfolio results:

- The maximum amount of alternate fuels is selected and contributes to reducing emissions.
- The physical limit on emissions to the no-cost allowance trajectory maximizes the resource additions to reduce the emissions to attain the emissions target; there are not enough resources available, especially in the early years. That gap eventually must be filled with the purchase of CCA allowances at the floor price.
- The portfolio selects all the energy efficiency; this is the second largest reduction in emissions.
- The portfolio selects all the hybrid heat pumps in the market-driven supply curve. These hybrid heat pumps reduce emissions significantly and are the most significant contributor to reducing emissions, see Figure 6.8.

[12] One MDth is equal to 10,000 therms.
[13] https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf

- Compared to the baseline emissions from 2015–2019, the total reductions are 22 percent lower in 2030 and 79 percent lower by 2050.

Figure 6.8: Emissions under Sensitivity C – Limited Emissions



D — Alternate Fuel Sourcing RNG Not Limited to PNW[14]

This sensitivity removes the constraint on sourcing alternate renewable fuels from the PNW to include North America; this applies to RNG.

Baseline Assumption: RNG is limited to a supply curve representing the availability and prices within the PNW.

Sensitivity: In this sensitivity, the portfolio allows the purchase of RNG outside of PNW from all regions within North America.

Portfolio results:

[14] We only have considered green hydrogen within the PNW, so this sensitivity is limited to RNG.

- The portfolio selects 12,000 MDth per year or 38 Mdth per day of RNG attributes sourced from outside the PNW starting in 2040.
- This results in a savings in NPV of $93 Million in 2024 dollars over the reference scenario, where RNG is restricted to regional sourcing.

E — Hybrid Heat Pump (HHP) Adoption Policy

This sensitivity models a policy where the hybrid heat pump is the preferred technology to electrify existing gas space heating loads at the end of the equipment life of PSE residential customers. The other end uses in residential and non-residential sectors are also assumed to be electrified.

Baseline Assumption: The portfolio model chooses the cost-effective amount of hybrid heat pump systems as gas conservation measures for residential space heating and electrification for other end uses. This sensitivity uses the conservation supply curve from the reference scenario. We offered the option not to renew pipeline contracts before 2033; all pipeline contracts were assumed to renew after 2033.

Sensitivity: The portfolio model forces the replacement of residential gas furnaces with hybrid heat pump systems and electrification for other end uses. We also electrified the commercial and industrial sectors where feasible (see the Gas DSR report in Appendix E: Existing Resources and Alternatives for more details). The reference scenario's conservation supply curve is modified to reflect the diminishing gas loads. We extended pipeline renewals for all contracted capacity beyond 2033 to allow the portfolio model to optimize it around a gas demand that will decline significantly due to the HHP policy.

Portfolio results:

- Cost-effective conservation is lower because: (1) The conservation supply curve based on the HHP adoption policy has lower potential savings than in the reference scenario due to declining demand, and (2) the cost-effective result occurs at a lower cost point on the supply curve than in the reference scenario.
- Pipeline renewals are lower in the years after 2033 than the reference scenario,[15] as more end uses are electrified, and peak gas loads decline from the electrification of the non-hybrid heat pumps. However, significant pipeline capacity is maintained in the electrification scenario to provide gas on peak days to serve the hybrid heat pump systems designed to run on gas when the outdoor temperature drops below 35F.[16] Figure 6.9 shows the resource builds.

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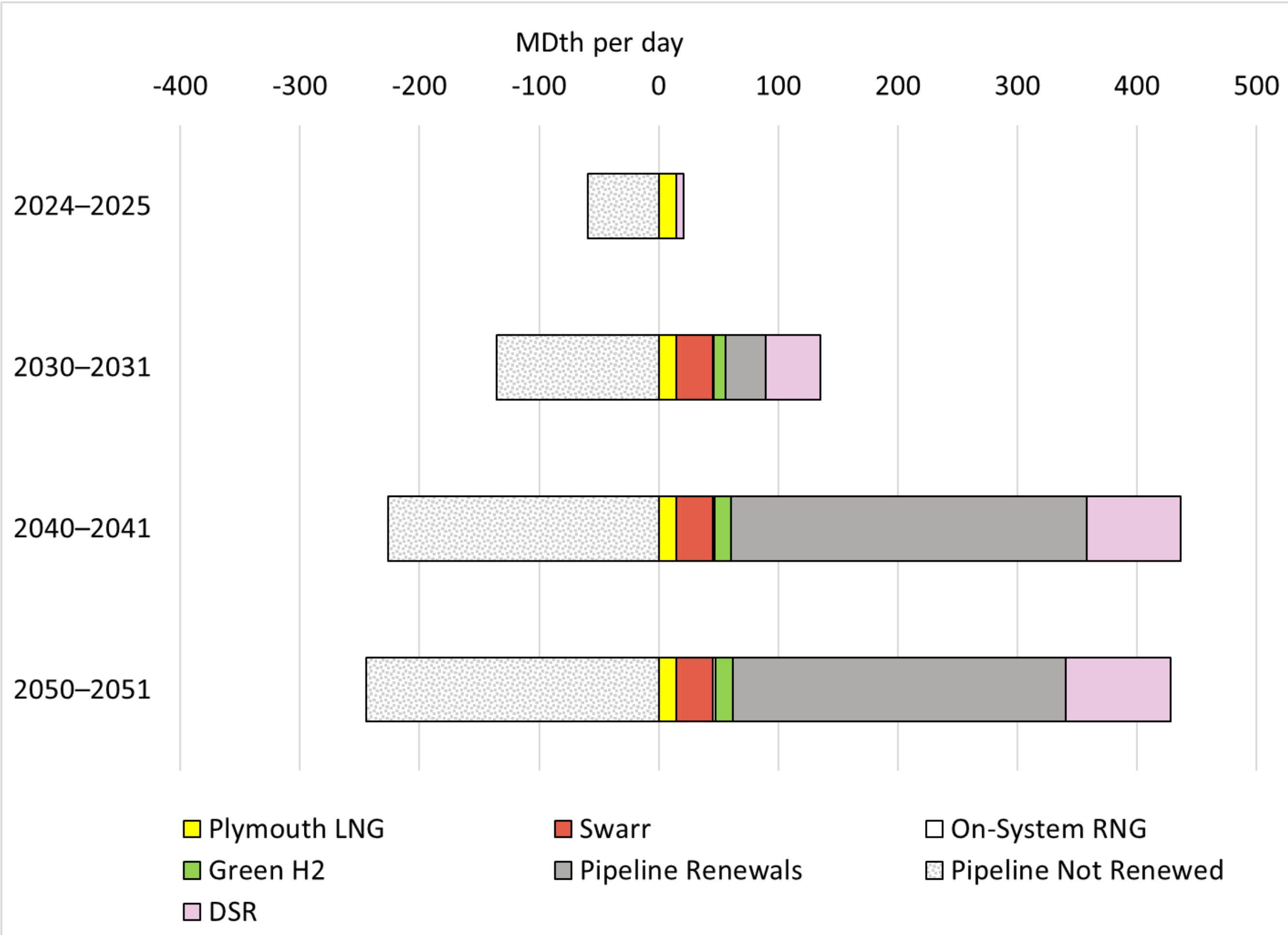
[15] In the reference scenario, we assumed all existing pipeline capacity beyond 2033 will be renewed and so it does not show up as renewal pipeline capacity on the resource build chart, but it is more that is being renewed under the HHP Policy sensitivity.

[16] The assumption for the switchover temperature is 35F, there are some heat pumps that can operate down to 30F, however since the electric system normal design peak is 28F this switchover temperature is not relevant if it is at 30 or 35F the electric system will not experience the peak load from the hybrid heat pump.

Figure 6.9: Resource Builds for HHP Policy Sensitivity



F — Zero Gas Growth

This sensitivity looks at the impact of zero-gas customer growth.

Baseline Assumption: We assumed the 2023 Gas Utility IRP demand forecast, also known as the Mid demand forecast.

Sensitivity: Used a demand growth forecast based on zero gas customer growth.

Portfolio results:

- The lower demand results in more pipeline capacity not being renewed.
- The resource additions are the same as in the reference scenario, except for the pipeline renewals and conservation. More pipeline capacity is not renewed, and lower conservation results are mainly due to the lower achievable technical potential in the supply curve, even though the conservation cost point on the supply curve is essentially the same as the reference scenario.

G — High Gas Prices

This sensitivity looks at the impact of a high gas price forecast on the portfolio.

Baseline Assumption: We assumed Mid natural gas price forecast.

Sensitivity: Use a high natural gas price forecast.

Portfolio results: The resulting portfolio has the identical resource additions as the reference scenario, but the total portfolio costs are higher than the reference scenario.

8.4. Electrification Analysis Results

The electrification analysis consisted of model runs in the gas and electric models. There were two cases in which there was conversion to electric loads, and we analyzed the impacts on both the gas and electric portfolio:[17]

1. Electrification: This is an electrification policy scenario where all residential end uses are converted to electricity, and 70 percent of the end uses in the commercial sector and 30 percent in the industrial sector are assumed to be feasible to convert to electricity.[18] We treated the end-use conversions as a must-take or policy case where mandates dictate that the gas equipment must be changed to electric at the end of its useful life. We tested this in scenario 2: Electrification — WA State Energy Strategy.[19]

2. Hybrid heat pump (HHP) Policy: This policy case is the same as the electrification policy above, except that it uses hybrid heat pump systems for space heating end use in the residential sector.

Electrification in this context assumes that a policy restricts the replacement or addition of gas equipment to serve end-use loads. Gas end uses eventually become electrified. We assumed that some residual segments in the commercial and industrial sectors are unsuitable for electrification. In the commercial sector, this is approximately 30 percent of the loads; in the industrial sector, it is roughly 70 percent. We developed the end-of-life replacement of gas equipment and assumptions around sector-level electrification as part of the conservation potential assessment (CPA) work. Appendix E: Existing Resources and Alternatives provides more details on this process.

A key feature of this scenario is that we forced electrification into the gas and electric models. The CPA provided forecasts for the load reduction on the gas system and load builds on the electric system. We also updated the energy-efficiency supply curves to reflect the changing load characteristics.

We account for the electric transmission and distribution (T&D) costs associated with the electrification as part of the levelized cost in the gas supply curve associated with electrification (there was no T&D cost for the HHP policy case).

[17] There was an electrification option with a hybrid heat pumps for residential space heating as an economic choice in the reference and the sensitivities (except the HHP Policy sensitivity). None of the sensitivities, except the limited emissions selected the HHP option. The limited emissions sensitivity selected the HHP since physical emissions reduction was prioritized over allowance purchases in this sensitivity. In essence the HHP was forced into the portfolio.

[18] See Appendix C: Conservation Potential Assessment for more details.

[19] The WA State Energy Strategy (https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/) follows a more stringent path to reducing emissions. This assumption was included with the electrification scenario.

The electric system-related costs related to the increased resource additions to serve the added electric energy and peak load were an output of the electric portfolio model. The analysis considered gas savings and non-energy impacts as benefits. We detailed these costs in the CPA and summarized them in Table 6.5.

Table 6.5: Electrification Levelized Costs in the Gas Analysis[20]

Included Costs	Benefits Netted Out
Present Value (PV) of Capital Cost of Equipment Conversion	PV of Natural Gas Avoided
Program Cost (HVAC equipment program admin-adder based on EE potential estimates, all other end-uses based on 21% of equipment conversion cost)	PV of Conservation Credit (10% of conserved natural gas energy)
Added Electric T&D Costs (for non-hybrid systems)	PV of Non-Energy Impacts
Panel Upgrade Cost	N/A

8.4.1. Electrification Scenario — Gas Results

Table 6.6 shows our assumptions in the gas portfolio model followed by a discussion of the run results.

Table 6.6: Electrification Scenario

Scenario #	Scenario Name	CCA Constraint Parameter	CCA Allowance Price	Renewable Fuel Source Location	Renewable Fuel Heating Load Shift	Demand*	Gas Growth?*	Gas Price*
2	Electrification-State Energy Strategy (SES)	Follow SES line	Floor	PNW	Force in Cadmus Electrification Results	Mid (F22)	Yes	Mid

Notes:

* Typical Gas IRP parameters

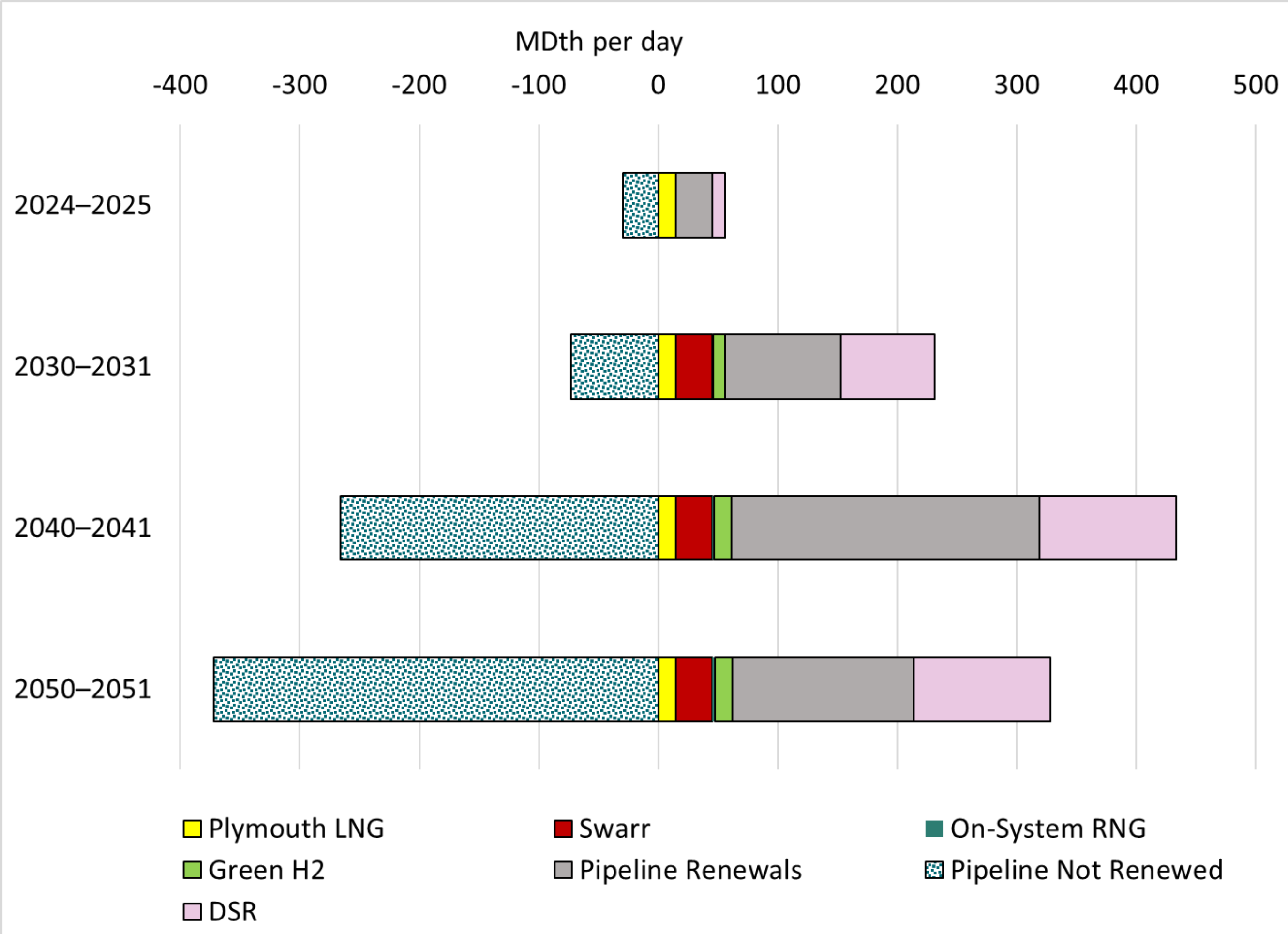
The gas analysis of this scenario assumes a Washington State Energy Strategy (WASES) as the physical emissions limit such that all electrification,[21] conservation, renewable fuels are maximized, and emissions minimized. We made any remaining load and emissions compliant with allowances purchased at a floor price.

We show the resource builds in Figure 6.15. In this scenario, we added pipeline capacity held by PSE beyond 2033 for renewal, and the gas model selected the renewals to rationalize the need. A significant portion of the pipeline capacity is not renewed by 2050. The peaking resources Swarr and Plymouth LNG are chosen in the reference scenario, while all the alternative fuels, RNG and green Hydrogen, are selected in the electrification scenario. Conservation is lower because the supply curve reflected the electrification and had a smaller achievable technical potential.

[20] We did not capture the additional costs to serve the energy and peak needs of the electric loads in the gas analysis, these are outputs of the electric portfolio analysis and discussed in the electric portion of the electrification analysis that follows.

[21] In the electrification scenario, it is not feasible to convert all the end uses in the commercial and industrial sectors. See Appendix E Conservation Potential Assessment for details of the electrification supply curve.

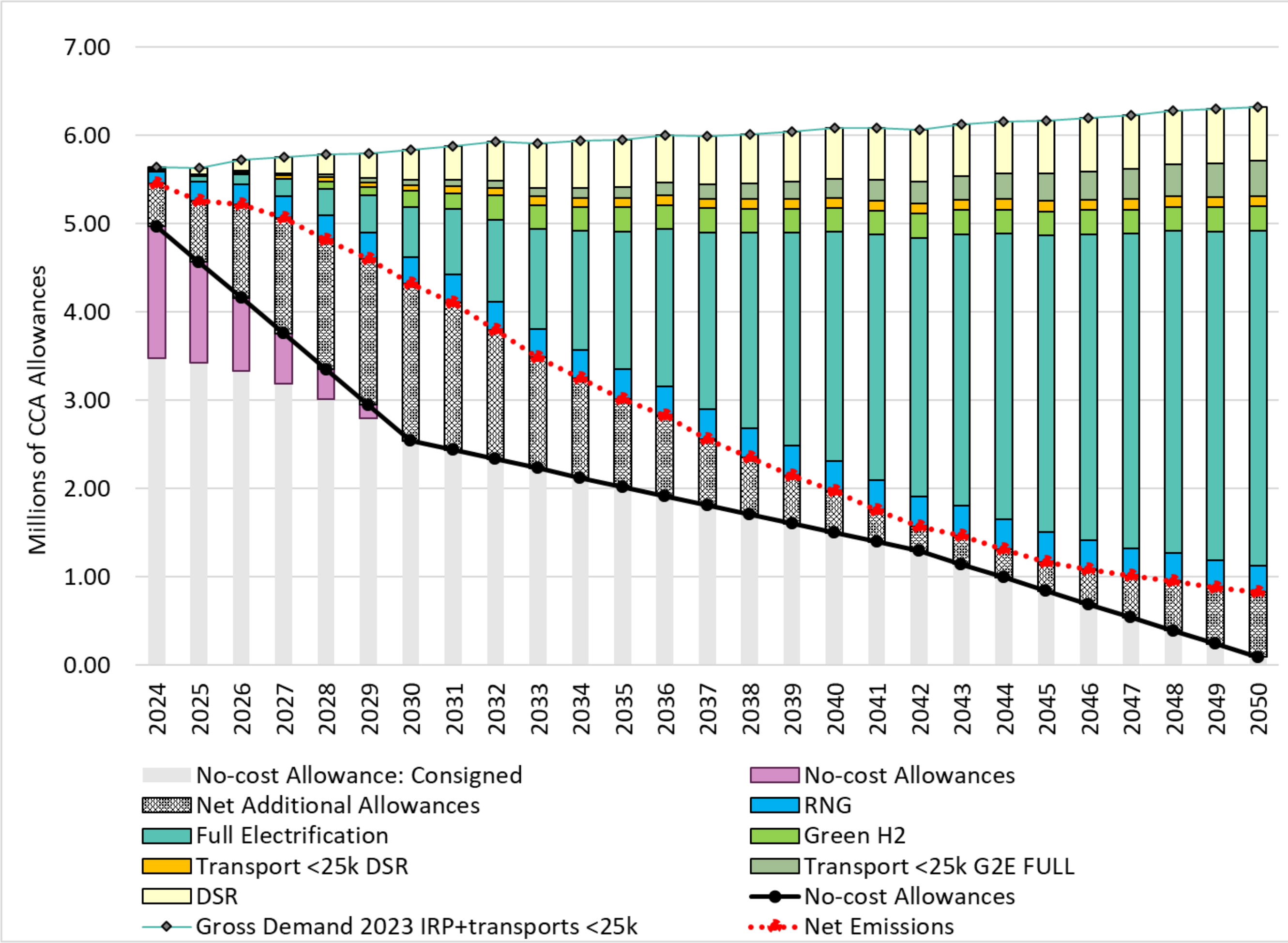
Figure 6.10: Electrification Scenario Portfolio Resource Additions — Peak Day



We show the emissions reductions related to the CCA-no-cost allowances in Figure 6.14. Since the Washington State Energy Strategy (WA SES) pathway is below the CCA no-cost allowance line, the no-cost allowances will cover the emissions between the WA SES and the CCA trajectory. The emissions above the no-cost allowance line and the physical emissions reduction are covered by net additional allowances purchased at the floor price. Electrification is the most significant contributor to emissions reductions, followed by conservation and alternate fuels.

Even with the electrification of the PSE system, the resulting emissions reductions will not be enough to bring emissions at or below the WA SES trajectory, and we will have to supplement them with net additional allowance purchases for CCA compliance.

Figure 6.11: Emissions Reduction Electrification Scenario



8.4.2. Electrification Scenario — Electric Results

For this report, PSE conducted two electrification scenarios to examine the impacts on the electric system of customers switching over from gas to electric. The two scenarios include a full electrification scenario where all end uses are electric, including electric heat pumps for residential space heating, and a hybrid heat pump case. This scenario is the same as the electrification, except the model assumed a dual-fuel hybrid heat pump served the residential space. For a complete discussion on assumptions and modeling parameters, see Chapter Four: Key Analytical Assumptions.

The electric portfolio results for electrification are the mirror image of the peak capacity, and load shed on the gas system. Hybrid Heat Pumps have a dual role as part of a decarbonization strategy by reducing gas usage and providing peak capacity backup to the electric system at lower temperatures. There is only a marginal difference in load between the electrification and HHP scenarios; however, the electrification scenario will require an additional 2,400 MW in peak capacity by 2045 compared to the HHP scenario. (See Figure 6.12 below.) The electrification scenario total portfolio cost with the social cost of greenhouse gases is $24.71 billion, and the HPP scenario is $23.43 billion resulting in a difference of $1.28 billion. (See Table 6.7) These results indicate that the HHP strategy will be the more cost-effective for achieving significant decarbonization results.

Table 6.7: Net Present Value of the Portfolio Cost (Billions $)

Cost Item (Billions $)	Reference	Electrification	Hybrid Heat Pump
Portfolio Cost	$17.8	$20.23	$19.98
Social Cost of Greenhouse Gases	$3.31	$3.74	$3.84
Incremental T&D Cost	$0.00	$0.74	$0.18
Total	$21.11	$24.71	$23.43

As mentioned, both electrification cases increase the electric peak need, especially in later years. The electrification scenario requires 7,800 MW of peak capacity by 2045, almost a 3,000 MW increase from the reference portfolio. The HPP scenario requires a more modest 5,400 MW of peak capacity; increasing the peak capacity need only 500 MW from the electric reference portfolio. This result speaks to the effectiveness of the hybrid systems in relieving stress on the electric system during peak hours. Figure 6.12 illustrates the growing winter peak capacity needed over time because of the electrification cases.

Figure 6.12: Electrification Winter Peak Demand Impacts

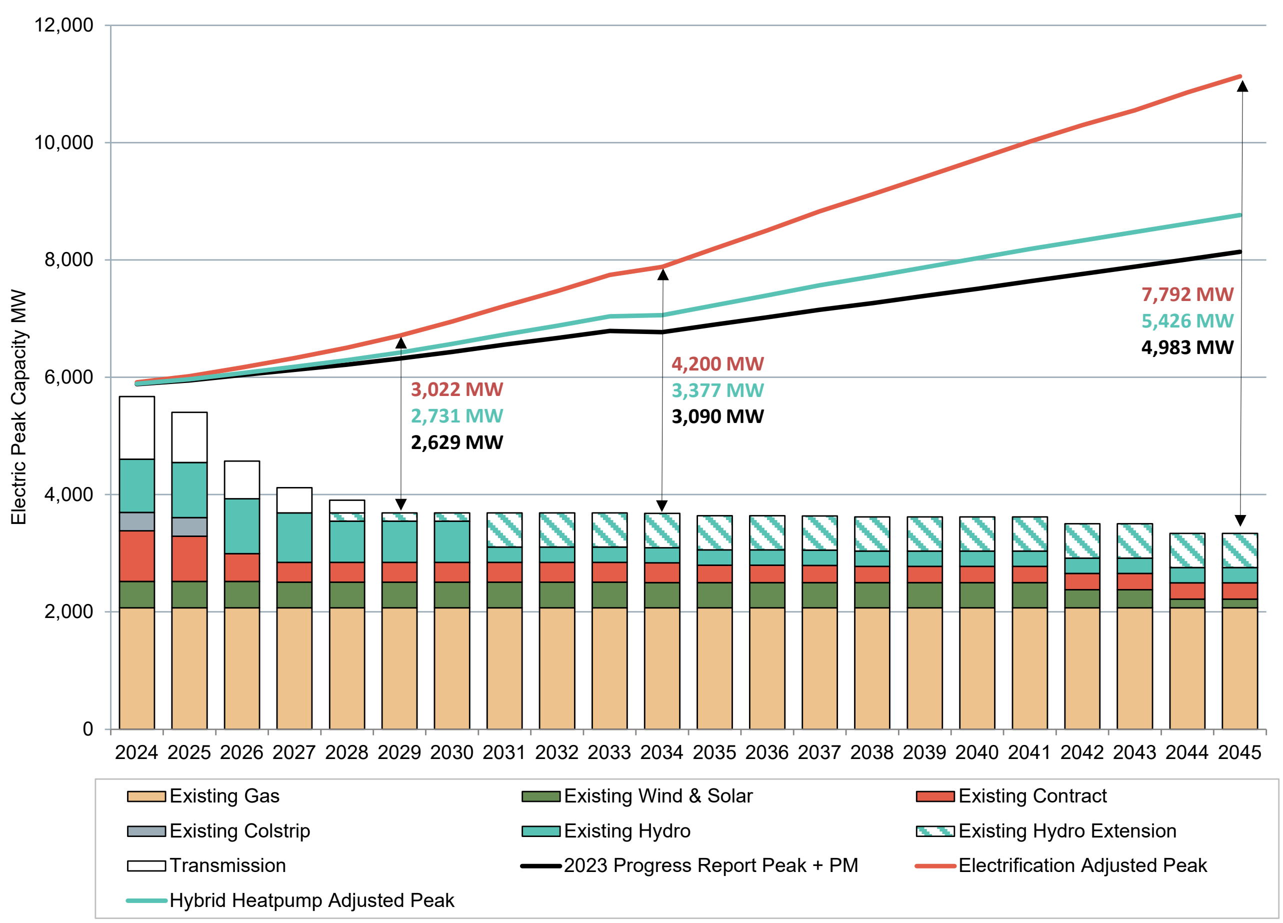
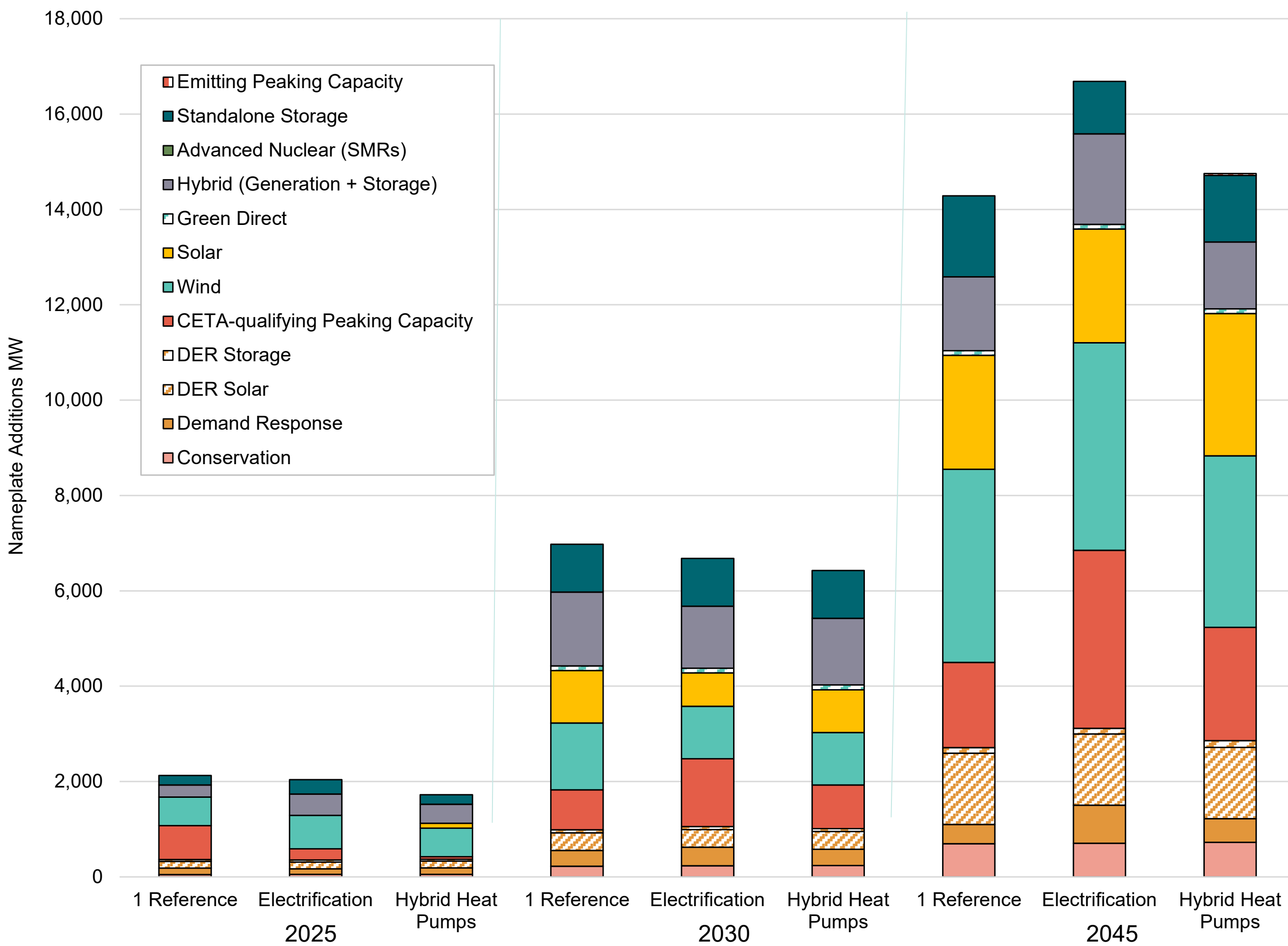


Figure 6.13 details the cumulative capacity added to the portfolios in 2025, 2030, and 2045 to meet the increasing peak need. The full electrification scenario builds almost 2,000 MW more CETA-qualifying peaking capacity by 2045, while

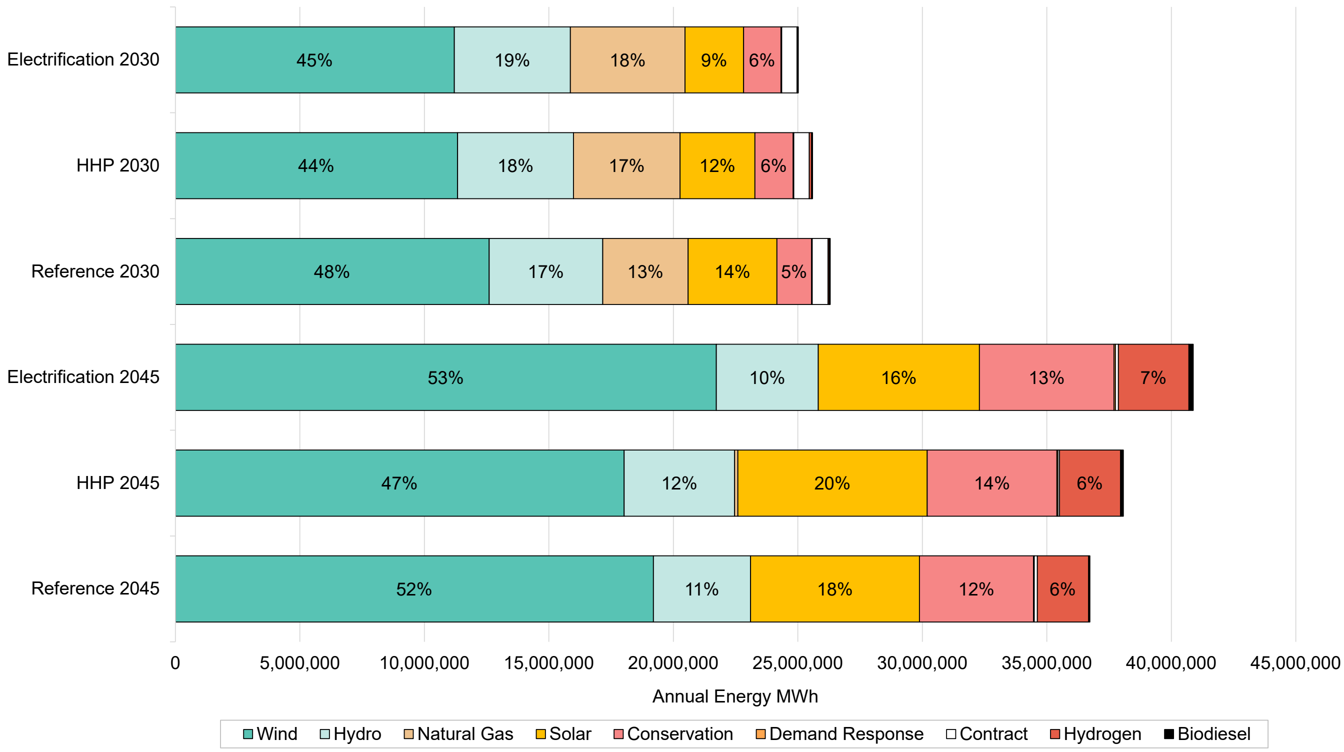
the HHP scenario results in nearly 600 MW more. The electrification and HHP scenarios build 600 and 300 MW less of standalone storage, respectively, slightly more demand response and less conservation by the end of the planning horizon, and both add more capacity overall than the reference case. There is limited resource movement in other categories, and it does not change by more than a couple of hundred megawatts in each direction by 2045.

Figure 6.13: Nameplate Resource Additions



There is minimal difference in load between the electrification scenario and the HHP policy scenario. The electrification scenario projected a 2045 load is 39.2 million MWh, while the HPP scenario projects 38.9 million MWh. For context, the demand for the reference case in 2045 is 32.4 million MWh. A 150 MW wind project could fill the load difference between the electrification and the HHP scenarios. Figure 6.19 details the energy contributions by fuel type in 2030 and 2045 among all three study cases, excluding unspecified market purchases and sales because the fuel source isn't traceable for those resources. The reference portfolio produces more energy in 2030 than both electrification scenarios, which is the opposite of the demand trend. This result is because the reference case is a net energy exporter in 2030, while both the HHP and electrification scenarios are net importers to meet customer demand. Moving to 2045, the energy production of the electrification and HHP scenarios easily surpass the reference case due to capacity added in 2031–2045. Figure 6.14 also reflects the higher renewable and non-emitting energy production required to meet the increased loads for the electrification and HHP scenarios.

Figure 6.14: Annual Energy Production



→ For more detailed data and information on the electrification scenarios, see Appendix F: Gas Methodology and Results.