RESOURCE PLAN
CHAPTER TWO

PUGET SOUND ENERGY

Contents

1. Introduction

Puget Sound Energy (PSE) is committed to a clean energy future. This 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) is the first planning cycle that examines the impact of Washington State's Climate Commitment Act (CCA). In this IRP, we analyzed how a wide range of allowance prices under the CCA and the social cost of greenhouse gas (SCGHG) on direct and indirect emissions would reduce PSE's natural gas emissions. We tested electrification scenarios for this plan, but electrifying gas demand is not cost-effective even at the CCA ceiling price. Our analysis does not include secondary impacts from the CCA, such as emission reduction activities from incremental conservation, electrification, and renewable natural gas and green hydrogen we may undertake because of price increases or other actions resulting from allowance revenue.

As part of integrating equity considerations into resource planning, we included a spatial analysis of vulnerable populations in the conservation potential assessment. We are committed to expanding our understanding and consideration of equity in resource planning in future IRPs.[1]

Puget Sound Energy's (PSE's) preferred portfolio results from robust analyses developed with input from interested parties, and it meets the Washington Administrative Code requirements. To create the preferred portfolio, we examined how several different future conditions, or scenarios, would impact the least-cost set of resource decisions. Feedback from participants in the public input process significantly influenced the conditions we included in the scenario models.

Public feedback also significantly influenced our decision to use the zero-growth sensitivity as the basis for the preferred portfolio. This approach aligns with the recent movement in state building codes and city ordinances passed in 2022 that restrict gas additions.

More information about the preferred plan is in the following sections in this chapter.

2. Preferred Portfolio and Resource Plan

We based the preferred portfolio on the zero-growth sensitivity, which assumes no new gas customer growth as the basis for its demand forecast. The lower demand over time reduces supply-side resources because of the reduced year-round pipeline capacity from not renewing some capacity contracts. The pipeline non-renewals are partly from reduced resource need from lowered demand and partly from displacement by other cost-effective resources alternatives, such as needle peaking resources,[2] conservation, and on-system alternate fuels such as RNG and green hydrogen.

[1] As described in Chapter One: Executive Summary, we will further address equity in the 2025 Gas Utility IRP. Find details of the analysis in Appendix C: Conservation Potential Assessment.

[2] A needle peaking resource has limited availability and serves for short durations of time to support system reliability.

2.1. Resource Plan

As a result of our analyses for this IRP and our preferred portfolio, we developed an action plan divided into near-term and long-term action items. We added several new priorities in this IRP to some of the near-term things we identified in past IRP cycles, such as acquiring cost-effective conservation.

Near-term Priorities (2024–2029):

- Acquire Plymouth Liquid Natural Gas (LNG) capacity rights and the 15 MDth/day deliverability on the Northwest Pipeline
- Continue engagement to develop and deliver on a plan to incorporate meaningful equity considerations in the 2025 Gas Utility IRP
- Continue to acquire cost-effective conservation
- Continue to assess non-pipe alternatives on the gas distribution system
- Determine technical feasibility impacts and other issues of upgrading the Swarr propane-air injection facility
- Explore which expiring pipeline contracts would be feasible to let expire rather than renew
- Follow the rulemaking process for the Inflation Reduction Act
- Participate in green hydrogen development in the Pacific Northwest (PNW)
- Purchase allowances to meet CCA compliance requirements and rule on use of consigned revenues
- Reduce emission profile by exploring Renewable Natural Gas (RNG) within the PNW and outside the region

Long-term Priorities (2030–2050):

- Explore clean technology and fuel such as direct air capture, green hydrogen, and RNG
- Reduce transport pipeline capacity contracts when the gas sales portfolio becomes surplus from decreasing loads

2.2. Preferred Portfolio Summary

To create the preferred portfolio, we first performed a gas analysis which determined a reference portfolio that provided a least-cost baseline. We then ran additional scenarios and sensitivities that provided a picture of the portfolio under varying conditions. The portfolio runs focused on fuel costs, carbon costs, and demand changes. We based the preferred portfolio on a combination of the results and information gleaned from the different scenarios and sensitivities, not on one scenario. Our work was a subjective exercise attempting to thread a needle through the policy and economic landscapes to develop a portfolio that best meets the policy objectives while minimizing portfolio cost and risk.

We based the preferred portfolio on the zero-growth sensitivity. That sensitivity assumed no customer growth and mid-gas and mid-CCA allowance prices.[3] Table 2.1,[4] a summary of the preferred portfolio, shows net negative supply-side resources. The portfolio does not require us to renew some firm pipeline contracts because of lower demand after conservation and lower-cost new peaking resources. Additionally, renewable fuels delivered on the PSE system do not require pipeline capacity, so we do not have to renew pipeline contracts to meet winter peaks. This diversified resource mix of PSE-owned resources helps maintain a flexible gas portfolio while ensuring enough resources to meet customer needs regardless of changes in customer demand.

Table 2.1: Preferred Portfolio Resource Additions by Type and Time (Capacity in MDth/day)

Resource (MDth/d)	2024	2030	2040	2050
Energy Efficiency	7	61	127	172
Swarr Propane Plant	0	30	30	30
Plymouth LNG	15	15	15	15
Pipeline Renewals	(59)	(142)	(195)	(195)
RNG PNW Regional	0	0	0	0
RNG On-system	0	1	2	2
Green H2 /Gas Blending	0	9	14	14
Net Supply Resources	**(44)**	**(87)**	**(134)**	**(134)**

2.2.1. Energy Efficiency

We based the energy efficiency supply curve in the preferred portfolio on the zero-demand forecast; thus, it has a slightly lower achievable technical potential than in the reference portfolio. The lower demand in the preferred portfolio lowers the cost point on the supply curve, up to which conservation is cost-effective. The overall result is slightly lower cost-effective conservation than in the reference portfolio and a slightly lower cost bundle on the supply curve.

Figure 2.1 shows the preferred portfolio's peak day contribution from cost-effective programmatic conservation and codes and standards.

[3] Mid CCA Price is a blend of the Washington Department of Ecology's (Ecology) expected allowance price in the near-term and the California Energy Commission's (CEC) long-term expected price.

[4] Since most of the regional RNG is received at the gas hubs and displaces natural gas only, it does not show up in the resource builds in Figure 2.1 and Table 2.1. We show only the on-system RNG that displaced transport pipeline resources.

Figure 2.1: Preferred Portfolio Cost-effective Peak Day Savings — Program and Codes and Standards

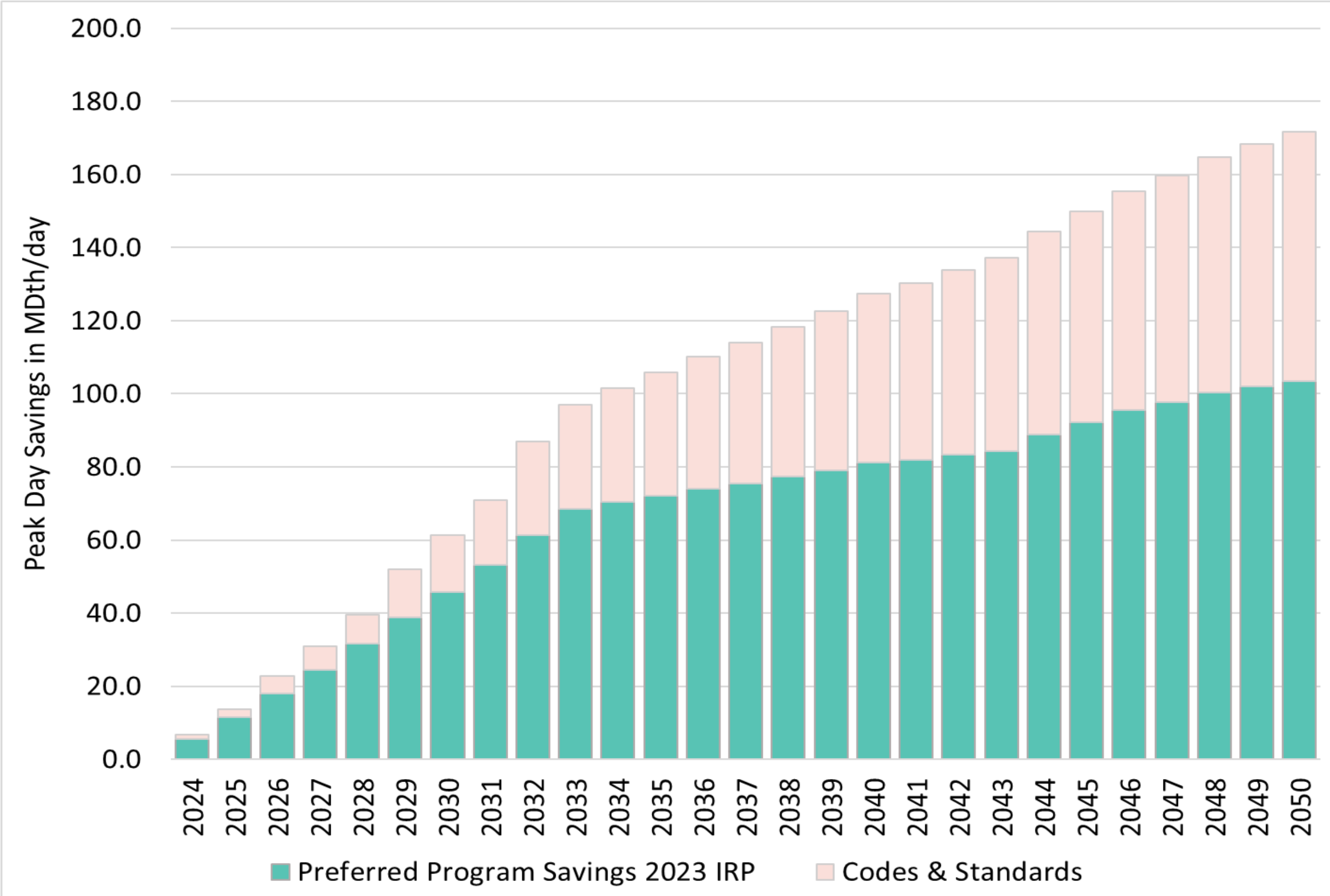


Figure 2.2 compares the cost-effective programmatic conservation to the reference portfolio. We see peak-day savings declines after 2033, beyond which there is no contribution from new gas customers and retrofit measures based on the zero-gas growth assumption in the preferred portfolio.

Figure 2.2: Cost Effective Peak Day Program Savings – Preferred vs. Reference Portfolio

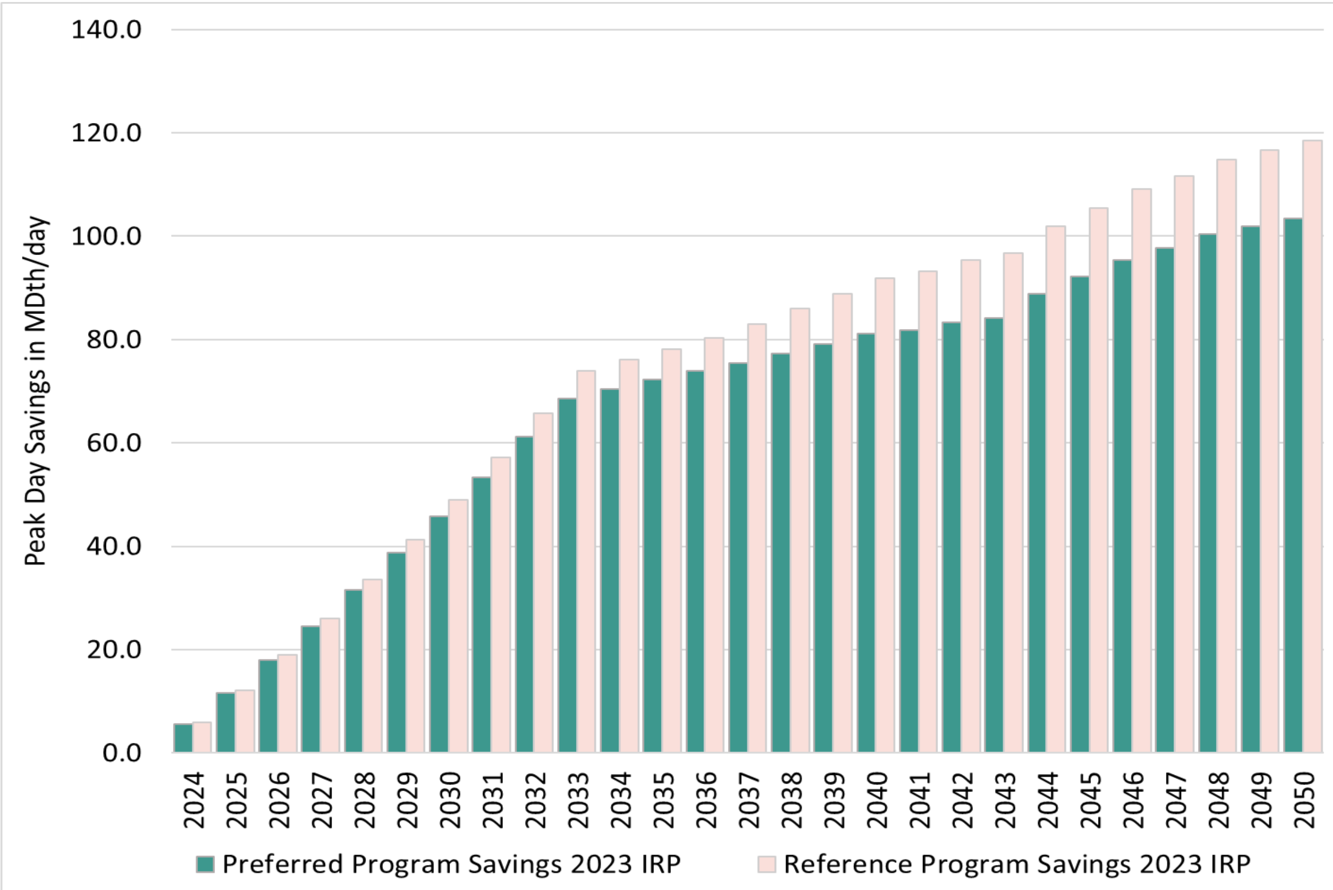


Figure 2.3 shows the energy savings per year for the cost-effective utility program bundles in the preferred portfolio, including the codes and standards savings.

Figure 2.3: Preferred Portfolio Cost Effective Annual Saving — Programs vs. Codes and Standards

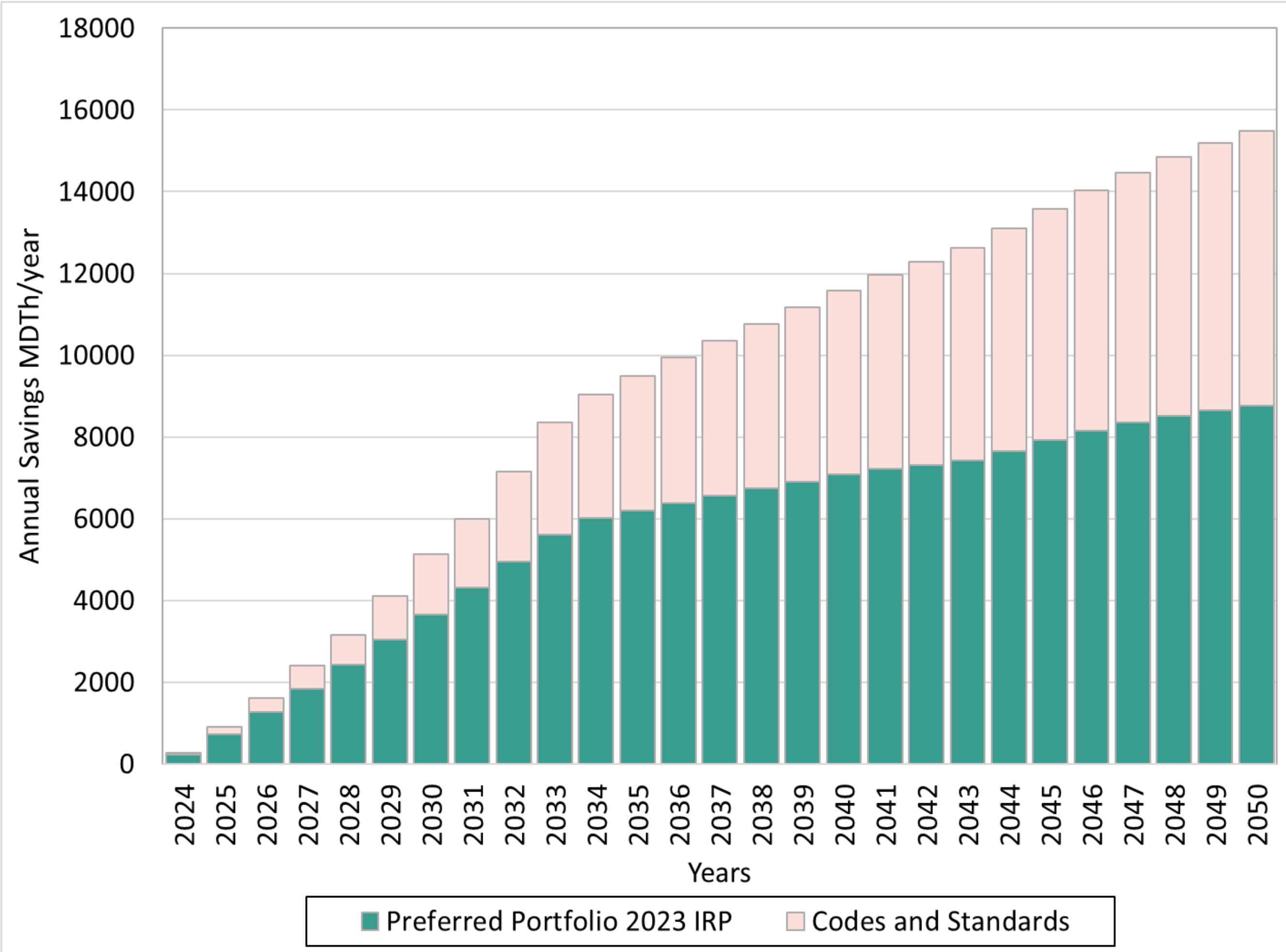
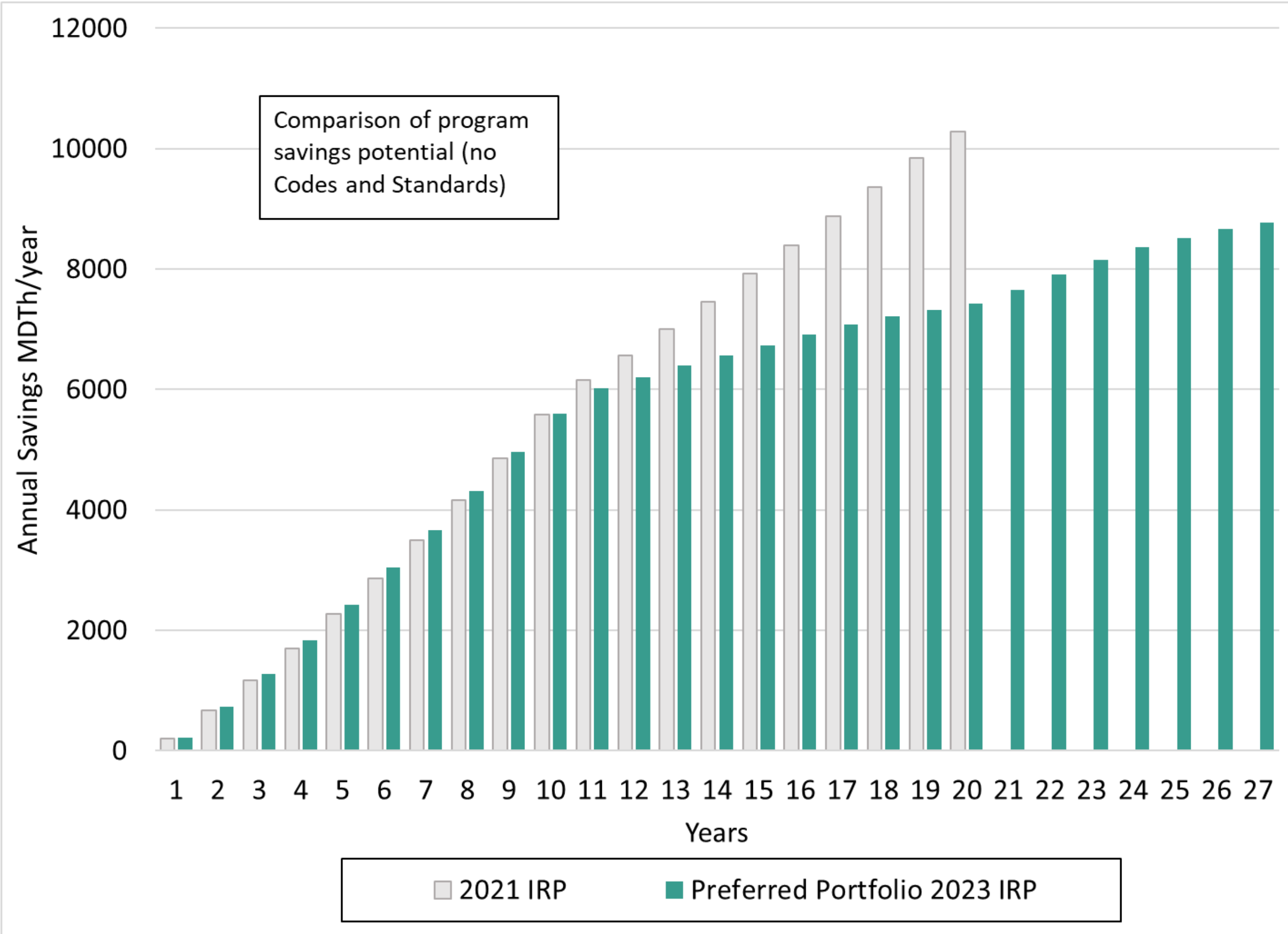


Figure 2.4 compares the cost-effective program annual energy savings in the preferred portfolio against the savings from 2021 Gas Utility IRP. The savings diverge after 2033 because we based the 2023 Gas Utility IRP preferred portfolio on a zero-growth demand and the lack of energy efficiency savings associated with new construction.

Figure 2.4: Cost-effective Energy Efficiency Annual Savings — 2023 Gas Utility IRP versus 2021 Gas Utility IRP



2.2.2. Swarr

The Swarr vaporized propane-air (LP-Air) facility provides firm natural gas supplies on short notice for relatively short periods. Generally a last resort due to their relatively higher variable costs, these resources help meet extreme peak demand during the coldest hours or days. Swarr is a needle-peaking resource that will ensure reliability on cold days, unlike a pipeline resource available year-round.

The Swarr facility is currently out of service pending upgrades to reliability, safety, and compliance systems. An upgrade would have a maximum output of 30 MDth a day available for four days of continuous capacity to the PSE system.

A critical element that makes this resource cost-effective is that it is not a new build; however there may be some additional costs associated with the operations that are not fully reflected in this IRP, they will require some additional assessments that are planned as part of the short-term action plan. This facility will not be operating until 2028. This relatively long lead time will allow us to comprehensively assess the facility, including any impacts or equity-related concerns.

2.2.3. Plymouth LNG

This option includes 70.5 MDth per day firm the Plymouth LNG service and 15 MDth per day firm NWP pipeline capacity from the Plymouth LNG plant. Puget Sound Energy's electric power generation portfolio currently holds this resource, and it may be available for renewal for periods beyond April 2023. Although this is a valuable resource for the power generation portfolio, it may be a better fit for the gas sales portfolio.

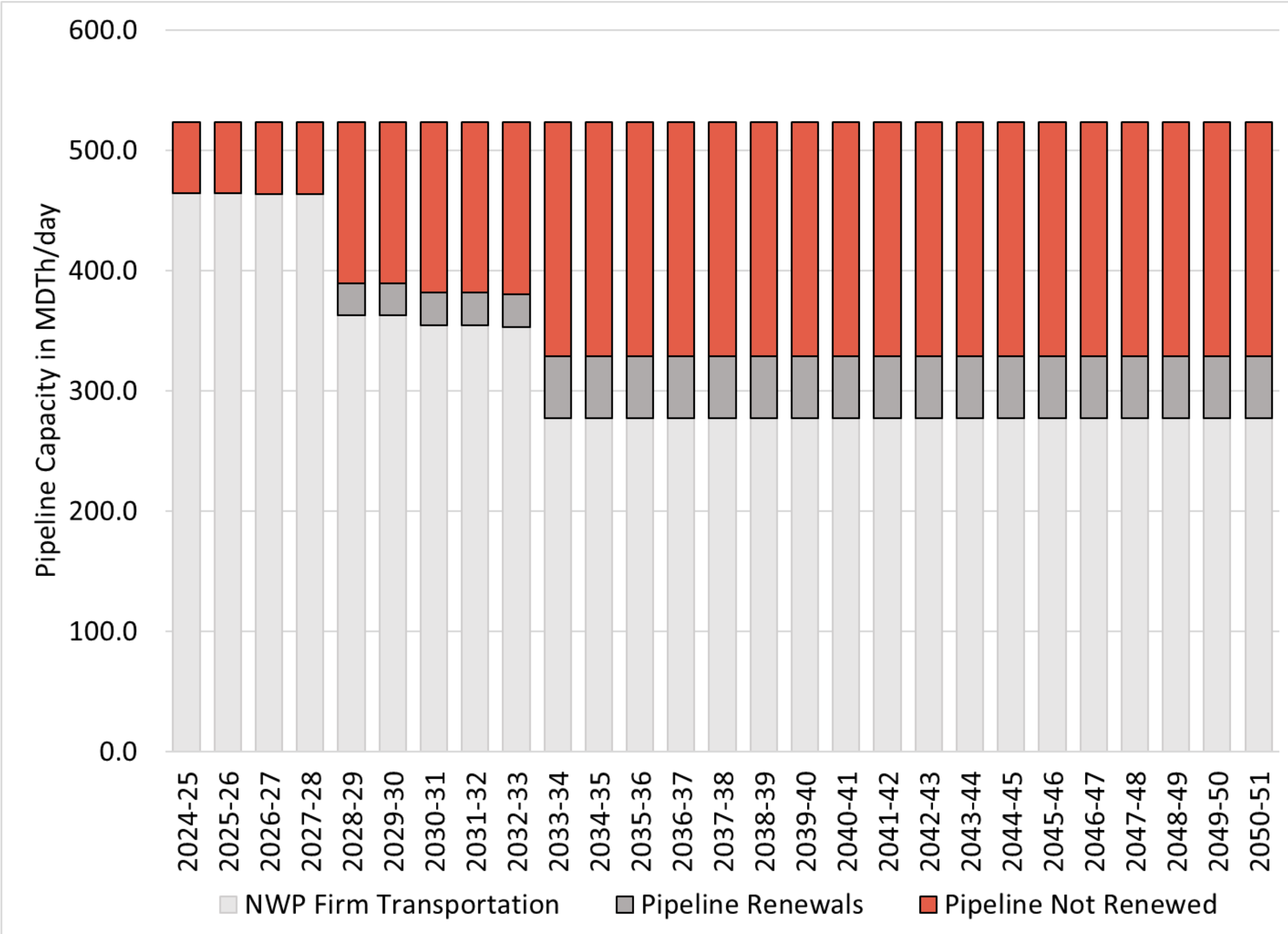
As in the case of Swarr, the Plymouth LNG facility provides short-term availability, mainly for peak and system reliability use; it can provide 15 MDth a day for slightly over four days.

2.2.4. Non-renewed Transmission Pipeline Capacity

In a departure from prior IRPs, where we assumed existing pipeline capacity would be renewed annually, in this analysis, the annual renewal was a resource alternative so renewals could compete with other supply and demand-side resources. We bundled multiple pipeline contracts to specific periods on segments from Sumas in the north and south, connecting via the Gas Transmission Northwest (GTN) to the Alberta Energy Company's (AECO) hub and the Rockies, and added them to the models for optional renewal.[5]

[5] The actual unwinding of some of the pipeline contracts vary in capacity and timing than the simplified approach in the gas modeling shows. There are requirements in the covenants to balance capacity between the north and south segments of the pipelines that we did not consider in this study. This study focused on transmission pipeline connecting to the PSE load or system. Capacity not renewed will also have implications for renewals on the upstream segments. Pipeline demand charges for the remaining pipeline will likely be realigned with the new capacity and will likely increase, these impacts were not included in the 2023 Gas Utility IRP.

Figure 2.5: Transmission Pipeline Capacity Not Renewed in the Preferred Portfolio



2.2.5. Renewable Natural Gas (RNG)

We categorized RNG by geographical location,[6] system location, and characteristic of the RNG (commodity plus attribute[7] or attribute only) as follows:

1. **RNG PNW Region**, with commodities and attributes delivered at the gas hubs. This RNG would displace natural gas and therefore had no increment to the pipeline capacity required to deliver the RNG to the PSE system.

2. **On-System RNG,** with commodity and attributes delivered on the PSE system. Since this RNG is delivered on the distribution system, it displaces an equivalent amount of transmission pipeline capacity.

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[6] The default geographical location was PNW as stipulated in the CCA rules. We tested the North American sourcing in a sensitivity. See Chapter Four: Key Analytical Assumptions for more details.

[7] RNG is composed of the commodity and environmental attributes, which are the value associated with the environmental benefits inherent in RNG. These attributes are often sold separately and can be purchased to clean up conventional natural gas.

3. **RNG Attributes,** only the environmental attributes, sourced from the PNW, are purchased and with associated gas delivery from the Stanfield hub. We paired this resource with gas from the hub so it does not reduce or increase transmission pipeline capacity needs.

The reference scenario and the preferred portfolio's default sourcing geography was limited to the Pacific Northwest (PNW).

Table 2.2 shows the cost-effective RNG in the preferred portfolio. We included the existing RNG for informational purposes only; it was not part of the resource alternatives tested in the 2023 Gas Utility IRP.

Table 2.2: Cost-effective RNG in the Preferred Portfolio

Preferred Portfolio 2023 IRP	2030 Annual Energy (MDth/year)	2050 Annual Energy (MDth/year)	2030 Peak Day Capacity (MDth/day)	2050 Peak Day Capacity (MDth/day)
RNG PNW Region	0	0	0	0
On-system RNG	400	900	1.1	5.3
RNG Attributes	0	0	0	0
Existing RNG	1,940	1,180	2.5	3.2

2.2.6. Green Hydrogen

Green hydrogen is created through an electrolytic reaction using renewable power to split fresh water into its constituent hydrogen and oxygen atoms. The hydrogen is captured, pressurized, and transported to end users via truck, pipeline, or rail. The oxygen is captured for industrial resale or safely vented into the atmosphere. Green hydrogen holds significant promise as an energy source and carrier, giving multiple industries a new solution to help decarbonize.

We are working with partners to develop green hydrogen in the region and anticipate it will be available starting in 2028. Regional green hydrogen capacity will expand as production gears up post-2028. The IRP assumed a third of the final 15 percent by volume[8] blend into the natural gas system will become available in 2028, another third in 2030, and the last third in 2032. All this would be within the eligibility period of the Inflation Reduction Act (IRA) incentives, which were built into the costs for green hydrogen (see Appendix E: Existing Resources and Alternatives). We assumed the green hydrogen would be delivered on PSE's distribution network, so no pipeline transmission capacity is needed or can be displaced.

8 Fifteen percent by volume is well within the range most agree is viable without adverse impacts on end use appliances (see Northwest Energy Efficiency Alliance (NEEA) | Hydrogen-Ready page iv: "*In general, the compilation of different studies indicates that there are limited performance impacts on existing appliances up to 20% hydrogen, and recent evidence suggests the value could be higher.*") Report can be found: https://neea.org/resources/hydrogen-ready-appliances-assessment-report. Fifteen percent by volume corresponds to an approximate 5 percent by energy. The green hydrogen was included in the portfolio models on an energy basis.

After considering the IRA incentives, we found green hydrogen was a cost-effective resource in all the scenarios and sensitivities.

Table 2.3: Cost-effective Green Hydrogen in Preferred Portfolio

Preferred Portfolio	Green Hydrogen (MDth/year)	Green Hydrogen (MDth/day)
2024–2025	0	0
2030–2031	3,460	9.48
2045–2046	5,190	14.22
2050–2051	5,190	14.22

3. Rationale for the Preferred Portfolio

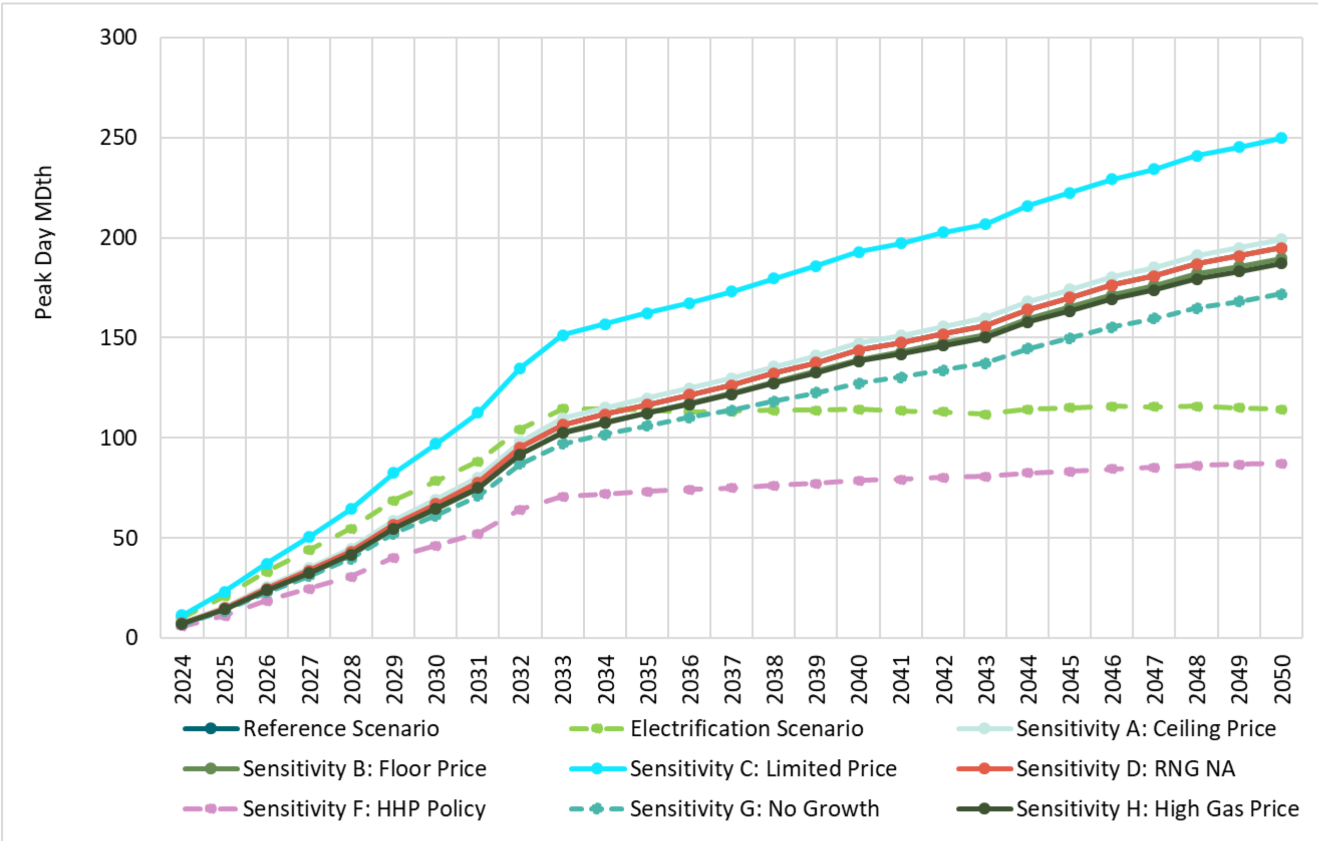
The least-cost portfolio from the zero-growth sensitivity guided us to the final preferred portfolio. The feedback we received from several parties influenced the decision to use the zero-growth sensitivity on our draft resource plan. We all agreed that the zero-growth sensitivity is more reasonable than a forecast that did not include the latest building code revisions. While codes and standards do not eliminate all growth from a risk perspective, the zero-growth assumption is closer to what we expect in the future than the base demand forecast. While the least cost plan from the Zero Growth sensitivity drove this preferred portfolio, we examined all the portfolio analyses to inform our decision. The following goes through each portfolio decision to explain why each element is reasonable.

➔ Please see Chapter Six: Gas Analysis and Appendix F: Gas Analysis Results for detailed modeling results.

3.1. Conservation Demand-side Resources

We based the conservation supply curve for the preferred portfolio on zero-demand growth; it had no conservation related to new construction. This conservation assumption is consistent with zero-demand growth; a demand-growth-based conservation supply curve would not be appropriate as it would create inconsistent modeling inputs by overstating the conservation available when the demand is expected to lower. Figure 2.6 shows the cost-effective conservation by scenarios and sensitivities. The preferred portfolio is the lowest of the non-electrification scenarios, as opposed to electrification, where the gas demand reduction from fuel switching diminishes conservation potential.

Figure 2.6: Cost-effective Conservation by Scenario and Sensitivity



Cost-effective energy efficiency moved in direct proportion to natural gas prices, demand growth, and electrification. Table 2.4 is a tabular representation of Figure 2.6.

Table 2.4: Conservation Savings Range at Peak by Scenarios and Sensitivities (MDth/day)

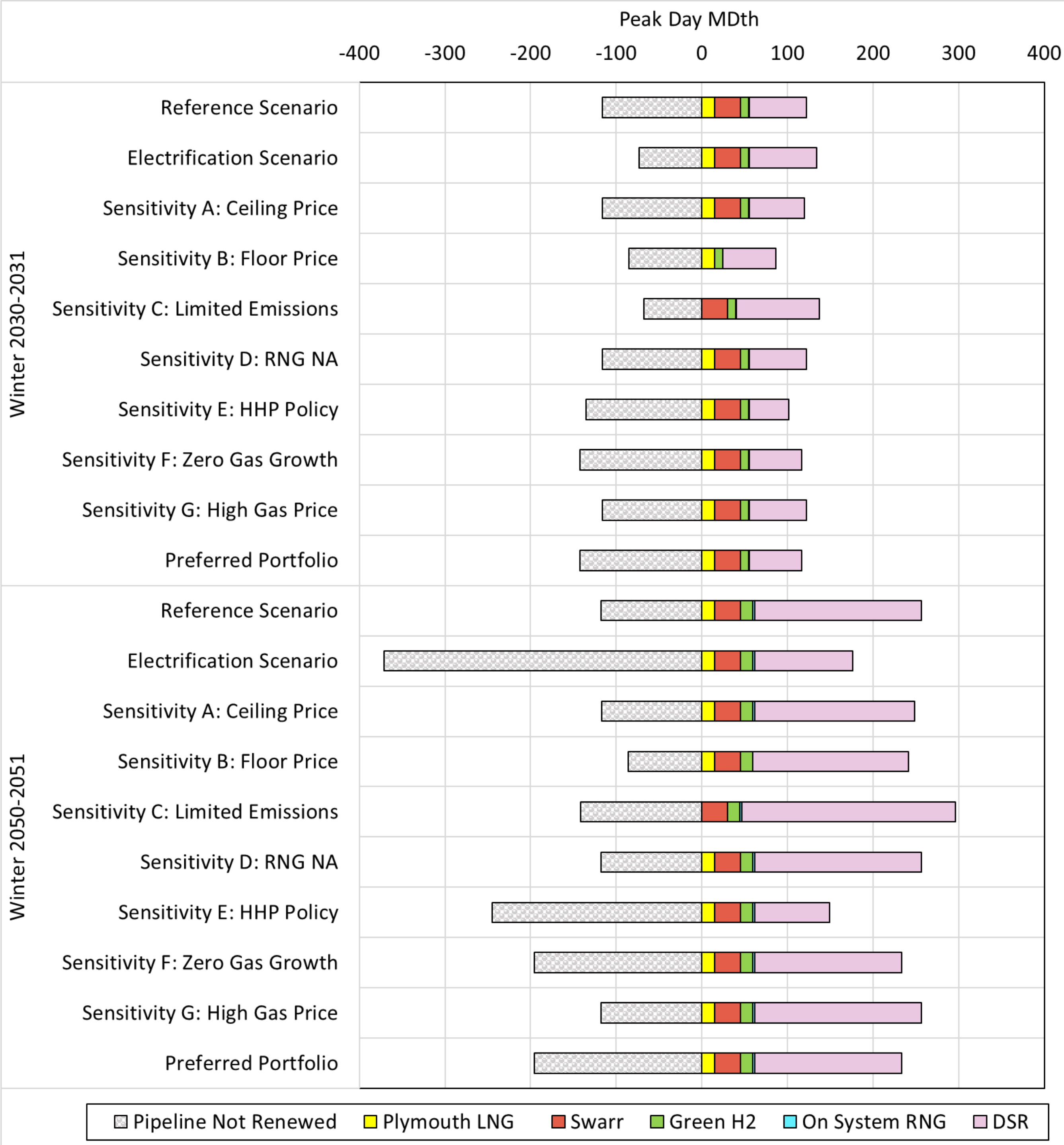
Scenario/Sensitivity	2024	2030	2040	2050
Reference Scenario	7	67	144	195
Electrification Scenario	10	78	114	114
Sensitivity A: Ceiling Price	7	64	138	187
Sensitivity B: Floor Price	7	62	134	182
Sensitivity C: Limited Price	11	97	193	250
Sensitivity D: RNG NA	7	67	144	195
Sensitivity E: Hybrid Heat Pumps (HHP) Policy	6	46	79	87
Sensitivity F: Zero Growth	7	61	127	172
Sensitivity G: High Gas Price	7	65	138	187
Preferred Portfolio	7	61	127	172

➔ Details on the load forecast are in Chapter Five: Demand Forecast, and impacts of conservation across the various scenarios and sensitivities in Chapter Six: Gas Analysis.

3.2. Supply-side Resources

Figure 2.7 shows the portfolio additions' results to serve the peak day. The figure includes supply-side resource additions for the winter 2024–2025, 2030–2031, and 2050–2051 periods of the study.

Figure 2.7: Portfolio Additions – Including Supply Side Resources



The supply-side resources — upgrades to the Swarr Propane Plant, renewing the Plymouth Liquid Natural Gas (LNG) peaker contract, and pipeline capacity not renewed — are present in all the scenarios and sensitivity portfolio resource additions.

There are no near-term resource decisions except for Plymouth LNG. The lead time to acquire the Plymouth LNG peaker contract is short, so we must decide whether to add this contract before 2024. We show Swarr in the preferred portfolio as a need in 2030. Pipeline capacity release would begin as soon as 2024. The SENDOUT model simulates a simplified de-contracting approach, so the actual rate of returning these pipeline contracts may vary based on the terms and conditions of each contract (see Appendix E: Existing Resources and Alternative Table E.5)

3.2.1. Swarr Propane Plant

Upgrades to PSE's propane injection facility, Swarr, are the least-cost resource in all scenarios and sensitivities (see Figure 2.10), even in the electrification cases. Driven by the low cost of upgrading the facility instead of keeping year-round pipeline capacity, the simple payback is less than three years. This resource would have made it into any preferred portfolio choice, and we included it here.

3.2.2. Plymouth LNG

The Plymouth LNG peaker contract is the least-cost resource in all scenarios and sensitivities (see Figure 2.10), except the Limited Emissions sensitivity, even in the electrification cases. Like, Swarr, this is a relatively low-cost resource compared to keeping year-round pipeline capacity. This resource is, therefore, a logical choice to include in the preferred portfolio.

3.2.3. Pipeline Capacity

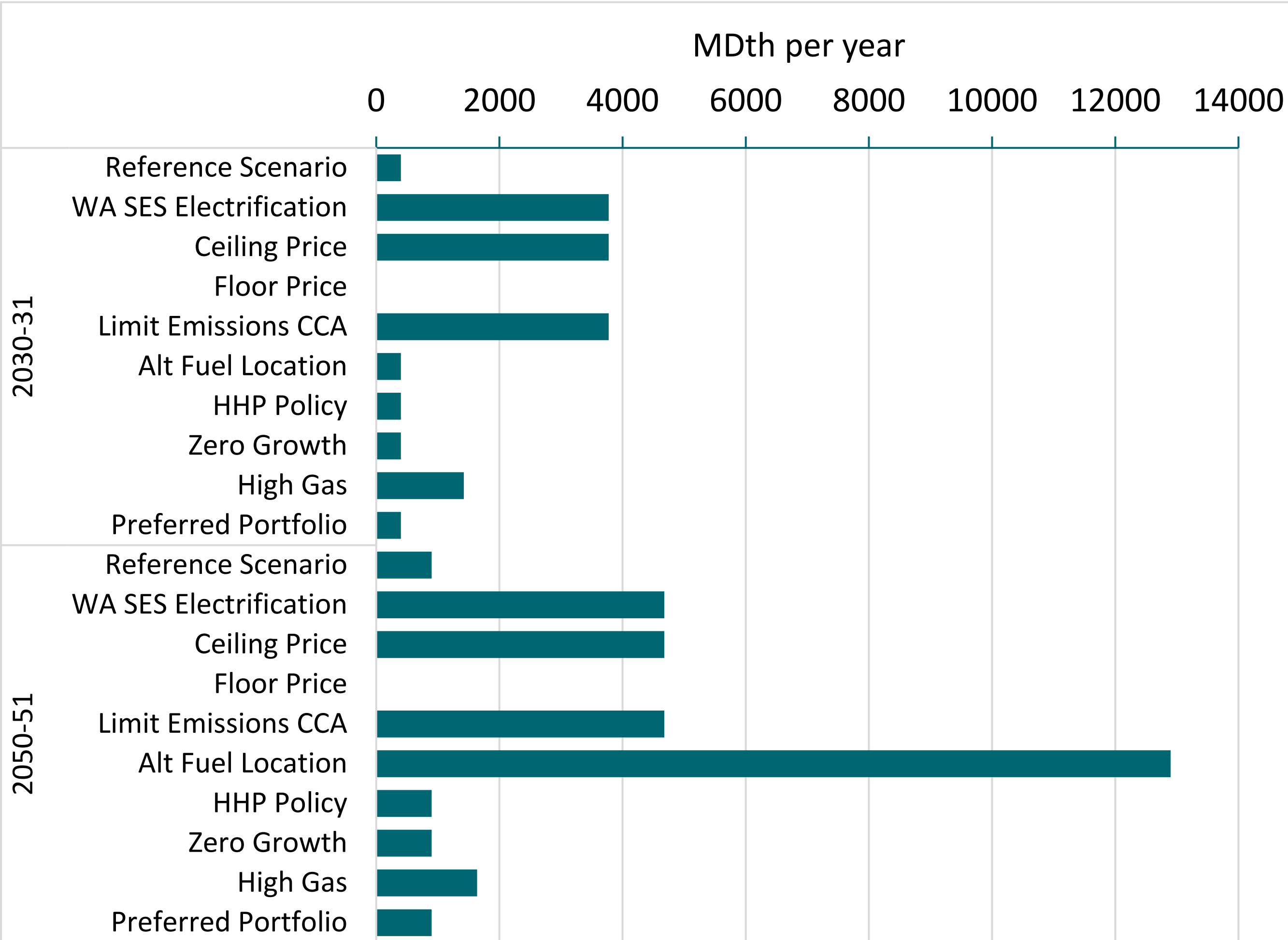
Northwest Power contract renewals are the shock absorber for demand uncertainty. The model shows we must renew fewer pipeline capacity contracts in the scenarios where demand is low (see Figure 2.7). This approach provides a significant amount of flexibility as the future unfolds. Furthermore, many contracts roll over year-to-year, so PSE does not have to make those decisions today.

3.2.4. Renewable Natural Gas (RNG)

Renewable natural gas is mainly price sensitive. As Figure 2.8 shows, more RNG is cost-effective in scenarios and sensitivities where the CCA or gas prices are higher, except for the limited emissions sensitivity, in which the model prioritized all emission-reducing resources before adding CCA allowances for CCA compliance.

The floor price sensitivity is the only sensitivity in which RNG is lower than the preferred portfolio. In most cases, the RNG is either the same or more than in the preferred portfolio. The preferred portfolio at the lower end avoids the risk of overbuilding, and if total gas costs increase, it can add more RNG as needed.

Figure 2.8: Cost effective RNG — Scenarios and Sensitivities by Annual Energy



3.2.5. Green Hydrogen

Green hydrogen is cost-effective in all the scenarios and sensitivities; thus, it would be included in any preferred portfolio. The amount of green hydrogen needed will be lowest in electrification scenarios as demand declines, and the 15 percent blend limit by volume leads to a lower need for green hydrogen. We do not expect green hydrogen to be available for four or five years, allowing time to study the blend quantity and other issues needed to develop this new fuel source.

4. Portfolio Costs

Portfolio costs reflect the new resources' total cost and the portfolio's operating costs, including all CCA allowance costs.[9] The distribution system is not part of the SENDOUT model, so we did not include costs for the distribution

[9] We removed the social cost of greenhouse gases (SCGHG) with the upstream emissions from the portfolio costs shown here.

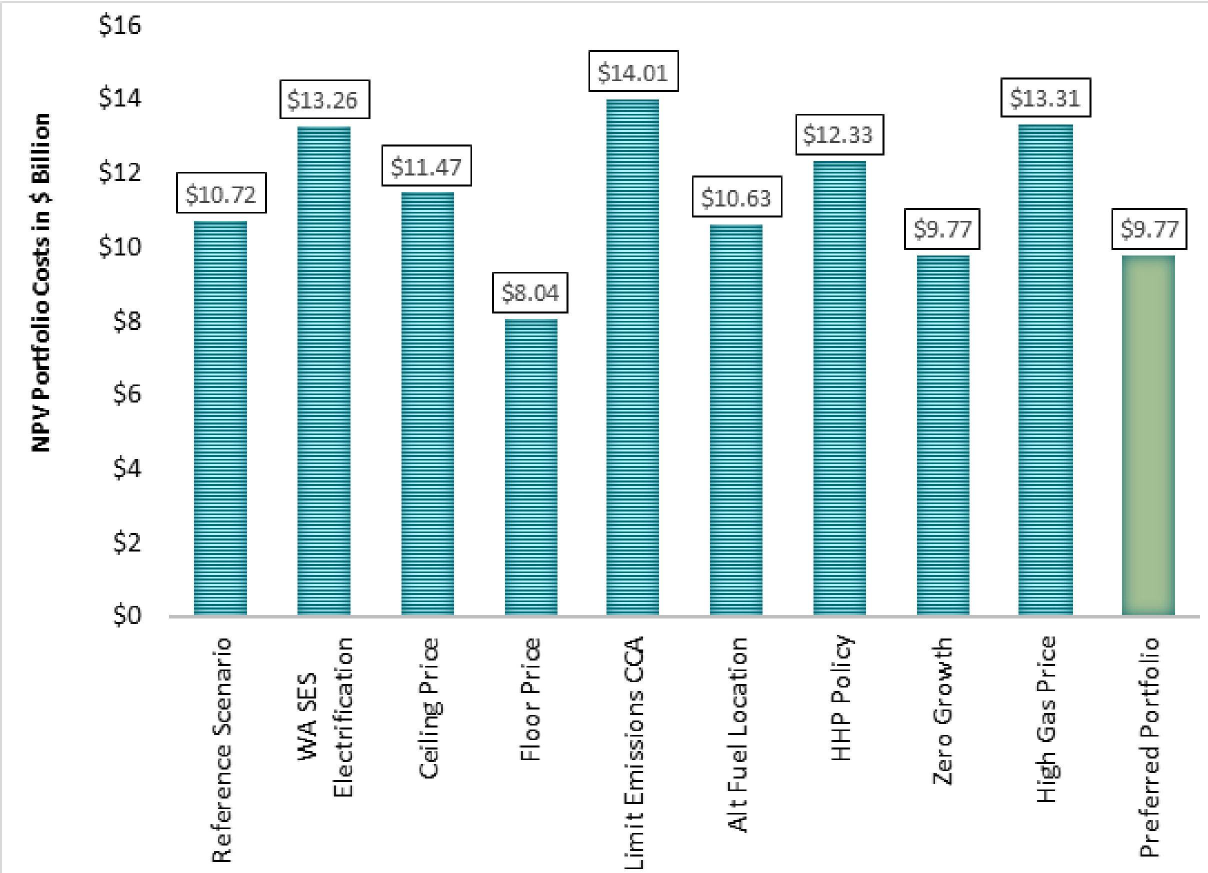
systems. Similarly, we did not include the capital cost of the existing resources such as Jackson Prairie, Gig Harbor LNG, Tacoma LNG, and even portions of the reusable part of Swarr in this cost.

The electrification scenario and the HHP policy electrification sensitivity include costs associated with the electric system's expanded capacity to serve the additional electric demand. The Limited Emissions CCA sensitivity also comprises the market HHP electrification; however, it also has a higher amount of net additional allowances needed to meet CCA requirements, since this electrification sensitivity, unlike the policy cases, only included the hybrid heat pumps as a conservation measure, so it has the highest portfolio cost.[10]

Figure 2.12 shows the portfolio cost in net present value (NPV) and offers the range of costs for all the scenarios and sensitivities. The cost of the preferred portfolio is the second lowest cost and above only the Floor Price sensitivity. The preferred portfolio cost is lower than the Reference Scenario's net present value (NPV) by about $1 billion due to the lower demand.

[10] The WA SES Electrification scenario benefits from the Floor price assumption, a mid-CCA price in this scenario was not run, else it may have been the highest cost of any of the scenarios or sensitivities.

Figure 2.9: Total Portfolio Costs (NPV in 2024$ (Billions))



4.1. Electrification Costs

Electrification costs include measure-related costs and electric system costs. The impact on the gas system cost will consist of a reduction in gas costs offset by costs associated with decommissioning. Decommissioning costs are not included in this study, but could be a consideration in future IRPs. We captured the gas cost reductions in the portfolio costs discussed as a net cost of measure cost and gas reductions.

We developed the measure costs as outputs of the CPA, which are in Appendix C: Conservation Potential Assessment. We developed the equipment cost assumptions from a contractor and builder survey as part of the CPA, and the results are in Appendix C, page A-12. We included measure costs in the gas supply curve inputs to the portfolio analysis; the electric costs are an output of the electric portfolio analysis.

Table 2.5: Electrification Costs by Policy in $ Billions

Electrification Policy	Measure Cost	Electric System Cost	Total Cost
Full electric	5.40	3.37	8.77
Hybrid Heat Pump	3.81	1.44	5.25

These costs do not reflect the cost of any IRA incentives. We need more clarity regarding how we should incorporate these incentives into the total resource cost test used to evaluate conservation measure cost-effectiveness. In this analysis, electrification costs are high, and their corresponding portfolio costs are greater than scenarios and sensitivities that buy net additional CCA allowances.

4.2. Unrestricted RNG Sourcing

In the preferred portfolio, we restricted RNG to the PNW region. If RNG is unrestricted and we could source it from North America, it would provide additional cost-effective emissions reductions in the preferred portfolio. See Figure 2.11 and Table 2.6.

Table 2.6: Emissions Reduction in Metric Tons — Regional RNG vs. Nationally-sourced RNG (Scenario One vs. Sensitivity D)

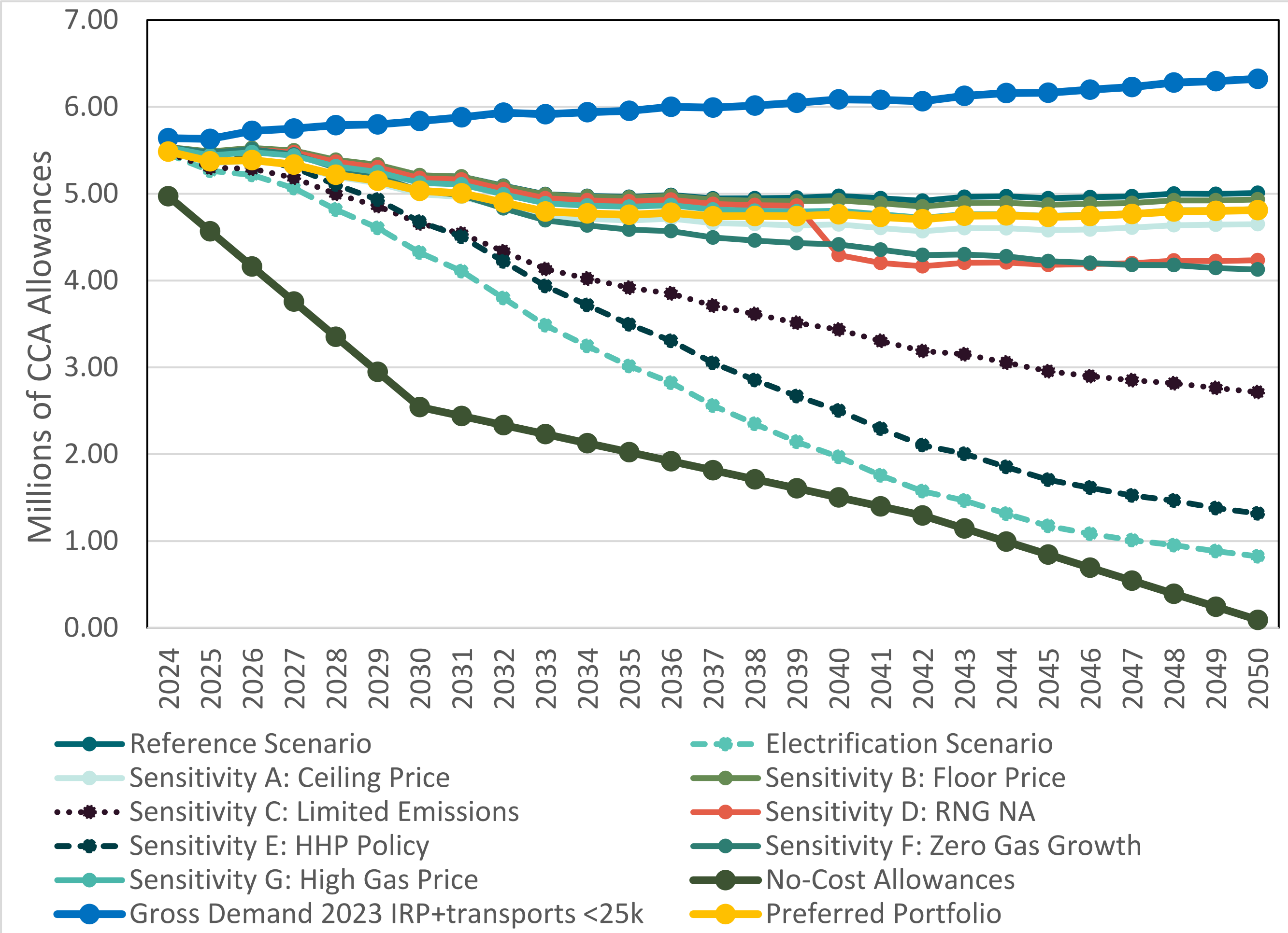
Geographic Footprint	Emissions Reductions 2030	Emissions Reductions 2045
PNW RNG	123,000	120,000
National RNG	123,000	750,000

The nationally sourced RNG in Sensitivity D also has a lower portfolio cost in net present value than the reference scenario by about $93 million in 2024.

5. Emissions Reduction Potential

We included several resource alternatives in the portfolio analysis that would reduce emissions: energy efficiency, hybrid heat pump systems, electrification, regional RNG, and green hydrogen. The gas portfolio model chose from these resources, with the exception of the policy electrification cases where electrification was force into the model, such that the resulting cost of the portfolio is less than the cost without these resources. Figure 2.10 shows the emissions reductions and net additional allowances needed to meet the CCA requirements in each scenario and sensitivity.

Figure 2.10: CCA Allowances by Scenarios and Sensitivities



There are limits to resource alternatives that can yield emissions reductions. Energy efficiency is chosen on the supply curve price point that is still cost-effective.[11] Green hydrogen has a practical upper limit of around 15–20 percent for blending into the gas system by volume without significant infrastructure changes. The two electrification cases, the electrification scenario and the HHP policy sensitivity, represent cases where the model replaced all the gas end-use equipment on burnout. We included no IRA incentive in the scenario costs. The CCA allowance pathways in Figure 2.10 represent a theoretical maximum limit of equipment replacement. Please note that the uptake of electric equipment will not likely achieve a perfect 100 percent replacement. Hence the emissions reductions shown for the electrification cases are theoretical maximums, and the actual reduction will probably be less. How much less will be determined by a combination of market, financial, and policy dynamics.

The preferred portfolio shown in Figure 2.11 results from the least-cost portfolio analysis and the impacts of the most likely policies and other external factors we currently know. The preferred portfolio reduces emissions by 13 percent

[11] See Appendix E: Existing Resources and Alternatives for more details on the cost-effective conservation selected in the preferred portfolio and other gas scenarios.

by 2030 from the emissions baseline at the start of the first compliance period in 2023 and achieves a 27 percent reduction by 2045.

Figure 2.11: Emissions Reduction and Net Additional Allowances Needed in the Preferred Portfolio