2023 GAS UTILITY INTEGRATED RESOURCE PLAN

Appendices A–G

PUGET SOUND ENERGY

2023 GAS UTILITY INTEGRATED RESOURCE PLAN

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PUBLIC PARTICIPATION

APPENDIX A

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1. Introduction

Public participation is an essential part of developing Puget Sound Energy's 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) and meeting regulatory requirements. Puget Sound Energy continues to expand and evolve how we engage with the public, using a structured approach that aims to increase accountability and demonstrate how we incorporate feedback across our work products.

The activities described in this document resulted in valuable feedback, suggestions, and practical information from the organizations and individuals that helped guide the public participation process and informed key components of the 2023 Gas Utility IRP. We thank those who participated in and supported this process for the time and energy they invested, and we encourage their continued participation.

Puget Sound Energy held seven public meetings in 2022 before filing the 2023 Gas Utility IRP with the Washington Utilities and Transportation Commission (Commission) by April 1, 2023.

All materials related to the 2023 public participation process are available at pse.com/irp. The public participation materials include meeting agendas, presentations and datasets, meeting recordings, participant logs, chat transcripts, feedback reports, and meeting summaries.

Puget Sound Energy contracted public participation specialists from Maul Foster & Alongi (MFA) and Triangle Associates to help develop a public engagement strategy, provide independent meeting facilitation, develop meeting and public comment guidelines, assist with meeting documentation, and recommend approaches to promote transparent and timely communication and public engagement.

2. Public Participation Approach

We built public participation for the 2023 Gas Utility IRP on the foundations set and lessons learned through past IRP and other PSE processes. We formally adopted the International Association of Public Participation (IAP2) framework for the 2021 Gas Utility IRP and subsequent 2023 Gas Utility IRP. The IAP2 framework, and various public participation techniques, helped us design and implement an effective public participation process that allowed interested parties to clearly understand how they could influence components of key inputs, assumptions, and decisions throughout the process and provide valuable feedback to PSE.

All meetings were open to the public as we developed this IRP, and we encouraged attendees to participate actively. We observed safety measures for COVID-19 and held all public engagement virtually, using various online platforms, including PSE's IRP website, Zoom, and online feedback forms.

We are committed to reducing barriers to participation, communicating, and engaging with the public in various ways, such as recording meetings and making them available online, being transparent in sharing information and work products, and producing accessible documents.

2.1. Techniques and Objectives

Puget Sound Energy employed participation techniques designed to achieve specific meeting objectives. Our goal was to align participation objectives and techniques, clearly communicate when and how members of the public could provide input and feedback on report topics, offer straightforward and diverse methods for engagement, and indicate how we used feedback.

2.1.1. Transparency and Accessibility

To support and align key project milestones and decision points, we conducted brainstorming sessions weeks before every public meeting to develop clear objectives.

Puget Sound Energy's public participation practices prioritize transparency and accessibility. These practices include:

- Making comments from members of the public about the 2023 Gas IRP and its development, including responses addressing how the input was considered or used, available on the PSE website
- Making data inputs and files used to develop the 2023 Gas Utility IRP available
- Making meeting summaries and materials from 2023 Gas Utility IRP public meetings publicly available on the PSE website
- Making presentation materials available to the public at least three business days before each meeting
- Outlining the report schedule, public meeting schedule and significant topics to be covered on the PSE website (pse.com/irp)
- Providing transcripts of the chat log from public meetings and enabling live closed captioning

2.1.2. Public Webinars

We continued to practice safety measures to prevent the spread of COVID-19. As a result, we hosted all public engagement activities via webinars. We designed these webinars to engage the public about critical milestones and topics in developing this IRP. During each webinar, those who participated could ask questions and provide feedback verbally or through the online chat feature. Triangle Associates facilitated participation to allow PSE staff to focus on the technical content of the presentations. If we could not answer a question during the meeting, we added it to the meeting feedback report, and PSE responded in writing. We mailed meeting reminders one week before each webinar to alert interested parties that we had posted the meeting materials at pse.com/irp and that feedback forms were open. PSE posted the webinar recordings and chat transcripts two days after each meeting to pse.com/irp.

2.1.3. Webinar Recordings

We recorded all webinars and posted them online two days after the meeting. The recordings included a voice recording, thumbnail versions of the slides we used to support the meeting discussion, and a written transcript for easy searching. We also included the speakers' names in the transcript. We used the webinar recordings to promote participation by those who could not attend but wanted to stay involved and provide feedback. We accepted all input, whether the participant attended the webinar or not.

2.1.4. Webinar Chat Log

PSE conducted all webinars via Zoom. All comments and questions received through the online chat feature were documented in the webinar chat log and posted online two days after each meeting. The chat log documentation includes a list of all attendees along with a name, timestamp, and the comment made by each participant. We answered participant questions verbally and from the written chat. We captured these answers in each webinar recording. We added any questions not addressed during the webinar to the feedback report and answered those questions in writing.

2.1.5. Feedback Forms

PSE designed an online feedback form and posted it at pse.com/irp/get-involved/give-feedback to promote topic-specific suggestions and questions related to each public webinar. The feedback form was opened one week before the webinar and closed one week after the meeting. Members of the public used the online feedback form to submit questions regarding the webinar presentation in advance of the meeting, and we typically answered those questions during the webinar. Following the webinar, members of the public used the feedback form to provide specific input regarding the report analysis and materials presented. Members of the public could also submit questions and comments at any time at pse.com/irp through a general comment form.

2.1.6. Feedback Reports

We prepared and posted feedback reports to pse.com/irp four weeks after each meeting. These reports included input, questions, and comments received from members of the public and written responses to feedback. The goal was to promote accountability and foster two-way communication. When we did not have sufficient time to respond to all participant feedback during a meeting, and if follow-up meetings were necessary to clarify input, the team provided a written response in the feedback report.

2.1.7. Meeting Summaries

PSE prepared and posted summaries of public meetings to pse.com/irp four weeks after each meeting, along with the feedback report. These summaries documented the major feedback themes we identified along with the feedback we received, reported on how we responded to feedback, and documented how we incorporated the feedback into this IRP.

2.1.8. Other Communication Tools

In addition to the techniques described, PSE also used the following communications tools:

- PSE sent email reminders about upcoming deadlines, webinars and registration information, and invitations to submit feedback forms and participate in surveys.
- PSE sent periodic email newsletters to remind the public about upcoming webinars and deadlines and included summaries of public feedback and updates on the status of the report's development.
- Triangle Associates conducted phone interviews with interested members of the public before public engagement meetings to discuss key concerns and explore process improvements.

3. Participants

One-hundred and fourteen organizations and 222 unique individuals participated in the development of this IRP. The participating organizations are listed below.

1890 & Co

Absaroka Energy LLC

Atlas RP

Auto Grid

Avangrid Renewables

Avista

BayWa r.e.

Beacon Energy

Bonneville Power Association

Brightnight Power

Broadreach Power

BV Power

C Power Energy Management

Cadmus Group

Cascade Natural Gas

Chelan PUD

City of Des Moines

City of Enumclaw

City of Issaquah

City of Lake Forest Park

City of Mercer Island

City of Olympia

City of Poulsbo

City of Redmond

City of Seattle

City of Tacoma

Clearway Energy

Climate Solutions

Con Edison Clean Energy Business

Convergent Energy + Power

DNV

Ease Engineers

EcoPlexus

Elemental Energy

ENEL

Energy GPS

Energy Solution

Eolian Energy

esVolta

Flex Charging

Franklin Energy

Frontier Energy

General Electric

Generac Power Systems

Glarus Group

Guidehouse Consulting

Hardy Energy

Hecate Energy

Hull Street Energy

IATC

IBV Energy

ICF Energy

Innergex

Invenergy

Ironworkers Local 86

Jera Americas

King County

Laborers Local 242

Laborers Local 252

Lakeridge Resources

Lightsource BP

Lloyd Reed Consulting

Matrixes Corp

Mitsubishi Power Americas

Monolith Energy Consulting

NextEra Energy Resources

Northwest Power and Conservation Council

NW Energy Coalition (NWEC)

Obsidian Renewables, LLC

Optimum Building Consultants

Oracle

Pacific Northwest Utilities Conference Committee (PNUCC)

PA Consulting Group

PAE

Pascoe Energy

PGN

Phil Jones Consulting

Pierce County

Plus Power

Potelco

Power Ex

Q Cells

Renewable Northwest

Rye Development

Sagestone Ventures

Sapere Consulting

Scout Clean Energy

Shell

Sierra Club

Solar Horizon

SPI

SSVP

Storage Alliance

Strata Clean Energy

Strategen Consulting

Sun Energy Systems

Tenaska

The Masthead Group

TransAlta

Triangle Associates

Tuusso Energy LLC

UA Local 32

Washington Solar Energy Industries Association (WASEIA)

Washington State Office of the Attorney General

Washington Utilities and Transportation Commission (UTC)

Wattbridge

Western Energy Board

Western Power Pool

Western Solar

WestRock

Williams Companies

WRSI

Zipcon

4. Feedback Themes

The following section summarizes feedback themes from webinar meeting summaries and feedback reports during the 2023 Gas Utility IRP public participation process. We incorporated feedback into the 2023 Gas Utility IRP where it was feasible and cataloged some feedback to incorporate into the 2025 Gas Utility IRP cycle.

➔ For additional details, please see specific meeting materials and documentation described in Section 6: Meeting Documentation of this document and hosted permanently at pse.com/irp.

4.1. Climate Change Impacts

Before and during this IRP cycle, several interested parties encouraged PSE to incorporate climate change data into the planning process. We recognized the importance of climate change in past cycles but needed additional data to ensure that any analysis that reflected climate change was accurate. We began incorporating forward-looking climate change assumptions rather than historical climate data into load forecasting in this IRP.

➔ Please refer to Chapter Five: Demand Forecast for details regarding how we incorporated climate change into our demand forecast.

4.2. Public Participation Process

Members of the public gave us valuable feedback on ways to improve the public participation and feedback process. We implemented real-time improvements during this cycle and are assessing the process for the next IRP cycle. For more details on the public participation process, see Section 2: Public Participation Approach of this document.

4.3. Electrification Analysis

We developed an electrification analysis scenario for this IRP based on feedback from the public who asked us to incorporate state energy strategy targets. Additionally, we looked at electrification in a gas IRP for the first time. Our analysis found that electrification would significantly increase resource costs. However, considering the ongoing innovations in the decarbonization space, we look forward to conducting additional analysis in future IRP cycles. We are committed to exploring opportunities to reduce emissions in the gas utility. We will refine and update this analysis with the decarbonization requirements in the GRC settlement in the 2025 Gas Utility IRP.

4.4. Embedding Equity

When considering equity in resource planning, it is important to note that no specific guidance exists today to inform how we should embed equity into PSE's 2023 Gas Utility IRP. We recognize, however, that although resource planning is not a decision-making process, it presents opportunities to view critical elements of our work through an equity lens and to make progress toward our equity goals.

For this IRP we took initial steps toward considering equity for the gas utility by including a spatial analysis of vulnerable populations in the conservation potential assessment consistent the low-income programs. Additionally, we initiated a conversation with interested parties, including our Equity Advisory Group (EAG), which will continue into the 2025 Gas Utility IRP cycle.

We expect to expand equity considerations in the 2025 Gas Utility IRP and beyond as we apply lessons learned from equity work across PSE and identify desired outcomes and goals.

4.5. Zero-growth Scenario

Puget Sound Energy considered feedback from interested parties in response to the draft 2023 Gas Utility IRP and made the zero-growth scenario the preferred portfolio for the final 2023 Gas Utility IRP.

4.6. Accessibility and Plain Language

While creating the 2023 Gas IRP PSE took measures to improve accessibility of our written IRP documents, public meetings and website content. Puget Sound Energy also heard from interested parties that they would like PSE to incorporate plain language into IRP documents to remove participation barriers and attract more members of the public into the resource planning process. We are still actively evaluating our content to ensure it meets accessibility standards for individuals with disabilities and encourages laypeople to get involved in our clean energy processes.

5. Timeline, Meetings, and Topics

We conducted all public meetings for this IRP remotely to help prevent the spread of COVID-19 while improving access for interested parties. Each meeting began with an orientation that explained how to participate using the electronic platform. Section 6: Meeting Documentation inthis appendix provides links to documentation for each of the seven webinars.

5.1. January 2022

Date	Description
January 10	Invitation for January 20, 2022, *Energy planning process and next steps for 2022* webinar emailed to an expanded list of approximately 1,500 interested parties with topics including updates on the Clean Energy Implementation Plan (CEIP), work plan for the 2023 Electric Progress Report, incorporating climate change data into the demand forecast, and Conservation Potential Assessment (CPA). The invitation provided a registration link to the first meeting and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted on the PSE IRP page online.
January 13	Meeting materials for the January 20 webinar were posted to pse.com/irp, and a feedback form was opened for input.
January 20	**Energy Planning Process and Next Steps for 2022 Webinar**

Date	Description
	Participant role: Inform and Consult **Meeting platform:** Zoom **Attendance:** 135 participants and the IRP project team PSE provided updates on the CEIP, and work plan for the 2023 Gas Utility IRP, explained climate change in load forecasting, and explained how the Conservation Potential Assessment (CPA) fits into the IRP. Interested parties shared their feedback on climate change models and CPA.
January 24	A recording of the January 20 webinar and the transcript of the meeting chat was posted to pse.com/irp.
January 27	Feedback forms due for January 20 webinar, Energy Planning Process, and Next Steps for 2022; 5 individuals responded.

5.2. February 2022

Date	Description
February 25	A feedback report of comments collected from the feedback form for the January 20 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
February 27	Invitation emailed to an expanded list of approximately 1,500 interested parties for the March 31, 2022, Assumptions for the 2023 Gas Utility Integrated Resource Plan webinar.

5.3. March 2022

Date	Description
March 13	Invitation for March 31 Assumptions for the 2023 Gas Utility Integrated Resource Plan webinar emailed to an expanded list of approximately 1,500 interested parties with listed topics including carbon pricing, resource alternatives and costs, and gas scenarios. Registration link to the webinar was included, and a sign-up or opt-out option for notifications concerning the process. Registration links and webinar information were also posted online.
March 24	Meeting materials for March 31 webinar were posted to pse.com/irp, and a feedback form was opened.
March 31	**Assumptions for the 2023 Gas Utility Integrated Resource Plan Webinar** **Participant role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 68 participants PSE presented information on assumptions of the Gas Utility IRP timeline, carbon pricing and social cost of greenhouse gas emissions, resource alternatives and costs, and gas scenarios.

5.4. April 2022

Date	Description
April 2	A recording of the March 31 webinar and the chat transcript were posted to pse.com/irp.
April 7	Feedback forms were due for March 31 webinar; two individuals responded.

5.5. May 2022

Date	Description
May 1	A feedback report of comments collected from the feedback form for the March 31 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
May 5	Invitation for June 6 Electric and gas delivery system planning webinar emailed to an expanded list of 1,500 individuals with listed topics including Delivery System Planning (DSP) overview, modernization investments, DSP advancements, and distribution and transmission interconnection cost. It also included a save the dates for all upcoming 2022 IRP meetings and legislative updates. A registration link to the webinar was included, along with a sign-up or opt-out option for notifications. Registration links and information were also posted online.
May 27	Meeting materials for June 6 webinar were posted to pse.com/irp, and the feedback form was opened.

5.6. June 2022

Date	Description
June 2	The second reminder was emailed to interested parties for the Electric and Gas Delivery System Planning (DSP) Webinar.
June 6	**Electric and Gas Delivery System Planning (DSP) Webinar** **Participant role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 77 participants PSE presented on Delivery System Planning ongoing work, Delivery System Planning — Integrating different voices, and Resource Interconnection Costs.
June 13	Feedback forms were due for June 6 webinar; four individuals responded.
June 17	Invitation for July 12 *Electric and gas demand forecast* webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including the demand forecast assumptions, electric and gas forecast results, and electric vehicle forecast. Registration link to the webinar was included along with a sign-up or opt-out option for notifications. Registration links and information were also posted online.

5.7. July 2022

Date	Description
July 1	A report of comments collected from the feedback form for the June 6 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
July 5	Meeting materials for July 12 webinar posted to pse.com/irp, and a feedback form was opened.
July 12	**Electric and Gas Demand Forecast Webinar** **Participant role:** Inform and Consult **Meeting platform**: Zoom **Attendance:** 64 participants PSE presented natural gas results, electric results, demand forecast assumptions, and the electric vehicle forecast.
July 14	July 12 webinar recording, and chat posted to pse.com/irp.

Date	Description
July 22	Feedback forms due for July 12 webinar; one individual responded.

5.8. August 2022

Date	Description
Aug. 12	A feedback report of comments collected from the feedback form for the July 12 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
Aug. 29	Invitation for September 22 webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including final resource need, Conservation Potential Assessment results, and final gas scenarios and gas alternatives. Registration link to Webinar was included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.

5.9. September 2022

Date	Description
Sept. 15	Meeting materials for September 22 webinar were posted to pse.com/irp, and a feedback form was opened.
Sept. 22	**Gas Utility IRP: Inflation Reduction Act, final scenarios and gas alternatives, Conservation Potential Assessment (CPA) results, and Climate Commitment Act (CCA) Pricing** **Participant role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 54 participants PSE presented updates on gas scenarios and sensitivities, CPA results, integration of the Inflation Reduction Act into IRP planning, and next steps for the 2023 Gas Utility IRP.
Sept. 24	September 22 webinar recording and chat posted to pse.com/irp.
Sept. 29	Feedback forms were due for September 22 webinar; 2 individuals responded

5.10. October 2022

Date	Description
Oct. 21	A feedback report of comments collected from the feedback form for the September 22 webinar, along with PSE's responses and a meeting summary posted to pse.com/irp.
Oct. 20	Date change announcement for December 12 webinar, originally scheduled for November 17, was emailed to an expanded list of approximately 1,500 individuals with listed topics, including draft portfolio results for the 2023 Electric Progress Report and 2023 Gas Utility IRP.

5.11. November 2022

Date	Description
Nov. 29	Cancellation announcement for the gas portfolio portion of the December 12 webinar was emailed to approximately 1,500 IRP email subscribers.

5.12. December 2022

Date	Description
Dec. 14	Invitation for January 17 webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including gas portfolio resource planning and modeling results.

5.13. January 2023

Date	Description
Jan. 10	Meeting materials for January 17 webinar were posted to pse.com/irp, and a feedback form was opened.
Jan. 17	**Draft results of gas portfolio webinar** **Participant role**: Inform and Consult **Attendance:** 59 participants PSE delivered an overview of the 2023 Gas Utility IRP modeling process and the preferred portfolio.
Jan. 24	Draft 2023 Gas Utility IRP was posted online at pse.com/irp.
Jan. 24	Feedback forms due for January 17 webinar.

5.14. February 2023

Date	Description
Feb. 7	Feedback forms due for Draft 2023 Gas Utility IRP.
Feb. 27	Invitation for March 14 *Final portfolio results of the 2023 Electric Progress Report and Gas Utility IRP* webinar emailed to the expanded list of approximately 1,500 individuals with listed topics, including final draft results for the electric and gas portfolio. Registration link to webinar included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information were posted online.

5.15. March 2023

Date	Description
March 7	Meeting materials for March 14 webinar was posted to pse.com/irp
March 14	**Final portfolio results of the 2023 Electric Progress Report and Gas Utility IRP Webinar** **Participant role:** Inform **Attendance:** TBD In this webinar, PSE explained the market risk assessment and results of the stochastic analysis along with the preferred portfolios and background concerning the approach and methodology. PSE also explained how public feedback shaped the resource plan in both the Electric Progress Report and the Gas IRP.
March 16	Meeting recording and chat log for March 14 webinar posted to pse.com/irp
March 24	Meeting summary for March 14 webinar posted to pse.com/irp.

6. Meeting Documentation

Links to materials for each 2023 report webinar are included below and posted on pse.com/irp.

6.1. January 20, 2022 Webinar

Topic: Energy planning process and next steps for 2022

- Agenda
- Presentation
- 2022 Climate Change Data Calculation [Excel]
- Chat log
- Meeting recording
- Meeting summary

6.2. March 31, 2022 Webinar

Topic: Assumptions for 2023 Gas Utility Integrated Resource Plan

- Hot Sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.3. June 6, 2022 Webinar

Topic: Electric and gas delivery system planning

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.4. July 12, 2022 Webinar

Topic: Electric and gas demand forecast

- Hot sheet
- Agenda

- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.5. September 22, 2022 Webinar

Topic: 2023 Gas Utility IRP: Inflation Reduction Act, final scenarios and gas alternatives, Conservation Potential Assessment (CPA) results, and Climate Commitment Act (CCA) pricing

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report

6.6. January 17, 2023 Webinar

Topic: Updates and feedback on draft results of electric portfolios

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary

6.7. March 14, 2023 Webinar

Topic: Final portfolio results of the 2023 Electric Progress Report and 2023 Gas Utility IRP

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary

LEGAL REQUIREMENTS
APPENDIX B

PSE PUGET SOUND ENERGY

Contents

1. Introduction

Puget Sound Energy (PSE) is a gas and electric utility regulated by the Washington State Utilities and Transportation Commission (Commission). As part of a regulated industry, PSE must comply with specific requirements and laws. The 2023 Gas Utility IRP follows the regulatory requirements codified in WAC 480-90-238[1]. This chapter walks through the laws and regulations related to the gas utility and explains how PSE meets these requirements through this IRP document. This document also updates the action plan for the 2021 Integrated Resource Plan (IRP).

2. Regulatory Requirements

Table B.1 lists the regulatory requirements currently in effect in WAC 480-90-238[1] that apply to natural gas integrated resource plans. Table B.2 details additional natural gas utility requirements according to RCW 80.28.380[2] and 80.28.405[3]. Finally, Table B.3 details relevant conditions from the Commission's approval of PSE's 2021 natural gas conservation potential assessment, as outlined in Order 01, dated October 14, 2021, in Docket UG-210461. These tables identify the chapters and appendices of PSE's 2023 Gas Utility IRP that address each requirement.

Table B.1: Natural Gas Utility Integrated Resource Plan Regulatory Requirements Codified in WAC 480-90-238[1]

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238(3)(a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type, and efficiency of natural gas end-uses.	• Chapter Four: Key Analytical Assumptions • Chapter Five: Demand Forecast • Appendix D: Demand Forecasting Models
WAC 480-90-238(3)(b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	• Chapter Six: Gas Analysis • Appendix F: Gas Methodology and Results • Appendix C: Conservation Potential Assessment
WAC 480-90-238(3)(c) An assessment of conventional and commercially available nonconventional gas supplies.	• Chapter Four: Key Analytical Assumptions • Chapter Six: Gas Analysis • Appendix F: Gas Analysis Results
WAC 480-90-238(3)(d) An assessment of opportunities for using company-owned or contracted storage.	• Chapter Six: Gas Analysis • Appendix F: Gas Methodology and Results
WAC 480-90-238(3)(e)	• Chapter Six: Gas Analysis

1 WAC 480-90-238
2 RCW 80.28.380
3 RCW 80.28.405

Statutory or Regulatory Requirement	Chapter and/or Appendix
An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	• Appendix F: Gas Methodology and Results
WAC 480-90-238(3)(f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	• Chapter Six: Gas Analysis • Appendix F: Gas Methodology Results • Appendix C: Conservation Potential Assessment
WAC 480-90-238(3)(g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.	• Chapter Two: Resource Plan
WAC 480-90-238(3)(h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	• Chapter One: Executive Summary
WAC 480-90-238(3)(i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	• Appendix B: Legal Requirements (this document)
WAC 480-90-238(4) Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	• 2023 Gas Utility Integrated Resource Plan Work Plan (April 1, 2022) • Updated Gas Utility Integrated Resource Work Plan (October 21, 2022) • Updated Gas Utility Integrated Resource Work Plan (December 15, 2022)
WAC 480-90-238(5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	• Appendix A: Public Participation

Table B.2: Additional Natural Gas Utility Integrated Resource Plan from RCW 80.28[4]

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 80.28.380	• Chapter Six: Gas Analysis

4 RCW 80.28

Statutory or Regulatory Requirement	Chapter and/or Appendix
Each gas company must identify and acquire all conservation measures that are available and cost-effective. Each company must establish an acquisition target every two years and must demonstrate that the target will result in the acquisition of all resources identified as available and cost-effective. The cost-effectiveness analysis required by this section must include the costs of greenhouse gas emissions established in RCW 80.28.395. The targets must be based on a conservation potential assessment prepared by an independent third party and approved by the commission. Conservation targets must be approved by order by the commission. The initial conservation target must take effect by 2022.	• Appendix F: Gas Methodology and Results • Appendix C: Conservation Potential Assessment
RCW 80.28.405 For the purposes of section 11 of this act, the cost of greenhouse gas emissions resulting from the use of natural gas, including the effect of emissions occurring in the gathering, transmission, and distribution of natural gas to the end user is equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in table 2, Technical Support Document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.	• Chapter Four: Key Analytical Assumptions • Chapter Six: Gas Analysis • Appendix F: Gas Methodology and Results

Table B.3: Natural Gas Utility Conservation Potential Assessment Conditions from Commission Order 01 in Docket UG-210461

Commission Condition	Chapter and/or Appendix
Condition 1, Paragraph 11 Increase the Transparency of Subsequent CPA Filings. The Company will file the full CPA model (confidentially where necessary) with the Commission when seeking approval of the CPA. The Company will coordinate one or more structured, technical discussions as the CPA is developed to discuss the CPA model with Commission staff, other interested stakeholders, and the independent third party performing the CPA. The Company will work with Staff to establish a timeline and additional supporting documentation required for Staff review.	PSE filed the CPA with the 2023 Gas Utility IRP on March 31, 2023 PSE conducted three structured technical discussions as the CPA was being developed with commission staff and other participants as follows: • Jan 12, 2022: Kickoff • April 7, 2022: Measure Characterization update • July 27, 2022: Draft results of the CPA

3. 2021 Natural Gas Sales Short-term Action Plan

We identified a few areas for PSE to act on in the 2021 IRP. The following sections provide a summary of the commitments we made in the 2021 IRP and an update on our progress.

3.1. Acquire Energy Efficiency

In the 2021 IRP, we committed to developing two-year targets and implementing programs to acquire conservation, with the 2021 plan as a starting point for our goals. The 2021 IRP included adding 12 MDth per day of capacity by 2024 through program savings and savings from codes and standards.

Progress: Puget Sound Energy set a target of 9.726 million therms for the 2022–2023 program cycle. Supply chain disruptions, inflation, and labor shortages from the pandemic have made it challenging to achieve the targets. The residential programs have reached 28.7 percent of the 2022 target, and we forecast them to reach 56.6 percent of the target by the end of 2023. The business programs achieved 20 percent of the target in 2022, and we forecast they will achieve another 16 percent of the savings target in 2023. Overall the programs are forecasted to archive 93.2 percent of the biennial goal.

In addition to the originally planned activities for 2022, we have taken many steps to help customers save more energy, including:

Residential Programs:

- Added Home Energy Report customer groups for gas-only and low-to-moderate income customers.
- Added limited time offers on:
  - Foodservice equipment
  - Heat pump water heaters
  - Single-family weatherization
  - Thermostats with four manufacturer agreements
- Advanced equitable design and implementation empowered by the draft Clean Energy Implementation Plan (CEIP), updated named community dashboard, training, and ongoing program assessments, accelerated by a new Equity Product Manager that started in Q4 2022.
- Conducted outreach and relationship building via community-based organizations for residential and small businesses.
- Implemented low-income weatherization measure cost updates on 9/26/22, with a full suite of measure cost updates for 2023.
- Improved Efficiency Boost customer journeys via an improved website, translated materials, and expanded customer do-it-yourself (DIY) options.
- Partnered with Energy Smart Eastside on their program design and customer education.

Business Programs:

- Added limited-time offers on business lighting contractor performance incentive through 2023.

- Conducted outreach and marketing:
  - Marketing product and awareness
  - Outreach and relationship building via new account executives
- Implemented changes to current programs:
  - Contracted with a vendor for first-year engagement for gas customers
  - Revised total resource cost threshold
  - Transitioned virtual commissioning pilot to program

3.2. Renewable Natural Gas

In the 2021 IRP, we committed to meeting customer interest in greenhouse gas (GHG) reduction programs through program development and implementation. We also said we would evaluate and develop strategies and pursue cost-effective opportunities for renewable natural gas (RNG) acquisition to support voluntary customer RNG programs and future GHG reduction.

Progress: Puget Sound Energy launched a voluntary product in December 2021 that allows residential and commercial customers to purchase $5 blocks of renewable natural gas for their home or business and receive credit on their bill for the conventional natural gas they replaced with RNG. As of the end of October 2022, 4,899 residential and 51 commercial customers participated in the program, and it is on target to have 12,624 participants by May of 2024.

3.3. Emission Reduction Strategy and Planning

In the 2021 IRP, we committed to exploring potential and voluntary GHG reduction opportunities and developing and evaluating implementing strategies. We also said we would closer align the electric and natural gas modeling processes so we could better evaluate future fuel for power and the gas-to-electric end-use conversions. We committed to exploring the potential of blending clean fuels (hydrogen) with existing pipeline infrastructure and customer end-use applications. We said we would investigate a range of appliances that may help reduce GHG emissions and ensure the reliability of the natural gas and electric system on peak load days.

Progress: In the 2023 Gas Utility IRP, we ran an electrification scenario that included gas and electric models. This analysis included alternative fuels, such as blending green hydrogen, and a range of appliances included as conservation measures and forced into the model. The analysis showed the impact on emissions, resource needs, and costs for the gas and electric portfolios.

➔ This analysis is in Chapter Six: Gas Analysis, and details are in Appendix E: Existing Resources and Alternatives and Appendix F: Gas Methodology and Results.

CONSERVATION POTENTIAL ASSESSMENT

APPENDIX C

PSE PUGET SOUND ENERGY

2023 Gas Utility Integrated Resource Plan

Contents

1. Introduction

We developed the demand-side resource (DSR) alternatives in the Conservation Potential Assessment (CPA) to create a supply curve as an input to the portfolio analysis. The portfolio analysis then determines the maximum energy savings we can capture without raising the overall natural gas portfolio cost, which is also known as the cost-effective level of DSR.

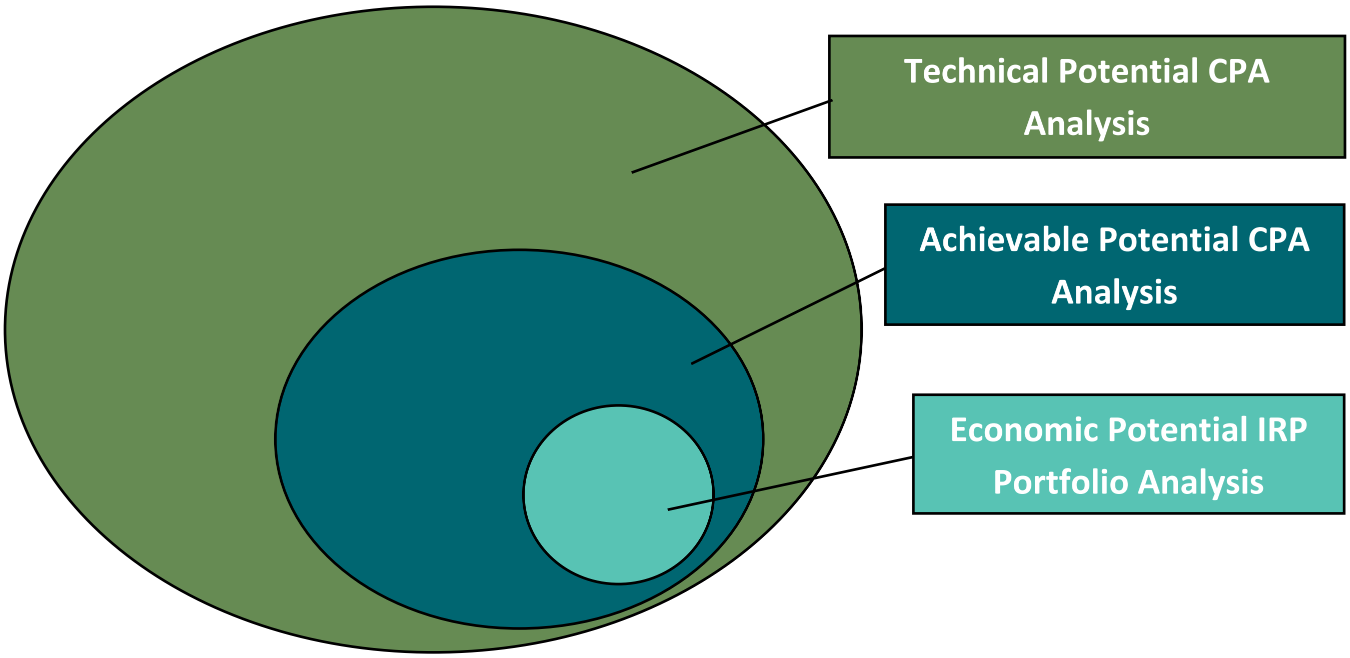
We included the following demand-side resource alternatives in the CPA, which The Cadmus Group (Cadmus) performed for this 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) on behalf of Puget Sound Energy (PSE).

- **Codes and Standards (C&S):** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. In the past IRP cycles, only those that are in place at the time of the CPA study were included, in this IRP we also include the changes to the codes anticipated from state law to make them more stringent over each building code cycle.
- **Electrification:** Electrification replaces end-use technologies based on fossil fuels with those that run on electricity; implicit in this process is that the electricity comes from renewable sources. There are two pathways to electrification: 1) hybrid systems that can reduce the use of fossil fuels to a limited number of peak hours, with reduced impacts on the environment while keeping the impacts on the electrical grid costs lower, and 2) full electrification where the fossil fuel is completely replaced with the electric technology and relies on the electric grid to be able to serve the increasing electric peak loads through additional electric supply resources.
- **Energy efficiency measures:** We used this label for a wide variety of measures that result in a smaller amount of energy used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, space and water heating equipment, and appliance upgrades.
- **Gas Transport:** As part of the Climate Commitment Act (CCA), utilities must include transport gas customers with annual emissions of less than 25,000 tons of CO_2 in the efforts to meet the annual emissions reductions needed to comply with the CCA. Thus, we evaluated gas energy efficiency potential for gas transport customers as part of the 2023 Gas Utility IRP.

2. Treatment of Demand-side Resource Alternatives

The CPA performed by the Cadmus Group on behalf of PSE develops two levels of DSR conservation potential: technical potential and achievable technical potential. The 2023 Gas Utility IRP portfolio analysis then identifies the third level, economic potential. Figure C.1 shows the relationship between the technical, achievable, and economic conservation potentials.

Figure C.1: Relationship between Technical, Achievable and Economic Conservation Potential

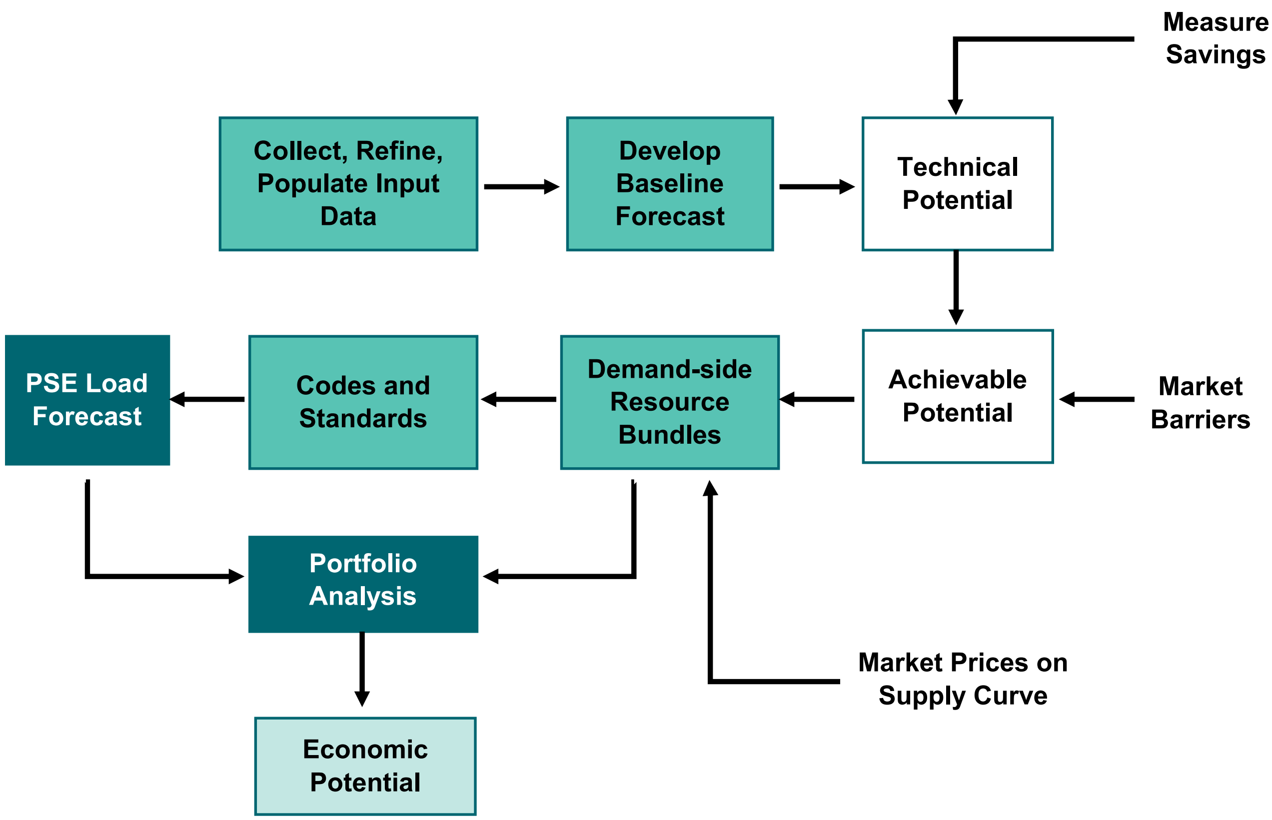


First, the CPA screened each measure for technical potential. This screen assumed we could capture all energy- and demand-saving opportunities regardless of cost or market barriers, which ensured the model surveyed the full spectrum of technologies, load impacts, and markets.

Second, we applied market constraints to estimate the achievable potential. Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment to gauge achievability. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

In the third step, we divide the conservation supply curve consisting of the achievable technical potential measures by cost ranges, arranged from the lowest to the highest cost, also known as cost bundles. This step produces a conservation supply cost curve for use in the IRP portfolio optimization analysis to identify the highest cost bundle that is cost effective, we label this as the economic potential.

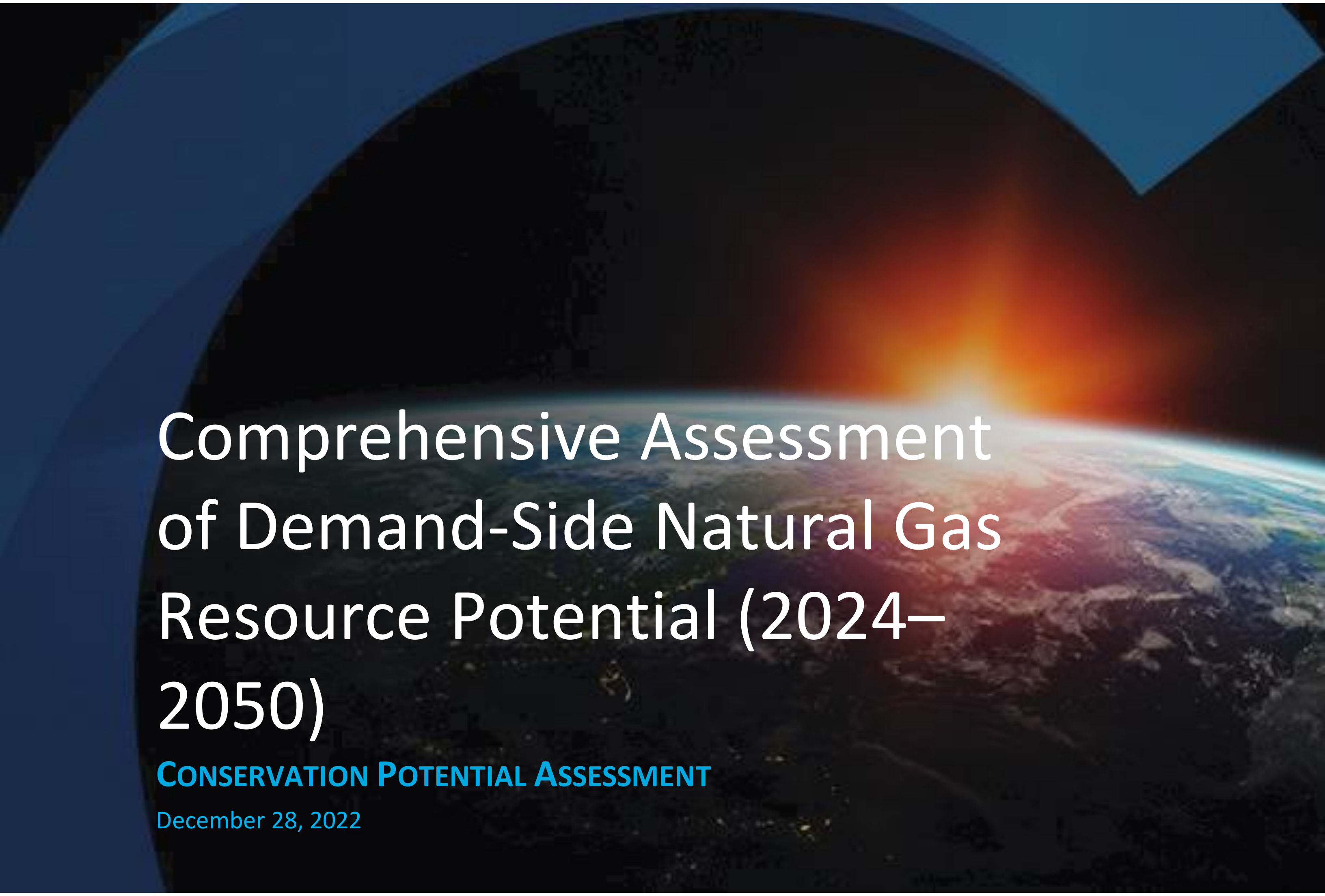
Figure C.2 Methodology to Assess Demand-side Resource Potential in the 2023 Gas Utility IRP



➔ For the results of the Cadmus study, please see the excel file posted under Appendix C: Conservation Potential Assessment.

This appendix contains the CPA report for the 2023 Gas Utility IRP, with a detailed discussion of the measures and the methodology used in developing the conservation supply curves.

CADMUS



Comprehensive Assessment of Demand-Side Natural Gas Resource Potential (2024–2050)

CONSERVATION POTENTIAL ASSESSMENT

December 28, 2022

Prepared for:

Puget Sound Energy
10885 NE 4th Street
Bellevue, WA 98004

Prepared by:
Aquila Velonis
Gamze Gungor Demirci
Andrew Grant
Sophia Spencer

CADMUS

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Acronyms and Abbreviations

Acronym	Definition
ASHP	Air-source heat pump
C&I	Commercial and industrial
CBSA	*Commercial Building Stock Assessment*
Council	Northwest Power and Conservation Council
CPA	Conservation potential assessment
CPP	Critical peak pricing
DHP	Ductless heat pump
DLC	Direct load control
ECM	Energy conservation measure
ERWH	Electric resistance water heater
EUL	Effective useful life
EVSE	Electric vehicle supply equipment
FMY	Future meteorological year
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
IRP	Integrated resource plan
MMTherms	Million therms
NEEA	Northwest Energy Efficiency Alliance
NEI	Non-energy impact
O&M	Operations and maintenance
PSE	Puget Sound Energy
RBSA	*Residential Building Stock Assessment*
RCS	*Residential Characteristics Study*
RCW	Revised Code of Washington
RTF	Regional Technical Forum
T&D	Transmission and distribution
TMY	Typical meteorological year
UEC	Unit energy consumption
UES	Unit energy savings
WSEC	Washington State Energy Code

Executive Summary

This report presents the results of an independent assessment of the technical and achievable technical potential for natural gas demand-side resources in the service territory of Puget Sound Energy (PSE) over the 27-year planning horizon from 2024 to 2050. This conservation potential assessment (CPA), commissioned by PSE as part of its integrated resource planning (IRP) process, is intended to identify demand-side resource potential in terms of energy efficiency. This report also presents the results of an analysis on natural gas–to-electric conversion potential by investigating the effects of replacing natural gas equipment with electric equipment on electric and natural gas system load, evaluating associated measure impacts and costs, estimating electric and natural gas energy efficiency potential, and estimating the impacts of natural gas–to-electric conversion on demand response potential.

The results of this assessment will provide direct inputs into PSE's 2023 IRP and will help PSE to identify cost-effective demand-side resources and design future programming. This study builds upon previous assessments of demand-side resources in PSE's territory and accomplishes several objectives:

FULFILLS WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION REQUIREMENTS set for natural gas assessments pursuant to the Revised Code of Washington (RCW 80.28.380), Gas Companies—Conservation Targets,[1] including conditions PSE agreed upon in the fall of 2021. The RCW requires that PSE identify and acquire all conservation measures that are available and cost-effective.

DEVELOPS UP-TO-DATE ESTIMATES OF ENERGY CONSERVATION datasets for the residential, commercial, and industrial sectors, as well as small transport customers, using measures consistent with PSE's program measures, the Regional Technical Forum (RTF), the Northwest Power and Conservation Council's (Council) draft *2021 Northwest Conservation and Electric Power Plan* (*2021 Power Plan*), and other data sources.

PROVIDES INPUTS INTO PSE'S IRP, which is completed every two years and determines the mixture of supply-side and demand-side resources required over the next 27 years to meet customer demand.

This study incorporates the latest baseline and energy demand-side resource data from various PSE-specific sources (such as PSE program measure business cases); the work of other entities in the region, such as the Council, the Northwest RTF, and the Northwest Energy Efficiency Alliance (NEEA); and other secondary sources (such as various technical reference manuals). The methods we used to evaluate the

[1] Revised Code of Washington. Accessed 2022. "RCW 80.28.380 Gas Companies—Conservation Targets." https://app.leg.wa.gov/RCW/default.aspx?cite=80.28.380&pdf=true

technical and achievable technical energy efficiency potential draw upon best utility industry practices and remain consistent with the methodology used by the Council in its draft *2021 Power Plan* as this assessment was being updated (in January 2022).

New in this CPA compared to prior CPAs, the natural gas study incorporates three additional considerations:

CLIMATE CHANGE	**NON-ENERGY IMPACTS (NEIs)**	**NAMED COMMUNITIES**

Cadmus adjusted weather-sensitive measures for the impacts of climate change, accounted for a wider range of NEIs, and estimated demand-side resource potential for named communities based on PSE's vulnerable population data. In addition, we assessed the impacts of recent state and local codes. All these topics are discussed in more detail in the main chapters of this report.

The PSE CPA results for electric demand-side resource potential in terms of energy efficiency, demand response, and distributed generation (including solar photovoltaics and combined heat and power) can be found in a separate companion report titled *Comprehensive Assessment of Demand-Side Electric Resource Potential (2024–2050)*.

Scope of the Analysis and Approach

This section outlines the scope of the energy efficiency and natural gas–to-electric conversion potential analyses while briefly explaining the approach used for each analysis.

Energy Efficiency

Cadmus estimated the technical and achievable technical potential for more than 175 unique gas energy efficiency measures. The energy efficiency analysis included estimates of the technical and achievable technical potential for natural gas energy efficiency measures. We relied on PSE program data, RTF analysis, the Council's draft *2021 Power Plan* analyses, and regional stock assessments to determine the savings, costs, and applicability for each measure. We also incorporated feedback from PSE staff and regional stakeholders on the list of measures and measure assumptions.

Cadmus prepared 27-year forecasts of potential natural gas energy savings for each energy efficiency measure using an end use–based model. We considered multiple sectors, segments, and vintages, distinguishing between lost opportunity and retrofit measures and accounting for building energy codes as well as future state and federal equipment standards. Achievable technical potential estimates use assumptions that are consistent with the Council's draft *2021 Power Plan*: 85% to 100% of technical potential is achieved over the 27-year study horizon and adoption curves are derived from the Council's draft *2021 Power Plan* ramp rates and 10-year ramp rates for discretionary measures (consistent with PSE's prior CPAs). A detailed discussion of the energy efficiency potential is included in *Chapter 1. Energy Efficiency Potential*.

Energy Efficiency Potential for Small Transport Customer Sector

Small transport is a class of customers who had less than an average of 25,000 tons of annual carbon dioxide emission per Mscf of their natural gas consumption in the time frame of 2015 through 2019. Per the Climate Commitment Act, PSE included their small transport customer sector into this CPA as a compliance requirement.

Natural Gas–to-Electric Conversion Potential

In addition to the energy efficiency technical and achievable technical potential, Cadmus also estimated natural gas–to-electric conversion potential by investigating the effects of replacing natural gas equipment with electric equipment on electric and natural gas system load, evaluating associated measure impacts and costs, and estimating electric and natural gas energy efficiency potential in the residential and commercial sectors. We calculated potential for the industrial sector by converting a portion (~30%) of natural gas loads based on prior analysis by Cadmus.

As part of the natural gas–to-electric conversion potential assessment, Cadmus conducted a heat pump market research study and fielded an online customer survey (862 surveys completed) for measuring the residential sector's willingness to pay for natural gas conversions to heat pumps. We also interviewed contractors and builders (14 interviews completed) in PSE's service territory to determine heat pump (hybrid, ductless, ducted, and other) conversion costs, including any additional costs to convert to electric from non-electric equipment, such as electrical panel or wiring upgrades, duct reconfiguration, and added labor costs. The data collected through the survey and interviews supported the analysis for determining the adaption rates and conversion costs.

For the residential sector, Cadmus conducted the natural gas–to-electric conversion potential analysis under three different scenarios:

HYBRID HEAT PUMP – MARKET

Cadmus analyzed the effects of a conversion from natural gas heating equipment (such as a natural gas furnace and ductless natural gas heating) to a heat pump (such as a ductless and ducted air-source heat pump [ASHP]) while keeping the natural gas heating equipment as the backup. We obtained the market adoption rates for this scenario from the customer survey.

HYBRID HEAT PUMP – POLICY

Cadmus analyzed the effects of a conversion from natural gas heating equipment to a heat pump while keeping the natural gas heating equipment as the backup but, unlike the previous scenario, we adjusted the market adoption rate to a maximum where 100% of applicable residential applications have a hybrid heat pump or ductless system with natural gas back-up. This scenario is meant to represent a policy change where all residential customers are required to convert to a hybrid heat pump at the end of the natural gas equipment's useful life.

FULL ELECTRIFICATION – POLICY

Cadmus analyzed the effects of a conversion from natural gas heating equipment to a heat pump without keeping the natural gas heating equipment and assumed full adoption (where the market adaption rate equals 100%) to represent a policy change banning natural gas usage and forcing all customers to convert to heat pumps at the end of the natural gas equipment's useful life.

All commercial and industrial customers have the same adoption across all scenarios.

Natural gas–to-electric conversion resulted in an increase in electric load and associated electric energy efficiency potential while reducing the natural gas load and associated natural gas energy efficiency potential.[2] Since the CPA looks at the impacts on PSE systems, these impacts are reflected on corresponding services provided by PSE in its territory:

PSE ELECTRIC-ONLY SERVICE AREA	PSE NATURAL GAS-ONLY SERVICE AREA	PSE COMBINATION SERVICE AREA
Increase in PSE electric load	Decrease in PSE natural gas load	Increase in PSE electric load Decrease in PSE natural gas load

As the last step of this natural gas–to-electric conversion potential assessment, Cadmus analyzed the impacts of these changes on demand response potential, with the results presented in the *Effect of Natural Gas-to-Electric Conversion on Demand Response Potential* section of *Chapter 3. Natural Gas-to-Electric Potential Assessment.*

[2] The assessment estimated the load and energy efficiency impact from shifting from natural gas to electric equipment. The base CPA also estimated the impact associated with codes and standards. However this CPA did not revaluate the codes and standards impact accounting for the shift in natural gas to electric conversion.

Summary of Results

Natural gas energy efficiency represents nearly 192 million therms (MMTherms) of 27-year achievable technical potential and produces 44,180 therms of average coincident peak capacity savings[3], for residential, commercial and industrial sectors as well as small transport customers, as shown in Table 1. All estimates of potential in this report are presented at the generator, which means they include line losses of 0.93%.

Table 1. Summary of Energy Savings and Peak Capacity Reduction Potential, Cumulative 2050

Resource	Energy (MMTherm)		Winter Coincident Peak Capacity (Peak Therm)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Energy Efficiency (Residential, Commercial, Industrial)	201	165	48,040	39,625
Energy Efficiency (Transport)	31	26	5,408	4,555

Figure 1 presents the achievable technical potential forecast of natural gas energy efficiency. More savings are achieved in the first 10 years of the study (2024 through 2033) than in the remaining 17 years because the study assumes that discretionary measure potential savings are acquired in the first 10 years (for a selected set of measures that are retrofit in existing homes and businesses). In the remaining years, additional savings come from lost opportunity measures, such as equipment replacement and new construction.

Figure 1. Achievable Technical Potential Forecast, Cumulative 2024–2050

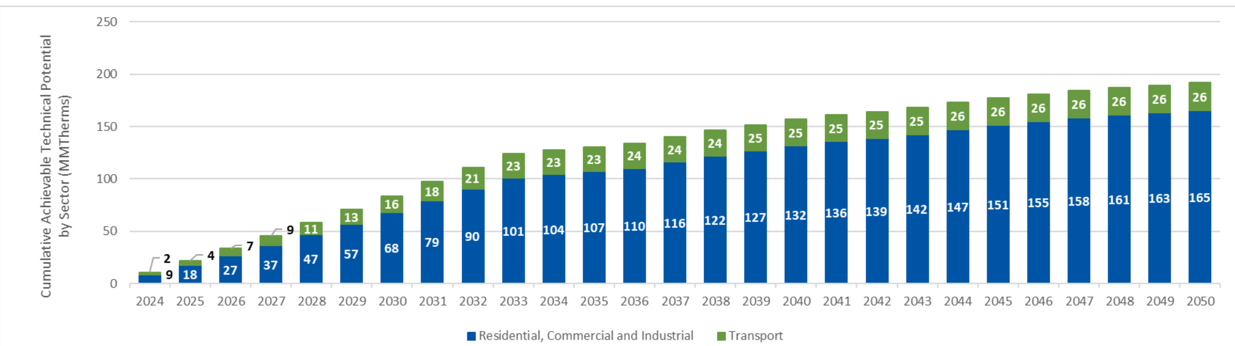

Table 2 presents the total achievable technical potential for natural gas energy efficiency broken out by sector. If the 27-year achievable technical potential is realized, it will produce a load reduction equivalent to 17% of PSE's 2050 baseline natural gas sales. Approximately 58% of this potential is in the residential sector, while 27% is in the commercial sector, 14% is in small transport customer sector, and the remaining 2% is in the industrial sector.

[3] The peak capacity savings represent the average peak impact across all hours occurring in December within hour ending 8AM to hour ending 10AM and hour ending 6PM to hour ending 7PM. This average peak impact does not represent PSE's peak day estimation.

Table 2. Energy Efficiency by Sector, Cumulative 2050

Sector	2050 Baseline Sales (MMTherm)	Achievable Technical Potential	
		MMTherm	Percentage of Baseline Sales
Residential	617	111	18%
Commercial	293	51	18%
Industrial	18	3	18%
Transport	178	26	15%
Total	**1,106**	**192**	**17%**

Comparison to 2021 CPA

Cadmus incorporated some changes in the 2023 energy efficiency analysis since the completion of PSE's previous CPA in 2021:

- Used an end-use–based approach instead of a units-based approach, as was used in 2021 CPA. This end-use approach is more dynamic for end-use scenario analysis and includes the ability to better account for climate change and natural gas–to-electric load impacts.
- Used PSE's most recent "2022 Demand Forecast" for energy and number of customers.
- Incorporated assumptions for savings, cost, and measure lives derived from PSE's 2022 measure business cases and the RTF's unit energy savings (UES) workbook updates as of January 2022.
- Used the most recent PSE-specific data and regional stock assessments to determine saturations and applicability, including PSE's 2021 Residential Characteristics Study (RCS), NEEA's 2017 *Residential Building Stock Assessment II* (RBSA), and NEEA's 2019 *Commercial Building Stock Assessment* (CBSA),[4] which is PSE-specific for some segments.
- Accounted for recent PSE program accomplishments from high impact program measures (commercial lighting, HVAC equipment, etc.)
- Accounted for the tightening Washington State Energy Code (WSEC) (RCW 19.27A.160),[5] which requires that "… residential and nonresidential construction permitted under the 2031 state energy code achieve a 70% reduction in annual net energy consumption, using the adopted 2006 Washington state energy code as a baseline."

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[4] Cadmus. May 21, 2020. *Commercial Building Stock Assessment 4 (2019)*. "CBSA 4 Appendix Tables (Weighted)." Prepared for Northwest Energy Efficiency Alliance. https://neea.org/resources/cbsa-4-appendix-tables-weighted

[5] Revised Code of Washington. Accessed August 24, 2022. "RCW 19.27A.160 Residential and Nonresidential Construction— Energy Consumption Reduction—Council Report." https://app.leg.wa.gov/RCW/default.aspx?cite=19.27A.160

- Accounted for updates in the Seattle Building Energy Code, which requires all new commercial buildings and large multifamily buildings above three stories to use clean electricity for space and water heating and to maximize building efficiency and on-site renewables like solar.[6]
- Accounted for ordinances passed by city of Shoreline[7] and city of Bellingham[8] for promoting energy efficiency and the decarbonization of commercial and large multifamily buildings and requiring solar readiness for new buildings.
- Accounted for recent changes to federal equipment standards.
- Accounted for the impacts of climate change by using *2021 Power Plan* data and PSE's load forecast and by adjusting weather-sensitive measures by applying the Council's typical meteorological year (TMY) to projected future meteorological year (FMY) adjustment factors to weather-sensitive RTF and PSE business case measures by calibrating the CPA heating end uses with PSE's climate impacts within the annual load forecast.
- Considered a wider range of NEIs (such as comfort, productivity, and health) based on a recent study conducted for PSE.[9]
- Estimated the demand-side resource potential for named communities based on PSE's recent vulnerable population data. This data has a somewhat similar overlay as highly impacted communities, defined by the Washington State Department of Health according to a ranking based on environmental burdens (including fossil fuel pollution and vulnerability to climate change impacts that contribute to health inequities), and best aligned with CPA geographic areas (county-level areas built up from block groups).
- Expanded the bundles on the supply curve and increased the number of bundles from 12 to 18.

Table 3 shows a comparison of the 20-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2023 and 2021 CPAs. Overall, the 2023 CPA identified 18% lower natural gas achievable technical potential.

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6 The implementation of space and water heating measures took effect in January 2022. The rest of the code went into effect on March 15, 2021 (see Christensen, Eric L., Kirstin K. Gruver, and Rujeko A. Muza. February 4, 2021. "Seattle Bans Natural Gas in New Buildings." *The National Law Review* (Volume XII), Number 241. https://www.natlawreview.com/article/seattle-bans-natural-gas-new-buildings).

7 Ordinance No. 948 "Ordinance of the City of Shoreline, Washington Amending Chapter 15.05, Construction and Building Codes, of the Shoreline Municipal Code, to Provide Amendments to the Washington State Energy Code – Commercial, as Adopted by the State of Washington" took effect on July 1, 2022.

8 "Ordinance of the City of Bellingham Amending Bellingham Municipal Code Chapter 17.10 – Building Codes, to Provide Amendments to the Washington State Energy Code – Commercial, Promoting Energy Efficiency and the Decarbonization of Commercial and Large Multifamily Buildings and Requiring Solar Readiness for New Buildings" took effect on August 7, 2022.

9 DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report*.

Table 3. Energy Efficiency Comparison of 2023 CPA and 2021 CPA

Study	20-Year Achievable Technical Potential (Percentage of Sales)			Total Achievable Technical Potential (MMTherms)
	Residential	Commercial	Industrial	
2023 CPA	15%	16%	17%	142
2021 CPA	19%	7%	8%	174

Note: This table shows a comparison of 20-year results from the 2023 CPA to 20-year results from the 2021 CPA. The 2023 CPA total achievable technical potential differs from the amount shown in Table 2, which presents the full 27-year potential study results. The 2023 CPA total achievable technical potential is excluding small transport customers, as this sector was not included in the 2021 CPA.

Several factors contributed to the significant changes in natural gas energy efficiency potential between the 2021 CPA and 2023 CPA:

NEW CONSTRUCTION

- Reduction in new construction (residential and commercial) achievable technical potential due to state and local code updates.

RESIDENTIAL

- Reduction in showerhead potential due to the Washington Administrative Code (WAC 51-56-0400).
- Lower residential natural gas furnace potential through lower unit energy consumption (UEC) due to climate change impacts and an associated decrease in heating loads.

COMMERCIAL

- Higher potential identified in higher cost measures such as building management systems and retro-commissioning.
- Updated customer segmentation that impacted the characterization and distribution of potential within each segment.

INDUSTRIAL

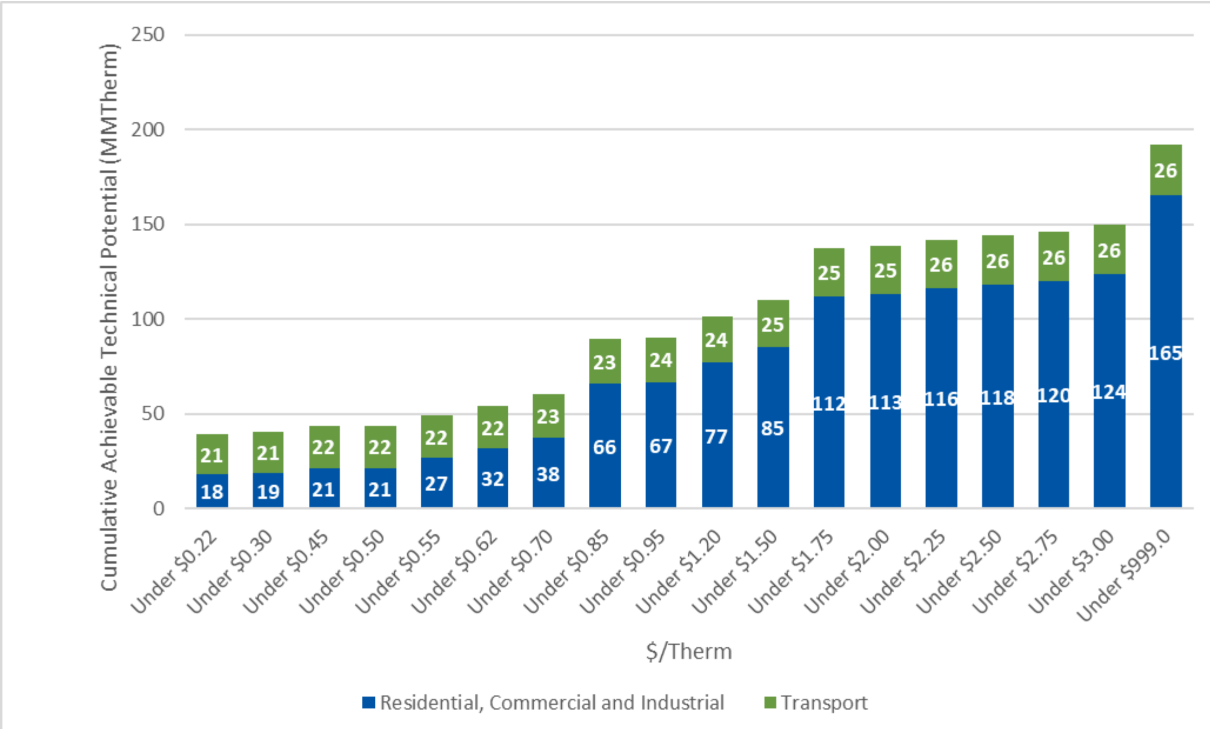
- Updated customer segmentation that impacted the characterization and distribution of potential within each segment.

Incorporating Demand-Side Resources into PSE's Integrated Resources Plan

Cadmus grouped the achievable technical potential shown above by the levelized cost of conserved energy for inclusion in PSE's IRP model. We calculated these costs over a 27-year study period. The *Integrated Resource Plan Input Development* section of *Chapter 4. Energy Efficiency Methodology Details* provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of annual demand-side resources based on expected load growth, energy prices, and other factors. Cadmus provides IRP input data by levelized cost bundle (or bins) and we did not incorporate an economic screen on the demand-side resources; instead, we used the CPA IRP inputs to inform PSE's optimization modeling that select the least-cost (most cost-effective) resource.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce monthly demand-side resource bundles as well as locational estimates by PSE service area zip code. In addition, we assumed that savings are gradually acquired over the year, as opposed to instantly happening on the first day of January. PSE provided intra-year demand-side resource acquisition schedules, which we used to ramp savings across months. Figure 2 shows the annual cumulative potential for energy efficiency by each cost bundle considered in PSE's 2023 IRP.

Figure 2. Natural Gas Supply Curve – Cumulative 27-Year Achievable Technical Potential



Organization of This Report

This report presents the findings of demand-side natural gas resource potential assessment in several chapters and four appendices:

- *Chapter 1. Energy Efficiency Potential* includes an overview of the methodology Cadmus and PSE used to estimate technical and achievable technical potential as well as detailed sector, segment, and end-use–specific estimates of conservation potential for the residential, commercial, and industrial sectors. This chapter also presents a discussion of the top-saving measures in each sector and comparison with PSE's 2021 CPA.
- *Chapter 2. Energy Efficiency Potential for Small Transport Customer Sector* presents and discusses the forecasts of technical and achievable technical potential for the small transport customer sector.
- *Chapter 3. Natural Gas-to-Electric Potential* presents and discusses the results of three different scenarios Cadmus ran on energy efficiency potential as explained above. This chapter also presents the impacts of natural gas-to-electric conversion on demand response potential.
- *Chapter 4. Energy Efficiency Methodology Details* describes Cadmus' combined top-down, bottom-up modeling approach for calculating technical and achievable technical potential by giving details on the steps for estimating energy efficiency potential.
- *Appendix A* presents the heat pump market research findings in the form of PowerPoint slides.
- *Appendix B* presents heat pump customer survey questions.
- *Appendix C* presents heat pump contractor interview questions.

- *Appendix D* presents heat pump builder interview questions.

Chapter 1. Energy Efficiency Potential

PSE requires accurate estimates of technical and achievable technical energy efficiency potential, which are essential for its IRP and program planning efforts. PSE then bundles these potentials in terms of the levelized costs of conserved energy so the IRP model can be used to determine the optimal amount of energy efficiency potential.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for natural gas resources in the residential, commercial, industrial, and small transport customer sectors. The *Energy Efficiency Potential - Methodology Overview* section gives an overview of the methodology we used for this purpose, which is then described in greater detail in *Chapter 4. Energy Efficiency Methodology Details*. The methodology below is followed by an explanation of considerations about the design of this potential study. Lastly, the results of energy efficiency potential assessment for residential, commercial, and industrial sectors are presented in detail. The results for small transport customer sector are discussed separately in *Chapter 2. Energy Efficiency Potential for Small Transport Customer Sector*.

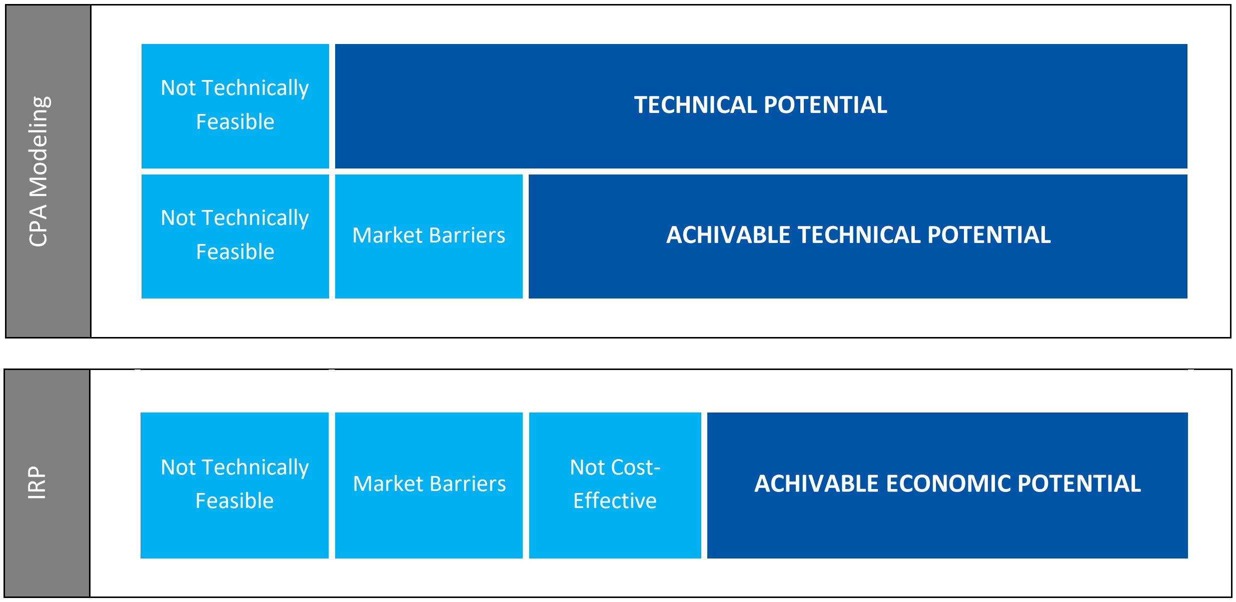
Energy Efficiency Potential - Methodology Overview

Consistent with the Washington Administrative Code requirements, Cadmus assessed two types of energy efficiency potential—technical and achievable technical. PSE determined a third type of potential—achievable economic—through the IRP's optimization modeling. These three types of potential are illustrated in Figure 3.

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total energy efficiency potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential assumed to be achievable during the study's forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical potential determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on costs and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which PSE then entered as variables in the IRP's optimization model to determine achievable economic potential.

Figure 3. Types of Energy Efficiency Potential



The timing of resource availability is a key consideration in determining conservation potential. There are two distinct categories of resources:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization and shell upgrades, furnace tune-ups, and low-flow showerheads.
- ***Lost opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include HVAC equipment, water heaters, and appliances.

Cadmus analyzed four sectors—residential, commercial, industrial, and small transport—and, where applicable, considered multiple market segments, construction vintages (new and existing), and end uses. The details of small transport customer sector are given separately in *Chapter 2. Energy Efficiency Potential for Small Transport Customer Sector*.

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
SIX SEGMENTS Single family, multifamily, manufactured, single family - vulnerable population, multifamily - vulnerable population, and manufactured - vulnerable population	**EIGHTEEN SEGMENTS** Office, retail, and food sales segments further divided into categories based on building size, aligning with the *2021 Power Plan*	**EIGHTEEN SEGMENTS** Paper, chemical, wood, hi-tech, and additional manufacturing segment types that align with the *2021 Power Plan*

For this study, Cadmus defined PSE's named communities and equity to represent the vulnerable population and highly impacted communities within the PSE's service area (defined on the right). We reviewed the data available and determined that the vulnerable population data best aligned with the CPA geographic areas (such as the county level built up from block groups). As a result, we used the vulnerable population data (over the highly impacted communities data) as basis of our analysis within this study. Cadmus segmented PSE residential accounts for vulnerable populations by county and used PSE 2021 RCS data to inform equipment saturations and fuel shares for the vulnerable population (based on income).

Vulnerable Populations Attributes
Identified as socioeconomic factors including unemployment, high housing and transportation costs relative to income, low access to food and health care, and linguistic isolation. Includes sensitivity factors, such as low birth weight and higher rates of hospitalization.

Highly Impacted Communities
Ranks communities with environmental burdens including fossil fuel pollution and vulnerability to climate change impacts that contribute to health inequities. Includes any census tract with tribal lands.

Cadmus used an end-use approach to forecast energy efficiency potential in all four sectors, taking several primary steps:

- Developed the baseline forecast by determining the 27-year future energy consumption by segment and end use. Calibrated the base year (2023) to PSE's sector level load forecast produced in 2022. Baseline forecasts in this report included the estimated impacts of climate change and of codes and standards on commercial and residential energy usage.
- Estimated technical potential based on the incremental difference between the baseline load forecast and an alternative forecast reflecting the technical impacts of specific energy efficiency measures.
- Estimated achievable technical potential by applying ramp rates and achievability percentages to technical potential, described in greater detail in *Chapter 4. Energy Efficiency Methodology Details*.

There are two advantages offered by this approach:

- Savings estimates were driven by a baseline forecast that is consistent with the assumptions used in PSE's adopted 2022 corporate load forecast.
- It helped to maintain consistency among all assumptions underlying the baseline and alternative forecasts for technical and achievable technical potential. The alternative forecasts used different relevant inputs at the end-use level to reflect energy conservation measure (ECM) impacts. Because estimated savings represent the difference between baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Cadmus' methodology can be best described as a combined top-down, bottom-up approach for the residential and commercial sectors. As shown in Figure 4, we began the top-down component with the most current load forecast, adjusting for building codes, equipment efficiency standards, and market trends. Cadmus then disaggregated this load forecast into its constituent customer sectors, customer segments, and end-use components.

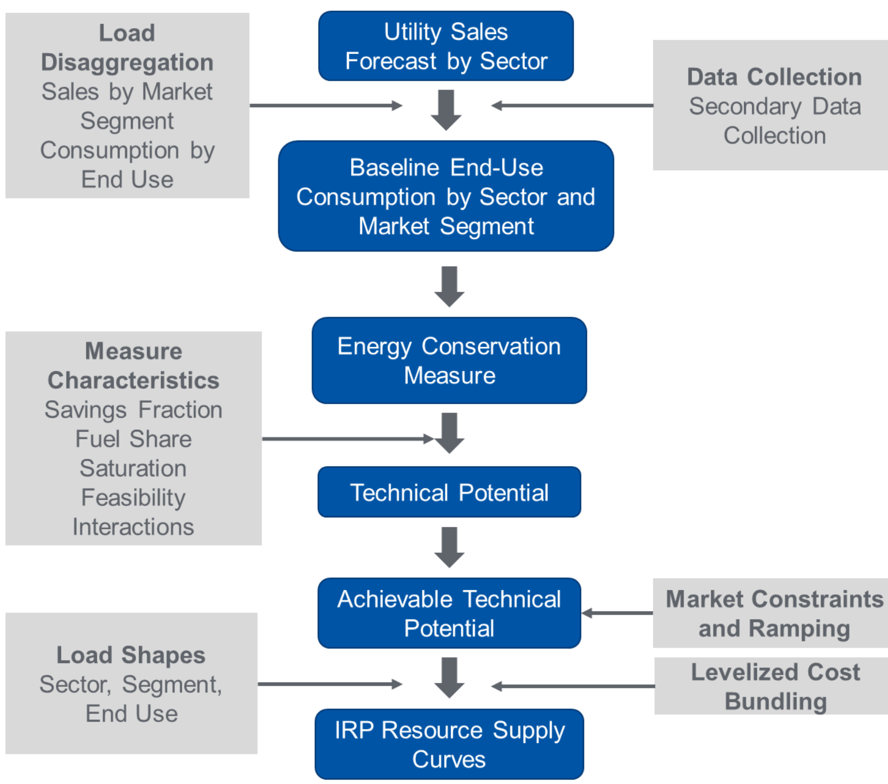
For the bottom-up component, Cadmus estimated natural gas consumptions for each major building end use and applied potential technical impacts of various ECMs to each end use. This bottom-up analysis includes assumptions about end-use equipment saturations, fuel shares, ECM technical feasibility, ECM cost, and engineering estimates of ECM UEC and UES.

For the industrial sector, Cadmus calculated technical potential as a percentage reduction to the baseline industrial forecast. We first estimated baseline end-use loads for each industrial segment, then calculated the potential using estimates of each measures' end-use percentage savings.

When characterizing measure and end-use consumptions, Cadmus used *2021 Power Plan* data (whenever possible) for weather-sensitive measures to account for climate change.[10] Next, we calibrated annual changes in residential and commercial heating end-use consumptions with PSE's climate impacts within annual load forecasts to reflect the effects of climate change on CPA estimates.

A detailed description of the methodology can be found in *Chapter 4. Energy Efficiency Methodology Details*.

Figure 4. Conservation Potential Assessment Methodology



10 Cadmus applied climate change adjustment factors based on the Council's data (TMY to projected FMY) to non-Council weather-sensitive RTF and PSE business case measures.

In the final step, Cadmus developed energy efficiency supply curves so that PSE's IRP portfolio optimization model could identify the amount of cost-effectiveness for energy efficiency. The portfolio optimization model required monthly forecasts of natural gas energy efficiency potential. To produce those monthly forecasts, Cadmus applied monthly end-use load profiles (converted from hourly profiles) to annual estimates of achievable technical potential for each measure. These profiles are generally similar to the shapes the Council used in its draft *2021 Power Plan* supply curves and as the RTF used in its UES measure workbooks.

Considerations and Limitations

This study is intended to support PSE's program planning by providing insights into which measures can be offered in future programs as well as informing the program targets. Several considerations about the design of this potential study may cause future program plans to differ from study results:

- This potential study uses broad assumptions about the adoption of energy efficiency measures. Program design, however, requires a more detailed examination of historical participation and incentive levels on a measure-by-measure basis. This study can inform planning for measures PSE has not historically offered or can help PSE to focus program design on areas with remaining potential identified in this study.
- This potential study cannot predict market changes over time. Even though it accounts for changes in codes and standards as they are enacted today, the study cannot predict future changes in policies, pending codes and standards, and which new technologies may become commercially available. PSE programs are not static and have the flexibility to address changes in the marketplace, whereas the potential study estimates the energy efficiency potential using information collected at a single point in time.
- This potential study does not attempt to forecast or otherwise predict future changes in energy efficiency measure costs. The study includes PSE program measure business cases, Council data, and RTF incremental energy efficiency measure costs, including for equipment, labor, and operations and maintenance (O&M), but it does not attempt to forecast changes to these costs during the course of the study. For example, changes in incremental costs may impact some emerging technologies, which may then impact both the speed of adoption and the levelized cost of that measure (impacting the IRP levelized cost bundles).
- This potential study does not consider program implementation barriers. Although it includes a robust, comprehensive set of efficiency measures, it does not examine if these measures can be delivered through incentive programs or what incentive rate is appropriate. Many programs require strong trade ally networks or must overcome market barriers to succeed.

Acknowledging the fact that these considerations and limitations have an impact on the CPA, it is also worth noting that "RCW 80.28.380 Gas Companies—Conservation Targets"[11] requires PSE to complete and update a CPA every two years. PSE can address some of these considerations over time and mitigate

[11] Revised Code of Washington. Accessed 2022. "RCW 80.28.380 Gas Companies—Conservation Targets." https://app.leg.wa.gov/RCW/default.aspx?cite=80.28.380&pdf=true

short- and mid-term uncertainties by continually revising CPA assumptions to reflect changes in the market.

Energy Efficiency Potential - Results

Table 4 shows the 2050 forecasted baseline natural gas sales and potential by sector.[12] Cadmus' analysis indicates that 232 MMTherm of technically feasible natural gas energy efficiency potential will be available by 2050, the end of the 27-year planning horizon, which translates to an achievable technical potential of 165 MMTherm for residential, commercial, and industrial sectors combined. Should all this achievable technical potential prove cost-effective and realizable, it will result in an 18% reduction in 2050 forecasted retail sales.

Table 4. Natural Gas 27-Year Cumulative Energy Efficiency Potential

Sector	2050 Baseline Sales (MMTherm)	Achievable Technical Potential	
		MMTherm	Percentage of Baseline Sales
Residential	617	111	18%
Commercial	293	51	18%
Industrial	18	3	18%
Total	**928**	**165**	**18%**

Figure 5 shows each sector's relative share of the overall natural gas energy efficiency achievable technical potential. The residential sector accounts for roughly 67% of the total natural gas energy efficiency achievable technical potential, followed by the commercial (31%) and industrial (2%) sectors.

Figure 5. 27-Year Achievable Technical Potential by Sector

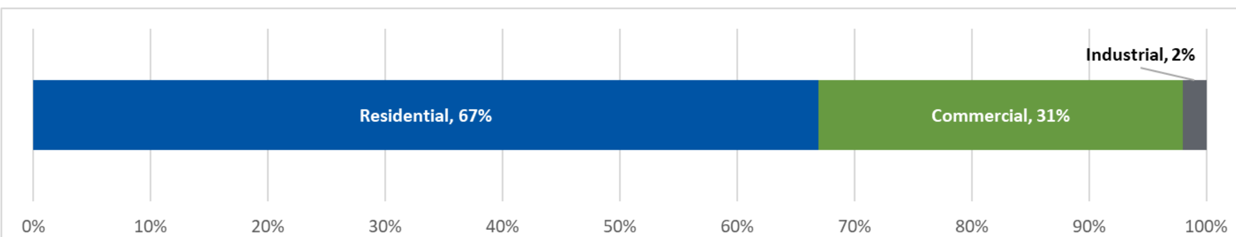


Figure 6 shows the relationship between each sector's cumulative (through 2050) natural gas energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[13] For example, approximately 124 MMTherms of achievable technical potential exists, at a cost of less than $3.00 per therm.

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12 These savings derive from forecasts of future consumption, absent any utility program activities. Note that consumption forecasts account for the savings PSE has acquired in the past, but the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

13 In calculating the levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This means that some measures will have a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 6. Natural Gas 27-Year Cumulative Energy Efficiency Supply Curve by Sector

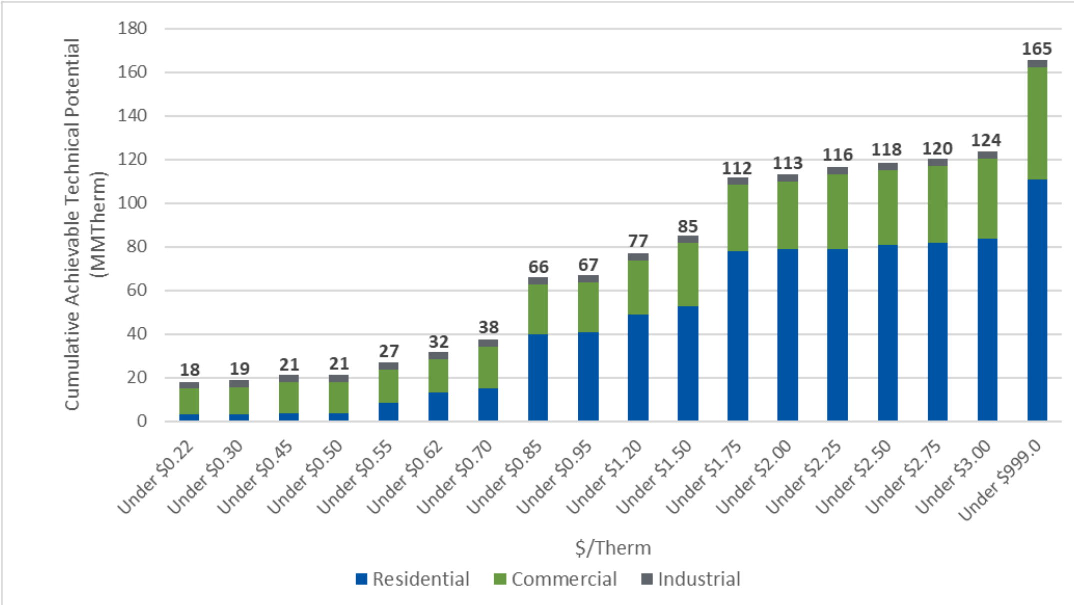


Figure 7 shows the relationship between cumulative natural gas energy efficiency achievable technical potential (through 2050) for discretionary and lost opportunity resources and the corresponding cost of conserved electricity.

Figure 7. Natural Gas 27-Year Cumulative Energy Efficiency Supply Curve by Type of Resource (Discretionary vs. Lost Opportunity)

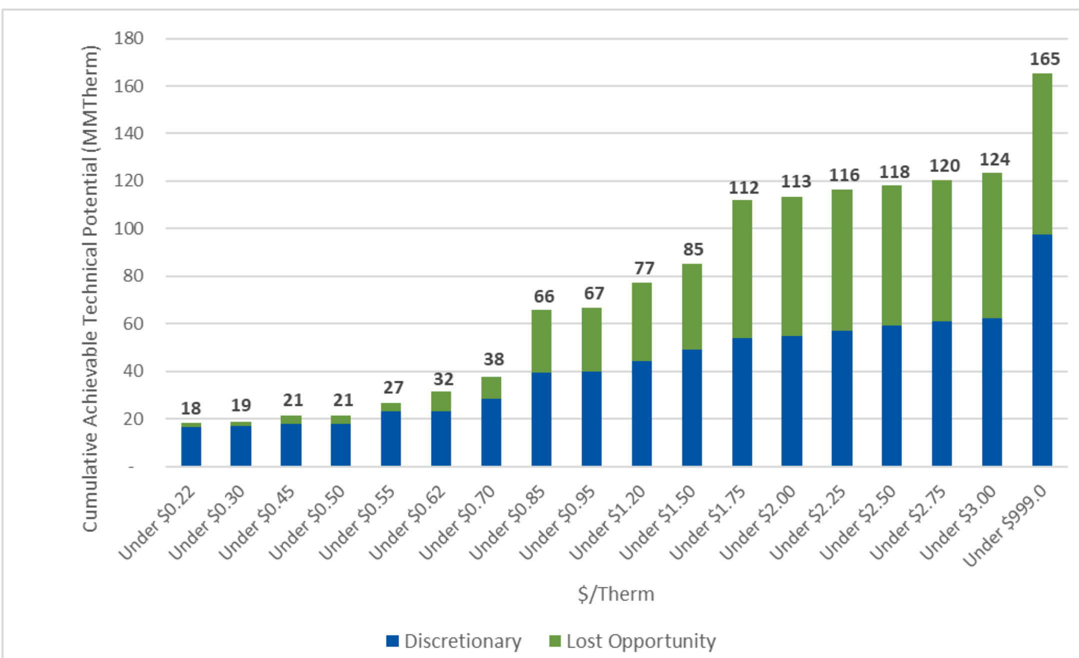
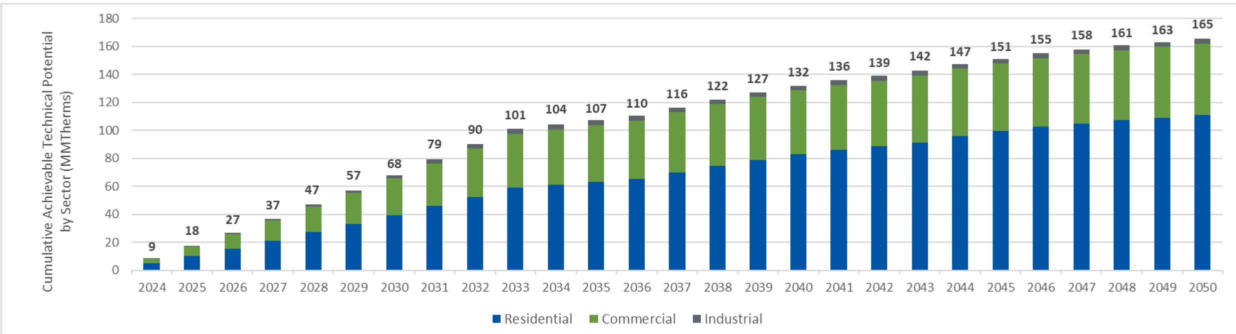


Figure 8 illustrates the cumulative achievable technical potential available annually in each sector. As shown in the figure, more savings are achieved in the first 10 years of the study (2024 through 2033) than in the remaining years. For this study, Cadmus assumed that discretionary measure potential savings are acquired in the first 10 years (for a selected set of measures that are retrofit in existing homes and businesses). The 10-year acceleration of discretionary resources will lead to the change in slope after 2033, at which point lost opportunity resources offer most of the remaining potential.

Figure 8. Natural Gas Energy Efficiency Potential Forecast



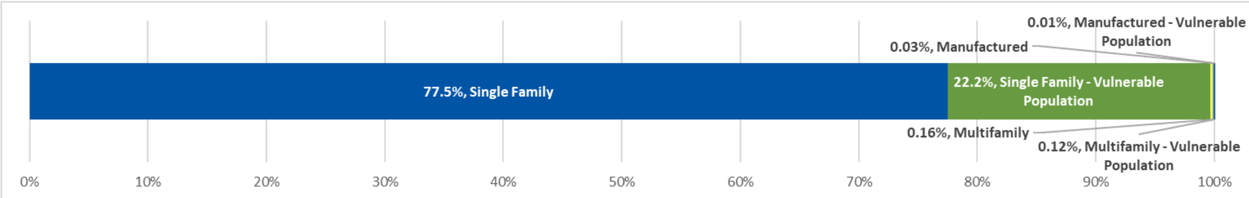
Energy Efficiency Potential - Residential Sector

By 2050, residential customers in PSE's service territory will likely account for approximately 66% of forecasted natural gas retail sales in three sectors (residential, commercial, and industrial). The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (such as boilers, furnaces, cooking ovens, and clothes dryers), improvements to building shells (including insulation, windows, and air sealing), and increases in domestic hot water efficiency (such as tankless water heaters).

As shown in Figure 9, single-family homes represent 99.7% of the total achievable technical residential natural gas potential, leaving only 0.3% from multifamily and manufactured homes, all including vulnerable populations.

Each home type's proportion of baseline sales is the primary driver of these results, but other factors such as heating fuel sources and equipment saturations are important for determining potential. For example, a very small percentage of manufactured homes use natural gas heat compared to other home types, which diminishes their relative share of the potential. Manufactured homes also tend to be smaller than detached single-family homes, and they experience lower per-customer energy; therefore, the same measure may save less in a manufactured home than in a single-family home.

Figure 9. Residential Natural Gas Achievable Technical Potential by Segment



Space heating end uses represent the largest portion (63%) of achievable technical potential, followed by water heating (36%) and dryer and cooking (0.4% each) end uses (Figure 10). The total achievable technical potential for residential increases to 111 MMTherms over the study horizon (Figure 11).

Figure 10. Residential Natural Gas Achievable Technical Potential by End Use

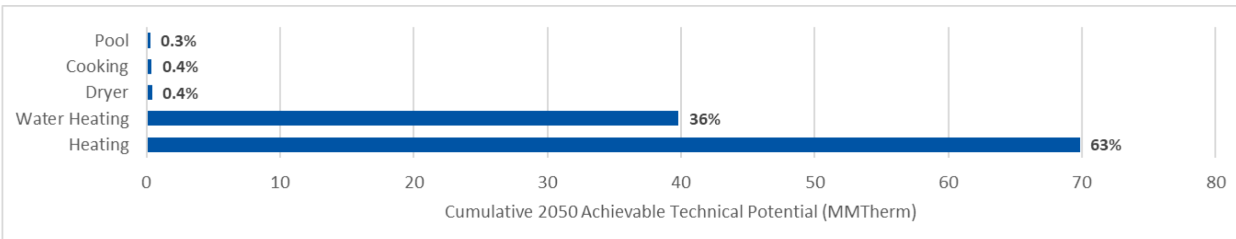


Figure 11. Residential Natural Gas Achievable Technical Potential Forecast by End Use

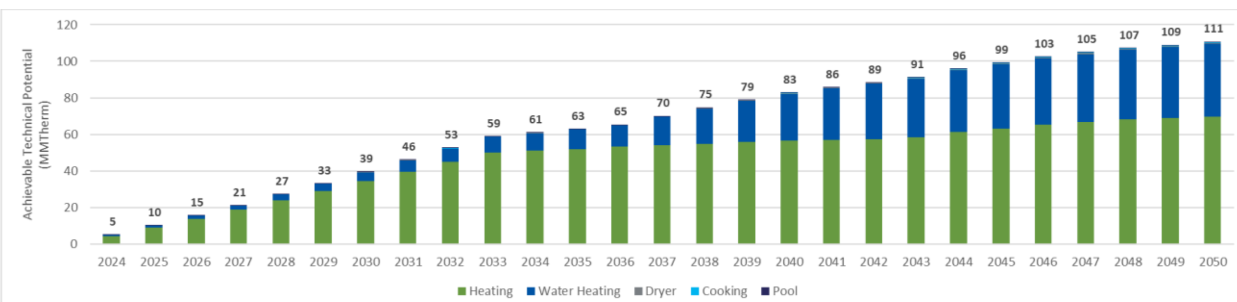


Table 5 lists the top 10 residential natural gas energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for roughly 98 MMTherms, or approximately 89% of the total residential natural gas achievable technical potential. Premium efficiency furnaces represent the measure with the highest energy savings and all of the top 10 measures, except tankless water heaters, reduce natural gas heating loads: this includes an equipment measure (premium efficiency furnace) and retrofit measures (smart thermostat, insulation, and windows). This list represents both economic and non-economic measures.

Table 5. Top Residential Natural Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MMTherm)	Cumulative 27-Year Achievable Technical Potential (MMTherm)
Furnace - Premium Efficiency	8.6	26.3
Water Heater - ENERGY STAR Tankless	2.6	25.3
Smart Thermostat	10.6	11.3
Integrated Space and Water Heating	1.3	9.6
Duct Sealing	6.2	6.2
Window - Storm Window	5.2	5.2
Insulation - Attic	5.1	5.1
Insulation - Wall	4.8	4.8
Windows	2.7	2.8
Duct Insulation	1.8	1.8

In addition to estimating potential for each residential housing segment, Cadmus estimated potential for vulnerable population customers within PSE's natural gas service territory. Cadmus segmented PSE residential accounts (single family, multifamily, and manufactured) for vulnerable populations by county. As an approximation, Cadmus also used PSE 2021 RCS data to inform equipment saturations and fuel shares for vulnerable populations (based on income criterion with households having less than $49,000 gross annual income). Table 6 provides the percentage of vulnerable population customers in each county of PSE's natural gas service territory.

Table 6. Percentage of Vulnerable Population Customers in Each County

County	Percentage of Vulnerable Population Customers
King County	22%
Kittitas County	11%
Lewis County	51%
Pierce County	42%
Snohomish County	19%
Thurston County	36%

Cadmus derived UES estimates specifically for vulnerable population customers using low-income–specific measures from PSE's business cases:

- Weatherization: Attic, duct, floor, and wall insulation; air and duct sealing; and single-, double-, and triple pane windows
- Water heating: water heater pipe insulation, integrated space and water heating system
- Smart thermostats

Cadmus also apportioned savings from non-low-income–specific PSE business case measures to vulnerable population customers for other measures, including home energy reports, windows (single-, double-, and triple-pane with different U factors) and tub spouts.

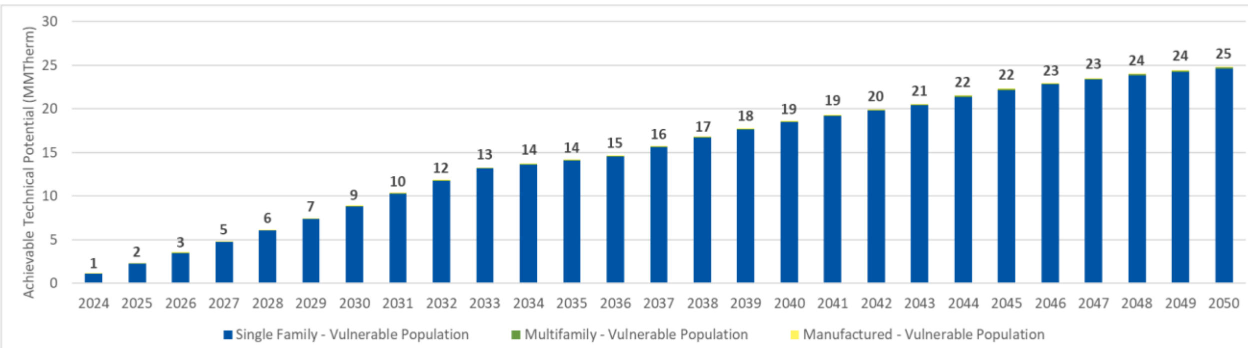
Table 7 shows the cumulative 10-year (through 2033) and 27-year (through 2050) achievable technical potential for PSE's vulnerable population customers by housing segment.

Table 7. Residential Vulnerable Population Customer Potential – Natural Gas

Segment	Cumulative 10-Year Achievable Technical Potential (MMTherm)	Cumulative 27-year Achievable Technical Potential (MMTherm)
Single Family - Vulnerable Population	13.170	24.603
Multifamily - Vulnerable Population	0.075	0.132
Manufactured - Vulnerable Population	0.005	0.008
Total	**13.2**	**24.7**

Figure 12 provides the cumulative residential vulnerable population natural gas achievable technical potential forecast by housing segment. The potentials shown above in Figure 11 include the vulnerable population customer potential shown in Figure 12.

Figure 12. Residential Achievable Technical Potential Forecast for Vulnerable Populations

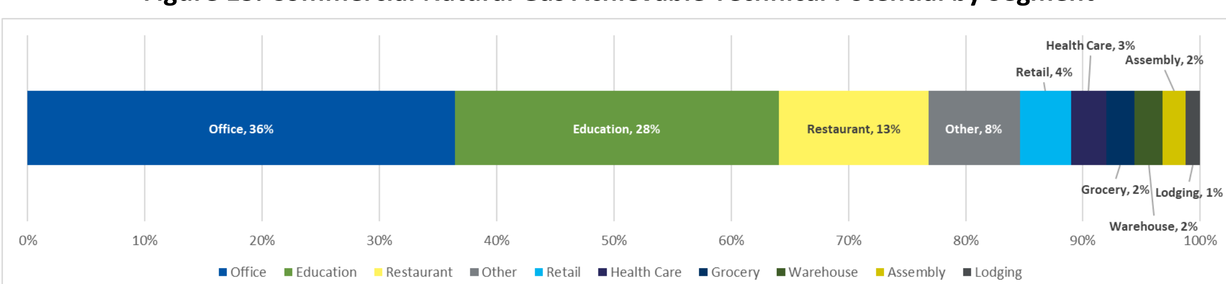


Energy Efficiency Potential - Commercial Sector

Based on the energy efficiency measure resources used in this assessment, natural gas energy efficiency achievable technical potential in the commercial sector will likely be 51 MMTherms over 27 years, which is approximately an 18% reduction in forecasted 2050 commercial sales.

As shown in Figure 13, the office, education, and restaurant segments represent 36%, 28%, and 13%, respectively, of the total commercial achievable technical potential. The "other" segment, which includes customers who do not fit into any of the other categories and customers with insufficient information for classification, represents 8% of commercial achievable technical potential. Each of the remaining segments has less than 5% of commercial achievable technical potential.

Figure 13. Commercial Natural Gas Achievable Technical Potential by Segment



As shown in Figure 14, the heating end use represents the largest portion of achievable technical potential in the commercial sector (75%), followed by the cooking (16%) and water heat (9%) end uses. Figure 15 presents the annual cumulative natural gas commercial achievable technical potential by end use.

Figure 14. Commercial Natural Gas Achievable Technical Potential by End Use

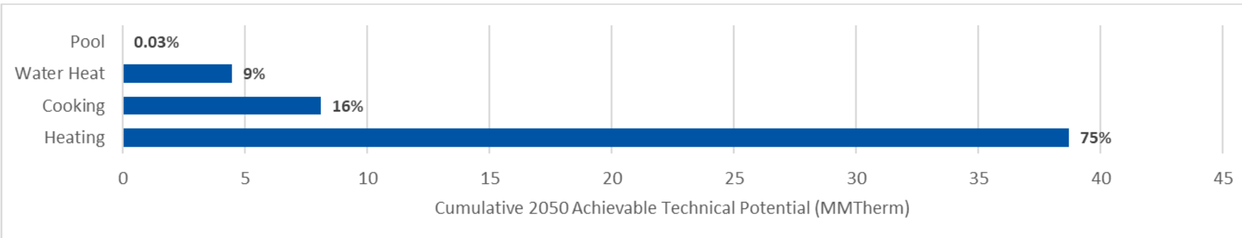


Figure 15. Commercial Natural Gas Achievable Technical Potential Forecast

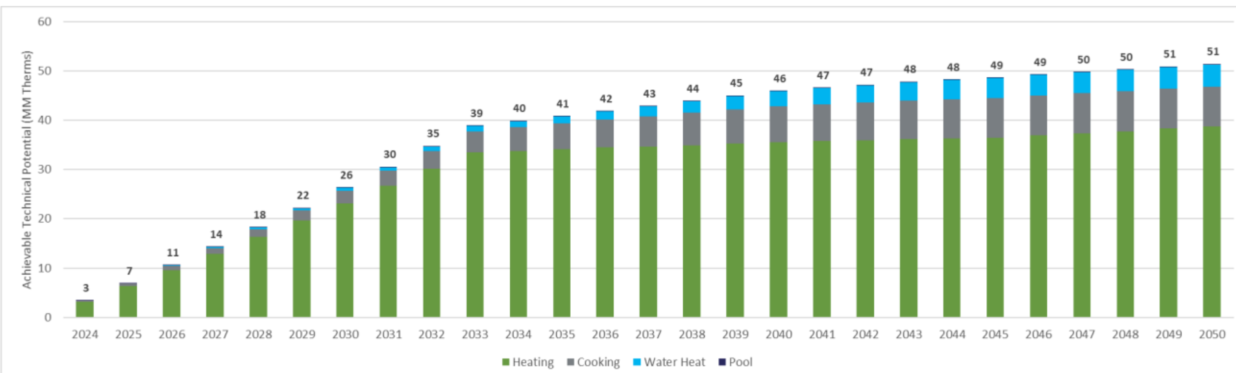


Table 8 lists the top 10 commercial natural gas energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for 38 MMTherms, or approximately 74% of the total natural gas commercial achievable technical potential.

Table 8. Top Commercial Natural Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MMTherm)	Cumulative 27-Year Achievable Technical Potential (MMTherm)
Re-Commissioning	7.6	7.6
Energy Management System	5.6	5.6
Space Heat - Natural Gas Furnace	1.5	4.3
Window - Secondary Glazing	4.2	4.2
Weatherization - Attic/Roof Insulation	3.3	3.3
Pipe Insulation - Space Heat	3.0	3.0
Water Heat LE 55 Gallon	0.3	3.0
Space Heat - Natural Gas Boiler	1.2	2.8
Kitchen Hood - Demand Controlled Ventilation	2.0	2.0
Fryer	0.8	1.8

Energy Efficiency Potential - Industrial Sector

Since electricity is the most commonly used energy source in industrial processes, the industrial sector represents a small portion of natural gas baseline sales and potential. Across all industries assessed, achievable technical potential is approximately 3 MMTherms over the 27-year planning horizon, corresponding to an 18% reduction of forecasted 2050 industrial natural gas retail sales.

Figure 16 shows 27-year natural gas industrial achievable technical potential by segment. Miscellaneous manufacturing represents 48% of the total 27-year natural gas industrial achievable technical potential followed by the other food (15%), transportation equipment (13%), metal fabrication (7%). and chemical (6%) industries. No other industry represents more than 5% of industrial natural gas achievable technical potential.

Figure 16. Industrial Natural Gas Achievable Technical Potential Forecast

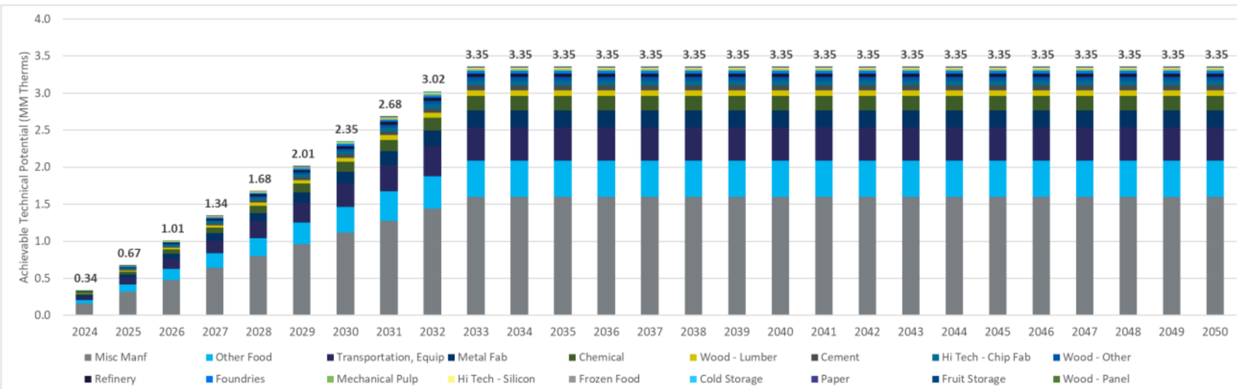


Table 9 presents natural gas cumulative 27-year achievable technical potential for the top 10 measures in the industrial sectors. The top 10 measures combined equal approximately 2.5 MMTherms of achievable technical potential, or roughly 74% of the industrial total.

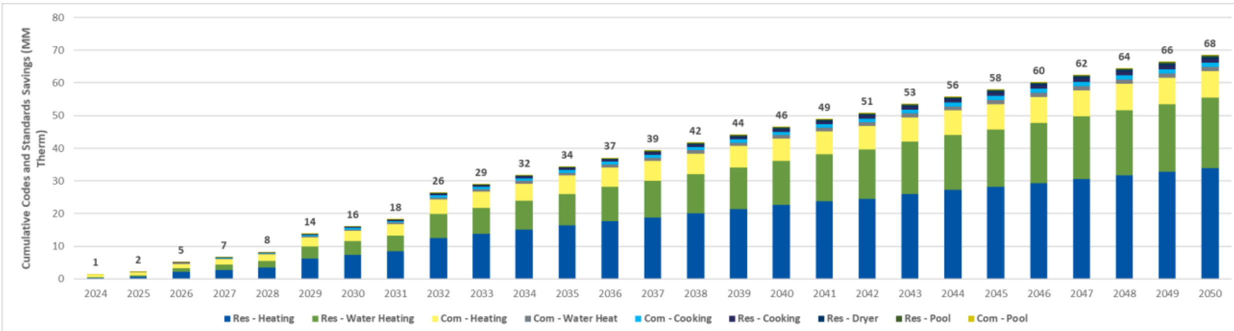
Table 9. Top Industrial Natural Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MMTherm)	Cumulative 27-Year Achievable Technical Potential (MMTherm)
Waste Heat from Hot Flue Gases to Preheat	0.37	0.37
Improve Combustion Control Capability and Air Flow	0.36	0.36
Process Improvements to Reduce Energy Requirements	0.32	0.32
Install or Repair Insulation on Condensate Lines and Optimize Condensate	0.31	0.31
Heat Recovery and Waste Heat for Process	0.31	0.31
Optimize Heating System to Improve Burner Efficiency and Reduce Energy Requirements and Heat Treatment Process	0.18	0.18
Equipment Upgrade - Boiler Replacement	0.17	0.17
Thermal Systems Reduce Infiltration; Isolate Hot or Cold Equipment	0.17	0.17
Equipment Upgrade - Replace Existing HVAC Unit with High-Efficiency Model	0.15	0.15
Analyze Flue Gas for Proper Air/Fuel Ratio	0.15	0.15

Impacts of Codes and Standards

Figure 17 presents naturally occurring savings in PSE's service territory from the WSEC equipment standards and federal equipment standards, which is equal to 68 MMTherms in 2050.

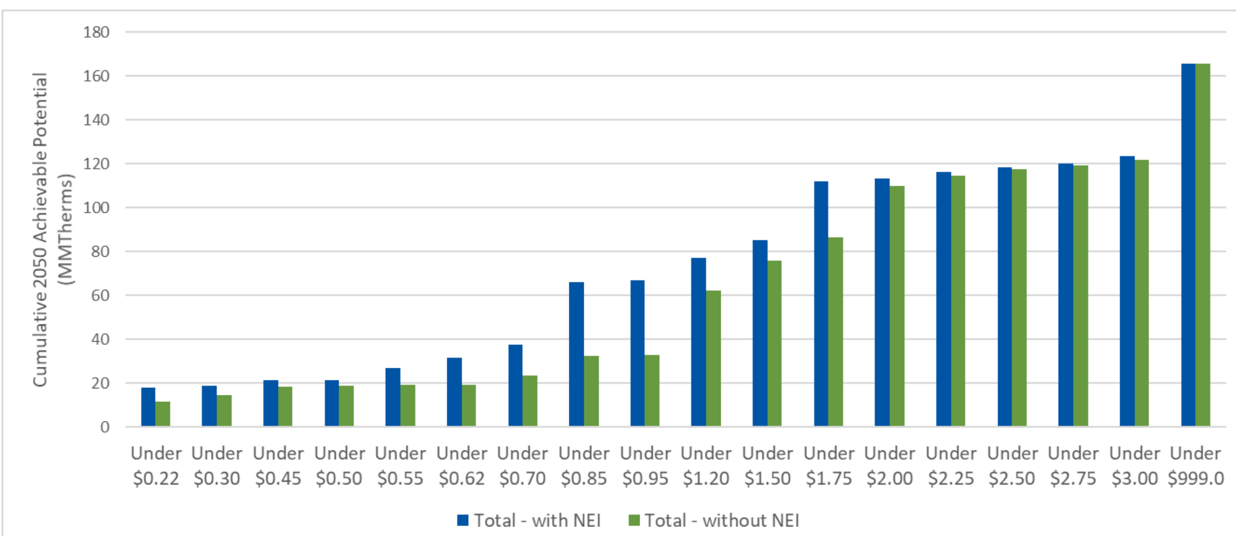
Figure 17. Natural Gas Codes and Standards Potential Forecast



Non-Energy Impacts

In addition to the Council and RTF measures with NEIs (limited to water savings, O&M, and lifetime replacement), this CPA incorporates additional NEI data to inform the IRP levelized cost bundles. Cadmus based the NEI data on PSE's recent program evaluation that included an assessment of program measure NEIs. Figure 18 shows a comparison of the cumulative 2050 achievable technical potential with and without the inclusion of these additional NEI data. The figure shows an increase in potential within the relatively lower-cost bundles with less of an impact in the high-cost bundles.

Figure 18. Non-Energy Impacts on Levelized Cost, Cumulative 2050 Achievable Technical Potential



Chapter 2. Energy Efficiency Potential for Small Transport Customer Sector

Scope of the Analysis

Per the Climate Commitment Act, PSE is including its small transport customer sector into this CPA as a compliance requirement. Small transport is a class of customers who had an average of less than 25,000 tonnes of annual carbon dioxide emission per Mscf of their natural gas consumption in 2015 through 2019. There were 309 small commercial and industrial (C&I) sites in PSE's service territory in this customer class.

Energy Efficiency Potential

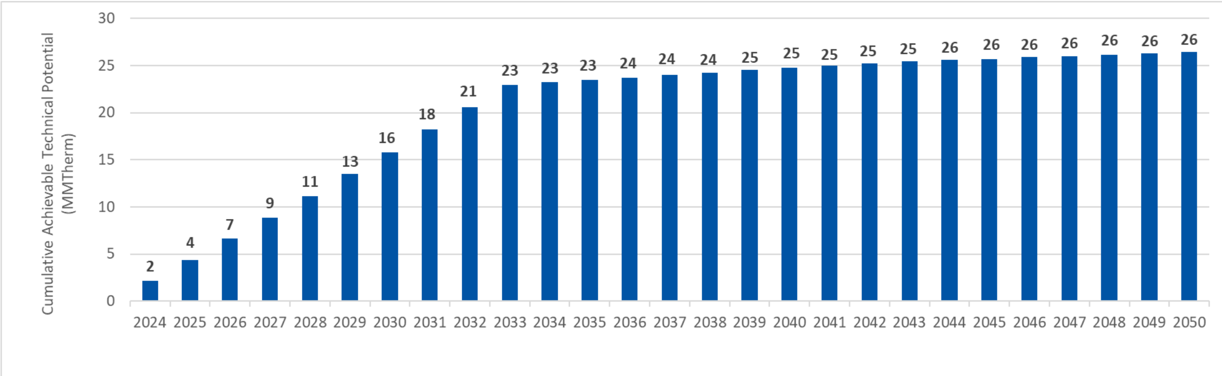
Cadmus estimated the energy efficiency potential for small transport customers using a methodology similar to the one used for standard C&I customers. The segments we included in the potential calculations are shown below. We excluded the small and medium office; small, medium, and large retail; mini-mart; university; and kraft pulp segments, as there were no small transport customer in these segments in PSE's service territory.

SMALL TRANSPORT - COMMERCIAL	**SMALL TRANSPORT - INDUSTRIAL**
ELEVEN SEGMENTS Large Office, Extra Large Retail, School K–12, Warehouse, Supermarket, Restaurant, Lodging, Hospital, Residential Care, Assembly, Other	**EIGHTEEN SEGMENTS** Mechanical Pulp, Paper, Foundries, Food – Frozen, Food – Other, Wood – Lumber, Wood – Panel, Wood – Other, Cement, Hi Tech – Chip Fabrication, Hi Tech – Silicon, Metal Fabrication, Transportation Equipment, Refinery, Cold Storage, Fruit Storage, Chemical, Miscellaneous Manufacturing

Across all modeled segments, achievable technical potential is approximately 26 MMTherms over the 27-year planning horizon, corresponding to a 15% reduction of forecasted 2050 small transport customer natural gas retail sales.

Figure 19 shows 27-year natural gas achievable technical potential for small transport customers. Cadmus assumed that all discretionary resources will be acquired on a 10-year schedule between 2024 and 2033. The 10-year acceleration of discretionary resources will lead to the change in slope after 2033, at which point lost opportunity resources offer the only remaining potential.

Figure 19. Natural Gas Achievable Technical Potential Forecast for Small Transport Customers



As shown in Figure 20, the boiler end use represents the largest portion of achievable technical potential in the small transport sector (34%), followed by process (26%) and heating (20%). All other end uses have less than a 10% share of the achievable technical potential.

Figure 20. Natural Gas Achievable Technical Potential by End Use for Small Transport Customers

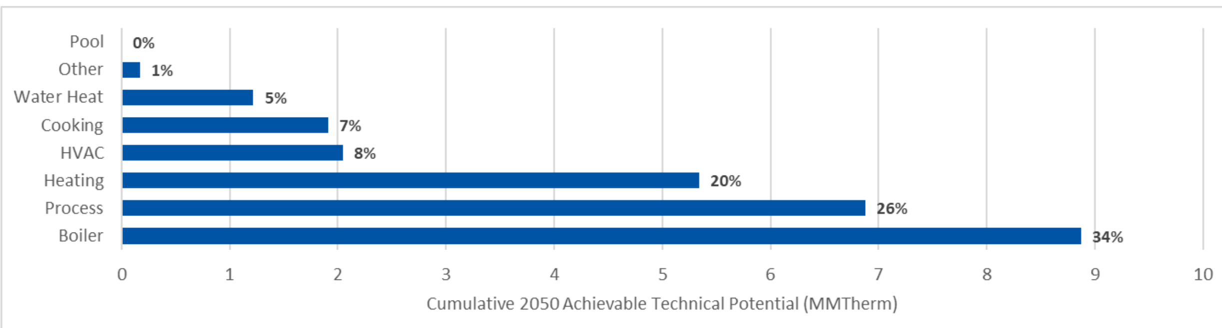


Figure 21 shows the relationship between the small transport sector's cumulative (through 2050) natural gas achievable technical potential and the corresponding cost of conserved electricity. For example, approximately 26 MMTherms of achievable technical potential exists at a cost of less than $3.00 per therm.

Figure 21. Natural Gas 27-Year Cumulative Energy Efficiency Supply Curve for Small Transport Customers

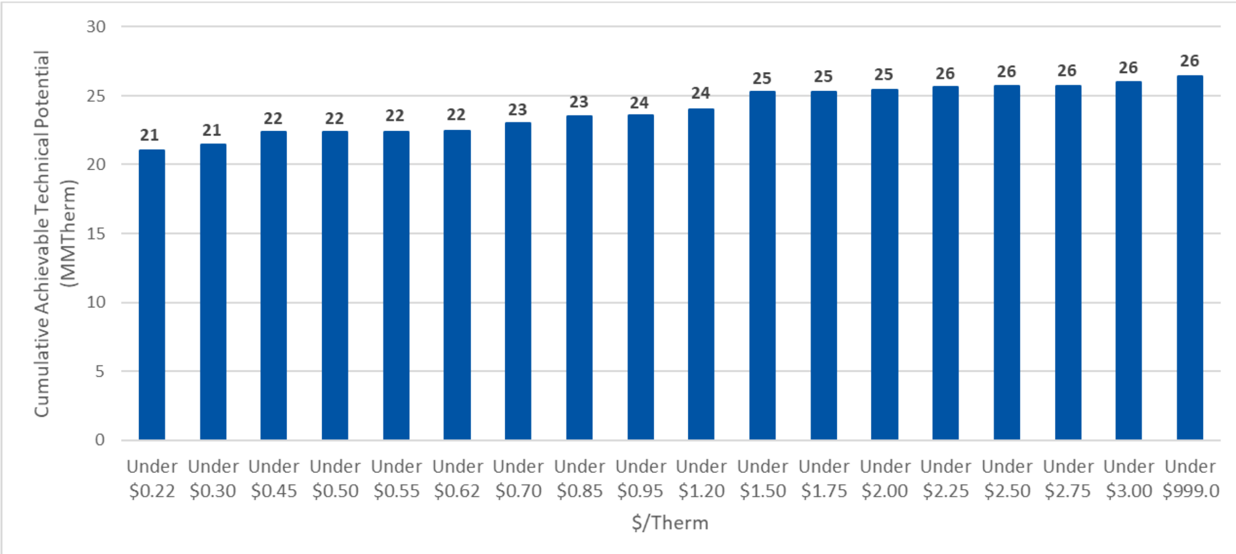


Table 10 presents natural gas cumulative 27-year achievable technical potential for the top 10 measures for small transport customers ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for 14 MMTherms, or approximately 52% of the total natural gas achievable technical potential for small transport customers.

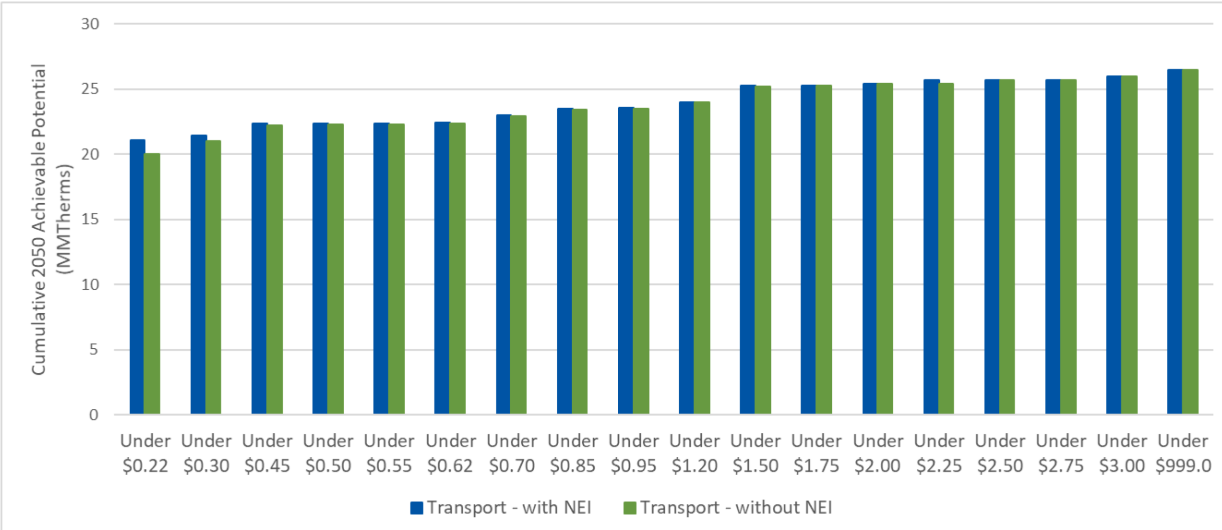
Table 10. Top Natural Gas Measures for Small Transport Customers

Measure Name	Cumulative 10-Year Achievable Technical Potential (MMTherm)	Cumulative 27-Year Achievable Technical Potential (MMTherm)
Waste Heat from Hot Flue Gases to Preheat	2.0	2.0
Improve Combustion Control Capability and Air Flow	1.9	1.9
Process Improvements to Reduce Energy Requirements	1.7	1.7
Install or Repair Insulation on Condensate Lines and Optimize Condensate	1.7	1.7
Heat Recovery and Waste Heat for Process	1.7	1.7
Energy Management System	1.1	1.1
Optimize Heating System to Improve Burner Efficiency and Reduce Energy Requirements and Heat Treatment Process	0.9	0.9
Re-Commissioning	0.9	0.9
Equipment Upgrade - Boiler Replacement	0.9	0.9
Thermal Systems Reduce Infiltration; Isolate Hot or Cold Equipment	0.9	0.9

Non-Energy Impacts

Similar to the C&I sectors, Cadmus incorporated additional NEI data that was based on PSE's recent program evaluation to inform the IRP levelized cost bundles for the small transport customer sector. Figure 22 shows a comparison of the cumulative 2050 achievable technical potential with and without the inclusion of these additional NEI data. Overall, the impact of NEIs was less pronounced in transport sector compared to all other three sectors combined (as shown in Figure 18). As the figure shows, there is an increase in potential within the few lowest-cost bundles with less of an impact in the high-cost bundles.

Figure 22. Non-Energy Impacts on Levelized Cost, Cumulative 2050 Achievable Technical Potential



Chapter 3. Natural Gas-to-Electric Potential Assessment

Public policies that are intended to help transition energy product and end uses away from fossil fuels are affecting electric and natural gas utilities across the country. The Climate Commitment Act[14] is for capping and reducing greenhouse gas emissions from Washington's largest emitting sources and industries with the limits 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels by 2050.

To address the impact of natural gas–to-electric conversion on PSE's system, Cadmus estimated the load impacts as well as the associated impacts of energy efficiency and demand response potential. To determine the load impacts, we evaluated three supply curve alternatives for PSE's IRP (hybrid heat pump – market, hybrid heat pump – policy, and full electrification – policy). To determine the impacts on energy efficiency and demand response potentials, we evaluated two policy supply curve alternatives (hybrid heat pump – policy and full electrification – policy). These supply curve alternatives (scenarios) were based on differences in heat pump technology as well as policy and market adoption criteria. For the residential sector, Cadmus conducted the natural gas–to-electric conversion potential analysis under three different scenarios:

HYBRID HEAT PUMP – MARKET

Cadmus analyzed the effects of a conversion from natural gas heating equipment (such as a natural gas furnace and ductless natural gas heating) to a heat pump (such as a ductless and ducted ASHP), while keeping the natural gas heating equipment as the backup. We obtained the market adoption rates for this scenario from the customer survey. The data will inform PSE's IRP, where technologies will be selected based on their cost-effectiveness in the natural gas portfolio model, where the customer adoption is limited by customer willingness to convert to electric equipment.

HYBRID HEAT PUMP – POLICY

Cadmus analyzed the effects of a conversion from natural gas heating equipment to a heat pump while keeping the natural gas heating equipment as the backup but, unlike in the previous scenario, we adjusted the market adoption rate to a maximum where 100% of applicable residential applications have a hybrid heat pump or ductless system with natural gas backup. This scenario represents a policy change where all residential customers are required to convert to a hybrid heat pump. Under this scenario the IRP will select all converted technologies regardless of costs, where the end-of-life replacement of natural gas equipment with hybrid heat pumps will reach 100% annual adoption within the study horizon based on future policy requirements.

FULL ELECTRIFICATION – POLICY

Cadmus analyzed the effects of a conversion from natural gas heating equipment to a heat pump without keeping the natural gas heating equipment and assumed full adoption (where the market adaption rate equals to 100%) to represent a policy change banning natural gas usage and forcing all customers to convert to heat pumps. Under this scenario the IRP will select all converted technologies regardless of costs, where the end-of-life replacement of natural gas equipment with electric heat pumps (with no natural gas backup) will reach 100% annual adoption within the study horizon based on future policy requirements.

All commercial and industrial customers have the same adoption across all scenarios.

[14] Washington State Legislature. 2021. *SB 5126 - 2021-22 Concerning the Washington climate commitment act.* https://app.leg.wa.gov/billsummary?billnumber=5126&year=2021

As part of this CPA, Cadmus estimated per-unit impacts—including reductions in natural gas usage and increased electric energy and peak demand—and customer costs for the full suite of electrification measures including space and water heating systems, stoves and cooktops, and clothes dryers for existing customers and new construction in the residential and commercial sectors.

Cadmus used data from PSE customer database, the PSE RCS, the CBSA, and other sources to calculate these potential impacts. Additionally, we conducted primary research by conducting a residential customer survey to determine the appropriate heat pump technologies (such as ductless heat pump partial- and full-load conversion, heat pumps with no supplement heating, and hybrid heat pumps) that customers would likely install if converting from a non-electric fuel. Furthermore, Cadmus conducted contractor and builder interviews to determine heat pump conversion costs (for hybrid, ductless, and ducted heat pumps) including any additional costs to convert to electric from non-electric equipment, such as electrical panel or wiring upgrades, duct reconfiguration, and added labor costs.

Table 11 details the natural gas–to-electric equipment being replaced and converted under the full electrification policy scenario.

Table 11. Full Replacement Policy Scenario – Natural Gas–to-Electric Equipment

Sector	Electric – Converted To	Natural Gas – Converted From
Residential	Ductless Heat Pump (DHP) - Whole Home Central	Furnace - Full Replacement
	Air-Source Heat Pump (ASHP) - Whole Home	Furnace - Full Replacement without Existing AC
	ASHP - Whole Home	Furnace - Full Replacement with Existing AC
	DHP - Whole Home Zonal	Boiler - Full Replacement
	DHP - Whole Home Zonal	Natural Gas Wall Unit - Full Replacement
	Cooking Oven (Electric)	Cooking Oven (Natural Gas)
	Cooking Range (Electric)	Cooking Range (Natural Gas)
	Dryer (Electric) - Non-Heat Pump	Dryer (Natural Gas)
	Water Heat ≤55 Gal	Water Heat (Natural Gas)
	Water Heat >55 Gal	Water Heat (Natural Gas)
Commercial	ASHP/Variable Refrigerant Flow/DHP	Natural Gas Space Heat - Full Replacement
	Cooking (Electric)	Cooking (Natural Gas)
	Water Heat ≤55 Gal	Water Heat (Natural Gas)
	Water Heat >55 Gal	Water Heat (Natural Gas)
Industrial	Target Reduction Conversion of Natural Gas Load 30% Reduction	

For both the hybrid market and policy scenarios, Table 12 shows the natural gas-to-electric equipment being replaced and converted. Under these scenarios, the converted residential space heat equipment is hybrid and partial-load replacement heat pump systems that still rely on natural gas backup heating during cold temperatures.[15] Cadmus estimated 88% electric consumption and 12% natural gas consumption based on building simulations[16] using Seattle-area weather data.

Table 12. Hybrid Policy and Market Scenarios – Gas to Electric Equipment

Sector	Electric – Converted To	Natural Gas – Converted From
Residential	DHP with Furnace Backup	Furnace - Partial Replacement
	Hybrid ASHP with Furnace Backup without Existing AC	Furnace - Partial Replacement without Existing AC
	Hybrid ASHP with Furnace Backup with Existing AC	Furnace - Partial Replacement with Existing AC
	DHP with Boiler Backup	Boiler - Partial Replacement
	DHP with Natural Gas Wall Unit Backup	Natural Gas Wall Unit - Partial Replacement
	Cooking Oven (Electric)	Cooking Oven (Natural Gas)
	Cooking Range (Electric)	Cooking Range (Natural Gas)
	Dryer (Electric) - Non-Heat Pump	Dryer (Natural Gas)
	Water Heat ≤55 Gal	Water Heat (Natural Gas)
	Water Heat >55 Gal	Water Heat (Natural Gas)
Commercial	ASHP/Variable Refrigerant Flow/DHP	Natural Gas Space Heat - Full Replacement
	Cooking (Electric)	Cooking (Natural Gas)
	Water Heat ≤55 Gal	Water Heat (Natural Gas)
	Water Heat >55 Gal	Water Heat (Natural Gas)
Industrial	Target Reduction Conversion of Natural Gas Load 30% Reduction	

Methodology

Cadmus calculated the energy, peak demand, and cost impacts of converting natural gas–to-electric equipment within PSE's natural gas service territory. Because PSE's natural gas service territory includes not only PSE electric customers but also electric customers of Seattle City Light, Snohomish County Public Utility District, Tacoma Power, and Lewis County Public Utility District, PSE natural gas–to-electric customer conversion end uses will inevitably affect these other utilities' electric systems. However, for the purpose of this IRP and this natural gas–to-electric potential assessment, our electric energy and peak demand potential estimates only apply to PSE's electric service territory and exclude the impacts on other electric utilities.

We applied different analytical approaches for the residential and commercial sectors than for the industrial sector. For the residential and commercial sectors, we counted the number of natural gas equipment units in PSE's service area and applied the energy, demand, and cost impacts to these units. In the industrial sector, we calculated the total industrial natural gas load and then converted this load into electric energy and peak demand.

[15] Cadmus assumed a 35-degree auxiliary heat lock-out setpoint based on the 2018 WSEC (R403.1.2 Heat Pump Supplementary Heat).

[16] Cadmus used the National Renewable Energy Laboratory's BEopt™ (Building Energy Optimization Tool) software.

Residential and Commercial Sectors

Cadmus calculated the number of natural gas equipment units and the number of electric equipment units that could be converted in PSE's service area for both existing equipment and new construction. We took PSE's customers counts and forecasts and applied equipment saturation rates and fuel shares in each year of the study horizon (2024 through 2050) plus a base year (2023). We incorporated these data into Cadmus' end-use forecast model, thereby aligning energy efficiency and natural gas–to-electric assumptions and producing alterative base case forecasts.

Cadmus used PSE customer counts and forecasts, residential equipment saturation and fuel share data from PSE's 2021 RCS, commercial equipment saturation data from the 2023 PSE CPA, and the 2019 CBSA to estimate natural gas equipment counts. Cadmus used PSE's current CPA to determine the energy impacts of equipment conversion. To assess the peak demand impacts, Cadmus used PSE's gas to electric IRP high load hour definition to determine the coincident peak impacts. To align with PSE's IRP modeling of gas to electric peak impacts, Cadmus defined each scenario differently rather than following the energy efficiency modeling peak hour definitions. For instance, the hybrid heat pump equipment scenarios assume zero electric peak impact under normal peak conditions (e.g., 28° Fahrenheit or lower) and conversely, there would be no reduction in natural gas peak. Under the full replacement scenario, the converted heat pumps would increase the electric peak load and remove the natural gas peak load. Table 13 lists the data sources we used to analyze conversion impacts in the residential and commercial sectors.

Table 13. Data Sources for the Residential and Commercial Analysis

Analysis Component	Data Sources
Residential, Commercial, and Industrial Customer Counts	2022 PSE customer counts, PSE customer forecasts
Residential Equipment Fuel Shares and Saturations	2021 RCS, NEEA 2017 RBSA
Commercial Equipment Fuel Shares and Saturations	NEEA 2019 CBSA
Residential Electric Equipment Consumption	2023 PSE CPA
Commercial Electric Equipment Consumption	2023 PSE CPA
Residential Electric Equipment Peak Demand	2023 PSE CPA, end-use load shapes
Commercial Electric Equipment Peak Demand	2023 PSE CPA, end-use load shapes
Residential Electric Equipment Costs	2023 PSE CPA, Cadmus' primary market research (contractor interviews)
Commercial Electric Equipment Costs	2023 PSE CPA

Industrial Sector

Cadmus used the 2023 CPA methodology to estimate the new electric industrial load. We calculated the total industrial non-electric space heating load by proportioning industrial customer natural gas sales using data from PSE's 2023 CPA. We calculated potential for the industrial sector by converting a portion (~30%) of natural gas loads based on prior analysis by Cadmus. This is consistent with literature showing that industries with low-temperature and medium-temperature (under 750°F) process heat consumptions represent roughly 33% of the overall usage for electric conversion technologies that are available on the market.[17] Higher-temperature applications are either very costly or are not commercially available on the market.

Cadmus applied the annual reduction to natural gas sales based on prior analysis by Cadmus. We then converted the non-electric MMBtu into electric kilowatt-hours and applied the new electric load on the applicable end-uses for each industry type. It should be noted, however, that the forecast of industrial customer declines from year to year. Therefore, the industrial load analysis applied only to the existing construction conversion scenario.

Market Research

As part of the natural gas–to-electric conversion potential assessment, Cadmus conducted a heat pump market research study and fielded an online customer survey (862 surveys completed by natural gas PSE customers) for measuring the residential sector's willingness to pay for natural gas conversions to heat pumps. We also interviewed contractors and builders (14 interviews completed) in PSE's service territory to determine heat pump (hybrid, ductless, ducted, and other) conversion costs, including any additional costs to convert to electric from non-electric equipment, such as electrical panel or wiring upgrades, duct reconfiguration, and added labor costs. The data we collected through the survey and interviews supported our analysis for determining the adaption rates and conversion costs.

Residential Customer Survey

Cadmus assessed the market demand for natural gas conversions to heat pumps by measuring willingness to pay through an online customer survey. Survey respondents rated their likelihood to purchase a product, answering cascading questions about their willingness to buy at increasingly higher or lower price levels. These data then informed the demand curve for multiple heat pump products (such as hybrid, ductless, ducted, and cold climate). The results from the survey directly informed the potential adoption of these heat pump technologies. Supplemental questions also included the propensity of customer acceptance for converting to electric cooking equipment and electric water heating equipment.

The survey revealed that residential customers are more willing and influenced by incentives to install hybrid heat pump systems with natural gas backup. Figure 23 shows the customer market demand based on heat pump type and incentive level.

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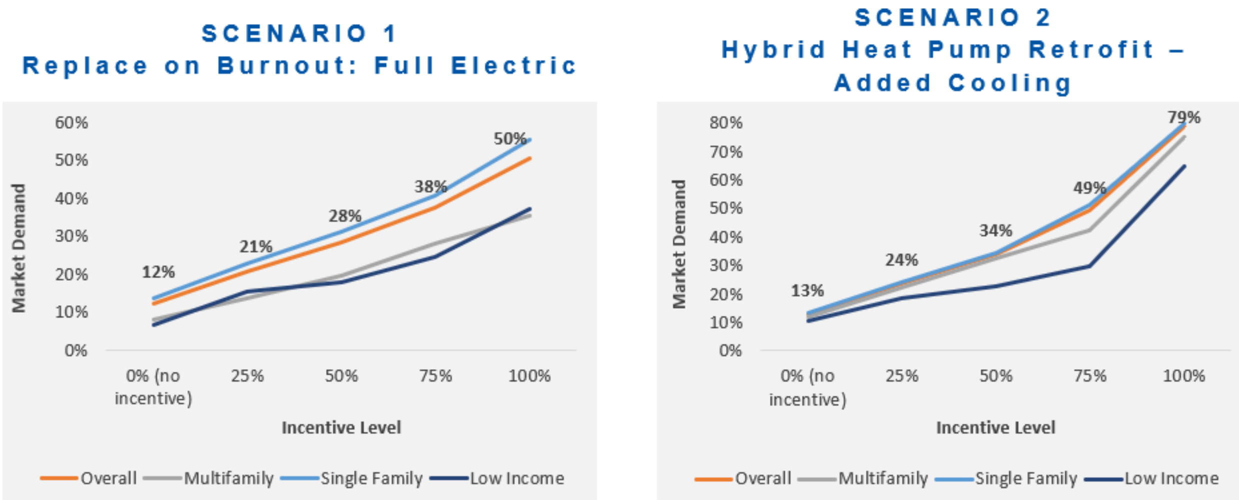
[17] McKinsey & Company. May 28, 2020. "Plugging In: What Electrification Can Do for Industry." https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/plugging-in-what-electrification-can-do-for-industry

Figure 23. Customers Willingness to Adopt Electric Equipment by Heat Pump Type and Incentive Level



Contractor and Builder Interviews

Cadmus conducted contractor and builder interviews to determine heat pump (hybrid, ductless, ducted, and cold climate) conversion costs, including any additional costs to convert to electric from non-electric equipment, such as electrical panel or wiring upgrades, duct reconfiguration, and added labor costs. We asked interview questions to find out what heat pump conversion equipment contractors and builders would recommend for specific non-electric heating systems (such as duct systems, boilers, and wall units) and to determine if there were certain barriers to converting to electric heating systems. The results directly informed the electrification costs and modeled equipment types.

Contractors reported that electrical improvements are the greatest challenge when installing heat pumps in previously natural gas–heated homes, with minor improvements needed over 50% of the time (such as wiring and conduit). More significant improvements are needed approximately 10% of the time (such as panel or 200-amp electrical service upgrades).

More details of the customer survey and constructor/builder interviews are available in ***Appendix A. Heat Pump Research Findings***.

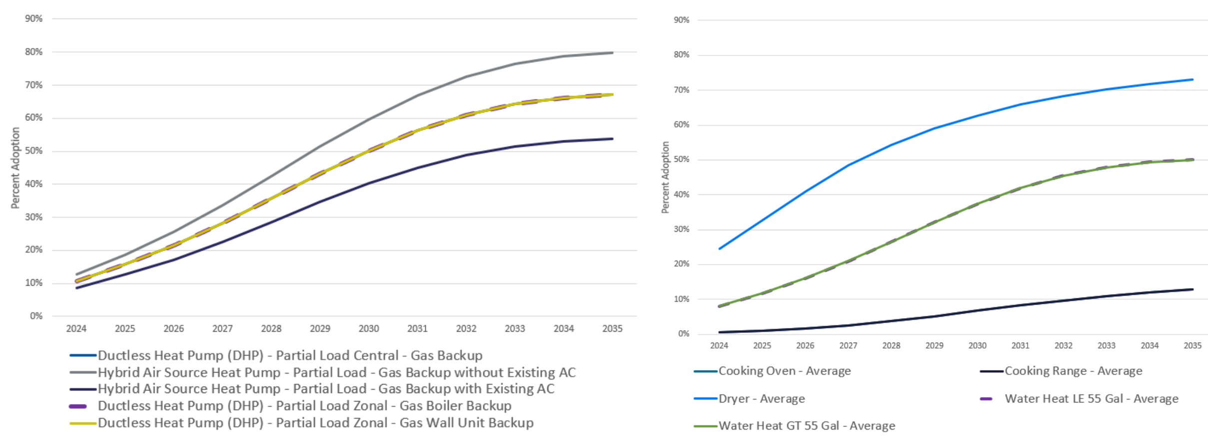
Natural Gas–to-Electric Adoption Rates

Cadmus assessed each supply curve alternative using the product of technical potential (total units available for conversion) and both the maximum achievability factor and the ramp rate percentage. Maximum achievability factors represent the maximum proportion of technical potential that can be acquired over the study horizon. The data from the customer survey informed the hybrid heat pump – market scenario maximum achievability factor and varied for each technology and application (based on incentives representing 100% of the incremental costs). For the policy scenarios, we assumed the maximum achievability factor as 100%.

Ramp rate percentage are annual percentage values representing the proportion of technical annual potential that can be acquired in a given year (equipment/lost opportunity measures). For each supply curve alternative, equipment ramp rates are applied to the proportion of technical annual potential that can be acquired in a given year. Ramp rates are measure-specific and we based these on the ramp rates developed for the Council's draft *2021 Power Plan* supply curves, adjusted to account for the 2024 to 2050 study horizon. We assumed that, under the policy scenarios, there will be phase-in policies over time and customers will ramp-up to 100% adoption over the study horizon.

Figure 24 shows the residential hybrid heat pump – market scenario of annual ramp rate and maximum achievability factor for this technology. The heat pump ramp rate is based on the Council's heat pump adoption (Lost Opportunity 5 Medium). Cadmus estimated the maximum adoption of 75% for clothes dryers and assumed limited market barriers. For this scenario, we assumed water heat to have 50% maximum adoption, similar to ASHPs. We assumed cooking equipment to have 14% maximum adoption based on the customer survey (without incentives).

Figure 24. Residential Adoption Curve Hybrid Heat Pump – Market Scenario (Single Family Example)



In Figure 25 the residential policy scenarios (hybrid heat pump – policy and full electrification – policy) shows the maximum adoption reaching 100% in the latter half of the study horizon. For the commercial sector, the space heat and water heat maximum adoption was estimated to be 70% based on an ACEEE study.[18] We assumed cooking equipment to have 50% maximum adoption to account for market barriers in converting some natural gas cooking equipment.

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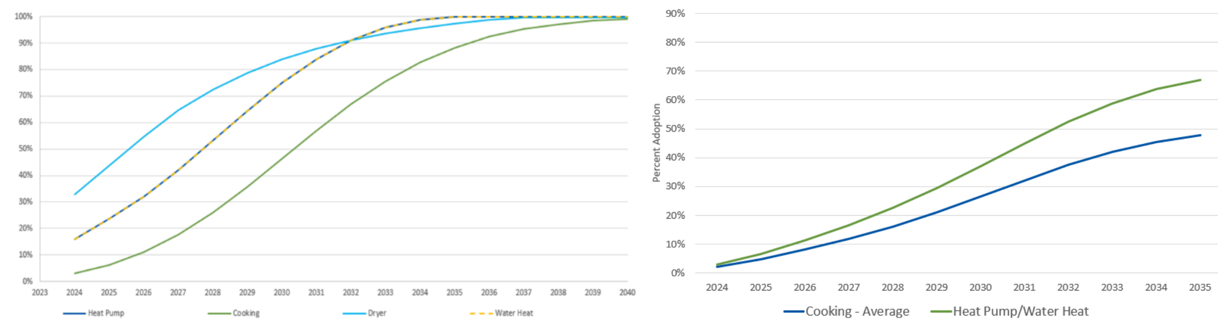
18 American Council for an Energy-Efficient Economy (Nadel, Steven, and C. Perry). October 28, 2020. "Electrifying Space Heating in Existing Commercial Buildings: Opportunities and Challenges." https://www.aceee.org/research-report/b2004

Figure 25. Residential Policy Scenarios (Left) and Commercial Adoption Curves (Right)



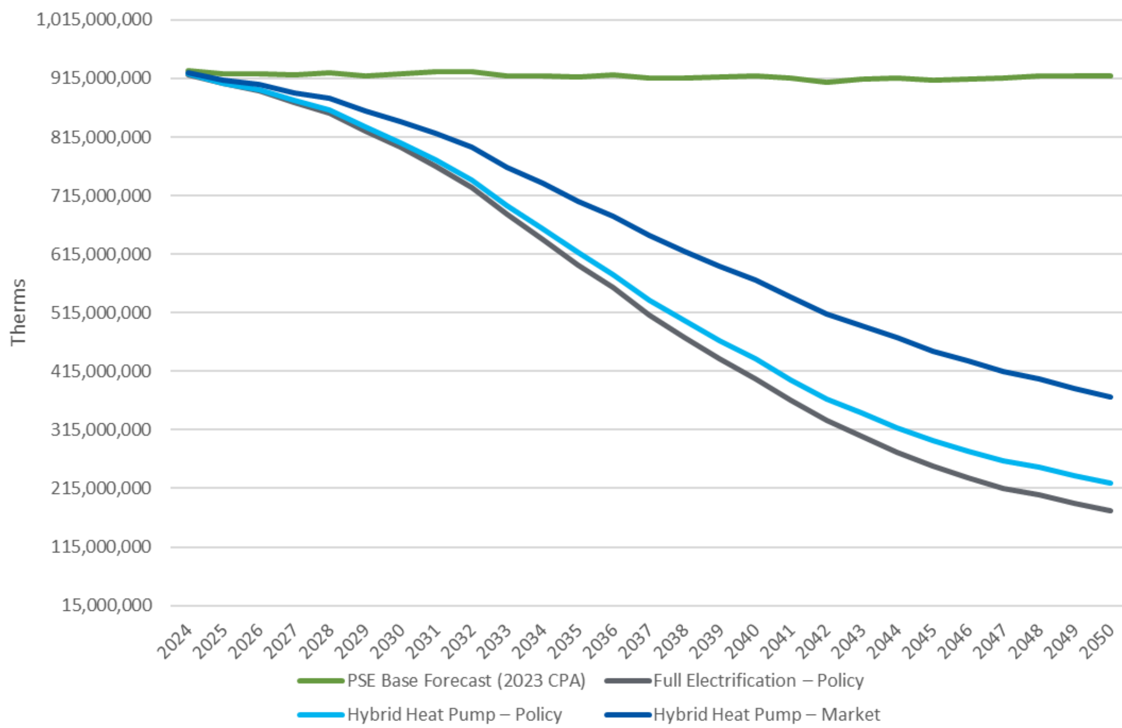
Load Impacts

Cadmus used the natural gas-to-electric change in equipment saturation with the applied adoption rates to assess the natural gas and electric system load impacts within PSE's service territory from 2024 through 2050. We calculated hourly (electric) and monthly (natural gas) system energy load impacts associated with natural gas–to-electric supply curve alternatives. We used hourly end-use profiles from the draft *2021 Power Plan* and we estimated hourly profiles for hybrid and natural gas backup based on building simulations.

Natural Gas Reduction Impacts

Cadmus calculated the associated natural gas reductions at the system level for each of the supply curve alternatives. The hybrid heat pump – market scenario is presented in figures below and represents the maximum impact if PSE's IRP portfolio model selects all measures (regardless of cost). We know that not all technologies will ultimately be selected within the IRP but this maximum market scenario provides additional context and comparison for the other scenarios. Figure 26 shows that the full electrification policy decreases the natural gas base sales forecast by 81% in 2050 from the PSE base forecast (2023 CPA), whereas the hybrid heat pump – policy scenario decreases the sales forecast by 76% and the hybrid heat pump – market scenario decreases the sales forecast by 60% (assuming all measures are found to be cost effective and selected in the IRP portfolio model). The C&I natural gas–to-electric supply curves do not change between each scenario. As a result, the change in natural gas reductions shown in Figure 26 comes from differences in the residential equipment (heat pump versus hybrid/backup).

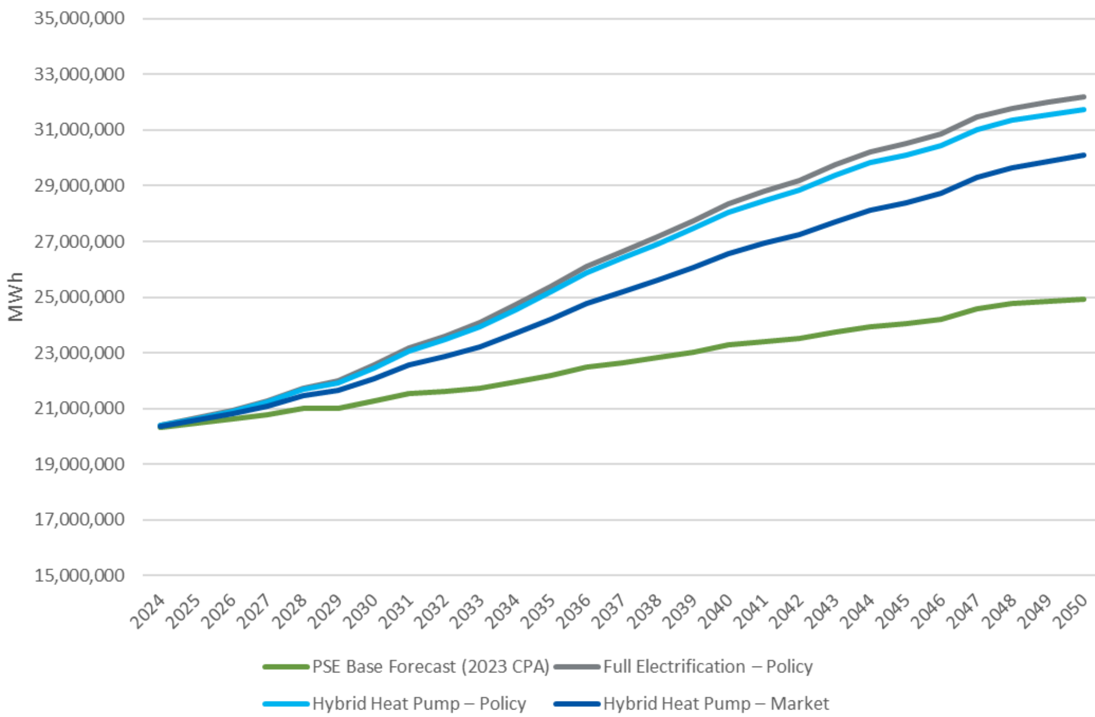
Figure 26. Natural Gas Load Impact by Scenario 2024–2050 (Therms)



Electric Energy Impacts

Figure 27 shows the electric energy impacts by scenario of converting natural gas–to-electric equipment from 2024 to 2050. The full electrification policy increases the electric base sales forecast by 29% in 2050 from the PSE base forecast (2023 CPA), whereas the hybrid heat pump – policy scenario increases the sales forecast by 27% and the hybrid heat pump – market scenario increases the sales forecast by 21% (assuming all measures are found to be cost effective and selected in the IRP portfolio model).

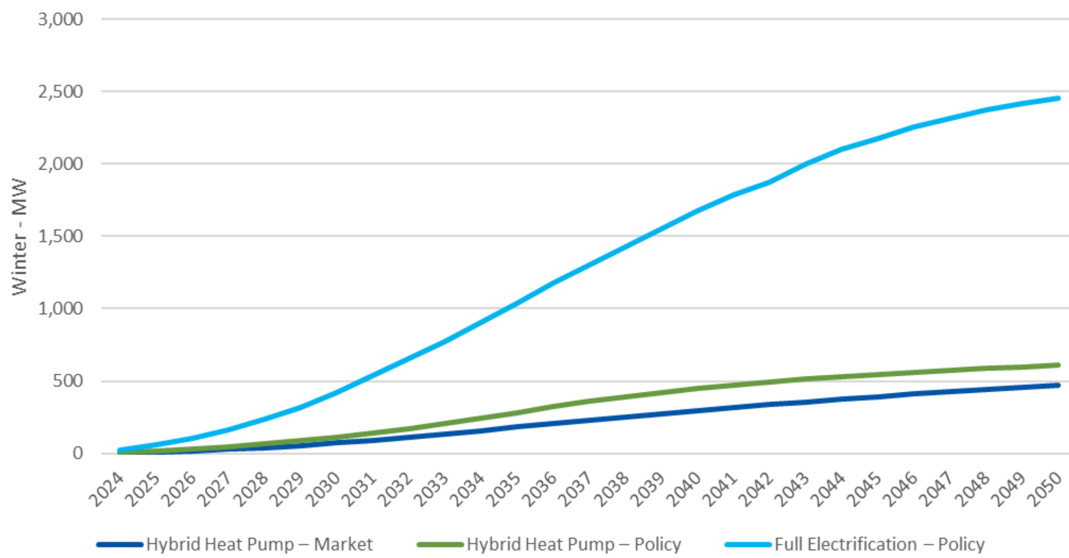
Figure 27. Electric Load Impact by Scenario 2024–2050 (MWh)



Peak Demand Impacts

Cadmus calculated the cumulative peak winter demand impacts in PSE's electric service area as shown in Figure 28 by supply curve alternative from 2024 to 2050. The predominate increase in electric peak winter demand comes from the full electrification policy supply curve. This is due to heat pumps without natural gas backup operating during peak, whereas in the hybrid scenarios the natural gas heating equipment operates during peak and results in zero peak demand increases. The end uses represented in the hybrid scenarios peak demand are from water heaters, dryers, cooking, and commercial and industrial equipment. These end-uses are less coincident to PSE's winter peak (under extreme weather conditions).

Figure 28. Cumulative Electric Winter Demand Impacts by Scenario (MW)



Energy Efficiency Impacts

Cadmus took the interaction with energy efficiency savings into account and assessed both electric and natural gas energy efficiency potential for both policy scenarios, as shown in Table 14. The market scenario was not evaluated for the energy efficiency impacts, since the cost effective amount of HHP will only be known after the gas portfolio analysis is complete.

Table 14. Full Electrification and Hybrid Heat Pump Policy Scenario Impacts on Electric and Natural Gas Energy Efficiency Potential

Sector	Achievable Technical Potential, Cumulative 2050		
	27-Year Base Energy Efficiency Potential	Full Electrification – Policy Scenario 27-Year Energy Efficiency Potential	Hybrid Heat Pump – Policy Scenario 27-Year Energy Efficiency Potential
Electric (MWh)			
Residential	2,614,783	4,049,002	3,602,076
Commercial	2,020,415	2,303,609	2,303,609
Industrial	162,004	163,938	163,938
Total	**4,797,202**	**6,516,549**	**6,069,624**
Natural Gas (MMTherms)			
Residential	111	26	31
Commercial	51	19	19
Industrial	3	3	3
Total	**165**	**48**	**53**

The Full Electrification – Policy scenario has a 36% higher electric energy efficiency potential and 71% lower natural gas energy efficiency potential from equipment and retrofit measures compared to Hybrid Heat Pump – Policy scenario. The Hybrid Heat Pump – Policy scenario has a 27% higher electric energy efficiency potential and 68% lower natural gas energy efficiency potential than the base potential scenario.

Levelized Costs Calculations

To incorporate the natural gas–to-electric scenario results in PSE's IRP scenario, Cadmus developed levelized cost estimates for the natural gas reductions, which PSE modeled comparably to energy efficiency. The potential is grouped by levelized cost over 27-year period for the natural gas reductions. The 27-year natural gas levelized-cost calculations incorporate numerous factors, shown in Table 15.

Table 15. Levelized Cost Components

Type	Component
Costs Included[1]	Present Value Capital Cost of Equipment Conversion
	Program Cost (HVAC equipment program admin adder based on energy efficiency potential estimates, all other end-uses based on 21% of equipment conversion cost)
	Added Electric Transmission and Distribution Costs (for non-hybrid systems)
	Panel Upgrade Cost
Benefits Netted Out	Present Value of Natural Gas Avoided
	Present Value of Conservation Credit (10% of conserved natural gas energy)
	Present Value of Non-Energy Impacts

[1]Costs for the electric energy generation and capacity are an output of PSE's electric portfolio analysis.

Cadmus incorporated the costs associated with expanding the existing transmission and distribution to meet the new electric peak demands (as PSE's IRP model accounts for these variables). PSE's generation capacity and transmission and distribution system would require increased investments to handle the increased load due to electrification. Cadmus accounted for the T&D costs for all non-hybrid heat pump systems (we modeled hybrid systems to have zero impact during winter peak).

In addition to the annual natural gas energy savings from converted away from natural gas, the total resource cost levelized-cost calculation incorporates several other factors:

- ***Capital cost of equipment conversion.*** Cadmus considered the costs required to sustain savings over a 27-year horizon, including reinstallation costs for measures with an effective useful life (EUL) of less than 27 years. If a measure's EUL extends beyond the end of the 27-year study, Cadmus incorporated an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 27-year period.[19] Additional costs, besides equipment, included wiring and panel upgrades for a portion of PSE's population.
- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 21% of incremental measure costs for non-HVAC measures. For HVAC equipment, Cadmus used nominal values (rather than a percent of incremental cost) from the energy efficiency potential

[19] In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%). Cadmus applied this method both to measures with an EUL of greater than 27 years and to measures with an EUL that extends beyond the study horizon at the time of reinstallation.

estimates for the program administrative adders since natural gas-to-electric incremental costs tend to be larger than costs for traditional energy efficiency upgrades.

- ***Non-energy impacts.*** This study incorporated NEIs for residential customers who did not have existing cooling but received cooling comfort through the installation of the heat pump.
- ***The regional 10% conservation credit.*** The addition of this credit per the Northwest Power Act[20] is consistent with the Council's methodology and is effectively an adder to account for the unquantified external benefits of conservation when compared to other resources. This credit is only applied to the natural gas savings.

For more information on levelized costs calculations, see the *Integrated Resource Plan Input Development* section with details of the energy efficiency methodology.

Effect of Natural Gas-to-Electric Conversion on Demand Response Potential

Demand response programmatic options help reduce peak demand during system emergencies or periods of extreme market prices and promote improved system reliability. Demand response programs provide incentives for customers to curtail loads during utility-specified events (such as direct load control [DLC] programs) or offer pricing structures to induce participants to shift load away from peak periods (such as critical peak pricing [CPP] programs).

As the last step, Cadmus analyzed the magnitude of impacts of the natural gas–to-electric conversion on demand response potential. For this purpose, Cadmus focused on the same programs that were analyzed in "Demand-Side Electric Resource Potential Assessment"[21] and aimed at reducing PSE's winter and summer peak demand. These programs include residential and commercial DLC HVAC, residential DLC water heat, residential electric vehicle supply equipment (EVSE), residential and C&I CPP, and C&I load curtailment and provide options for all major customer segments and end uses in PSE's service territory. Each of these programs may have more than one product option. For example, the residential DLC water heat program is available for customers with either a HPWH or electric resistance water heater (ERWH). A water heater can also be grid-enabled or controlled by a switch.

Cadmus mainly based the program assumptions on the inputs used in the draft *2021 Power Plan*, with a few modifications to account for additional benchmarking. Details of these inputs can be found in a separate companion report titled *Comprehensive Assessment of Demand-Side Electric Resource Potential (2024–2050)*. To determine the impact of natural gas–to-electric conversion on demand response potential, Cadmus made some adjustments to the inputs. For the residential sector, we increased the number of ASHPs, DHPs, electric water heaters, dryers, and cooking equipment for each of three scenarios. Similarly, for commercial sector, we increased the number of ASHPs, water heaters, and

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[20] Northwest Power and Conservation Council. January 1, 2010. "Northwest Power Act." http://www.nwcouncil.org/library/poweract/default.htm

[21] The PSE CPA results for electric demand-side resource potential in terms of demand response can be found in a separate companion report titled *Comprehensive Assessment of Demand-Side Electric Resource Potential (2024–2050)*.

cooking equipment. In addition, we increased the total electric load (MWh) for each sector due to the additional load from natural gas–to-electric conversion.

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
• More increase in electric load in Full Electrification – Policy scenario than in Hybrid Heat Pump – Policy scenario • Increase in equipment counts: **Hybrid Heat Pump – Policy scenario** Hybrid ASHPs, DHPs-partial load, DHPs-new construction full replacement, water heaters, dryers, stoves/cooktops **Full Electrification – Policy scenario** ASHPs, DHPs-full replacement, water heaters, dryesr, stoves/cooktops	• Increase in electric load at the same level for all scenarios • Increase in equipment counts for ASHPs, water heaters, and cooking equipment	Increase in electric load at the same level for all scenarios

After making these adjustments, we estimated the potential for two different natural gas–to-electric conversion scenarios, shown in Table 16. Although PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the demand response potential for the summer season, shown in Table 17.

Table 16. Comparison of Achievable Potential: Base Case and Policy Scenarios, Winter 2050

Program	Product Option	Base Case (MW)	Hybrid Heat Pump – Policy (MW)	Full Electrification – Policy (MW)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0	0
	Residential ERWH DLC Grid-Enabled	32	63	63
	Residential HPWH DLC Switch	0	0	0
	Residential HPWH DLC Grid-Enabled	58	114	114
Residential DLC HVAC	Residential HVAC DLC Switch	97	102	173
	Residential Bring-Your-Own Thermostat (BYOT) DLC	108	122	356
Residential DLC EVSE	Residential EVSE DLC Switch	42	42	42
Residential CPP	Residential CPP	33	46	47
	Residential Sector Total	**371**	**488**	**794**
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	18	45	45
	Small Commercial HVAC DLC Switch	3	7	7
	Small Commercial BYOT DLC	3	18	18
C&I Curtailment	Commercial Curtailment	16	18	18
Commercial CPP	Commercial CPP	21	24	24
	Commercial Sector Total	**61**	**112**	**112**
C&I Curtailment	Industrial Curtailment	5	6	6
Industrial CPP	Industrial CPP	2	2	2
	Industrial Sector Total	**7**	**8**	**8**
	Total	**439**	**607**	**913**

Table 17. Comparison of Achievable Potential: Base Case and Policy Scenarios, Summer 2050

Program	Product Option	Base Case (MW)	Hybrid Heat Pump – Policy (MW)	Full Electrification – Policy (MW)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0	0
	Residential ERWH DLC Grid-Enabled	22	42	42
	Residential HPWH DLC Switch	0	0	0
	Residential HPWH DLC Grid-Enabled	29	57	57
Residential DLC HVAC	Residential HVAC DLC Switch	50	68	68
	Residential BYOT DLC	100	184	184
Residential DLC EVSE	Residential EVSE DLC Switch	42	42	42
Residential CPP	Residential CPP	74	101	101
	Residential Sector Total	**316**	**493**	**493**
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	77	116	116
	Small Commercial HVAC DLC Switch	5	8	8
	Small Commercial BYOT DLC	4	9	9
C&I Curtailment	Commercial Curtailment	20	23	23
Commercial CPP	Commercial CPP	26	30	30
	Commercial Sector Total	**133**	**185**	**185**
C&I Curtailment	Industrial Curtailment	5	6	6
Industrial CPP	Industrial CPP	2	2	2
	Industrial Sector Total	**7**	**8**	**8**
	Total	**455**	**686**	**686**

Hybrid Heat Pump – Policy

Figure 29 shows the acquisition schedule for demand response achievable technical potential by product for winter. Product potential ramps up fast in the early years of the study and slows down once the market has become close to maturity. Residential HVAC makes up most of the available winter demand response potential due to the increased number of heat pumps. It should be noted that the demand response potential shown represents the achievable technical potential and includes both cost-effective and non-cost-effective demand response products.

Figure 29. Demand Response Achievable Technical Potential Forecast by Program for Hybrid Heat Pump – Policy Scenario, Winter

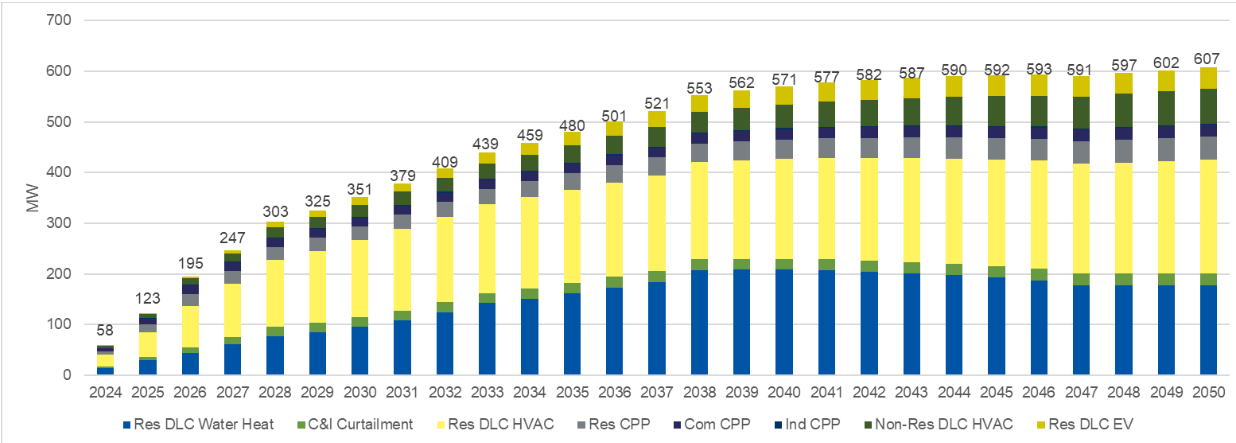
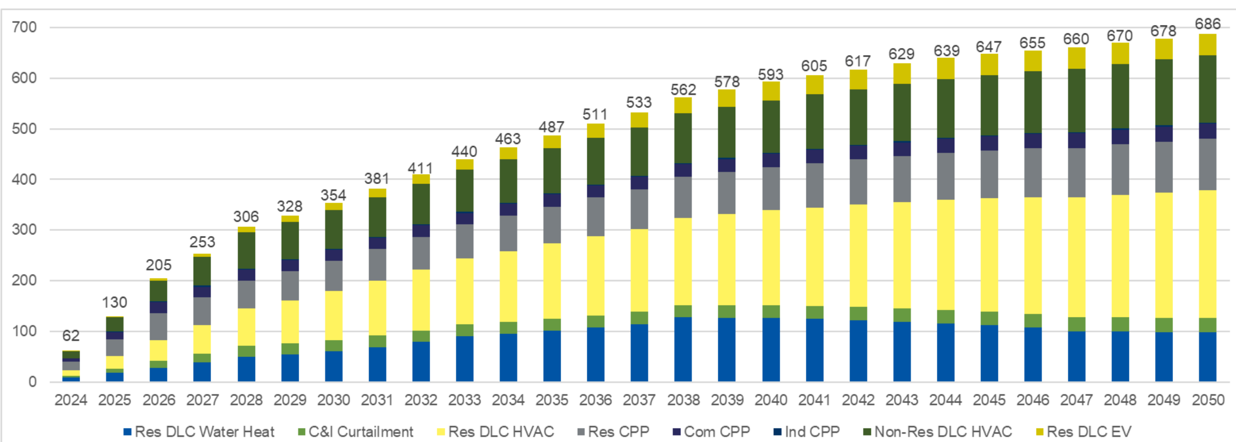


Figure 30 shows the acquisition schedule for demand response achievable technical potential by program for summer. The dynamics in the summer are similar to those seen in the winter, though the overall potential is higher.

Figure 30. Demand Response Achievable Technical Potential Forecast by Program for Hybrid Heat Pump – Policy Scenario, Summer



Full Electrification – Policy

Figure 31 shows the acquisition schedule for demand response achievable technical potential by product for winter. Product potential ramps up fast in the early years of the study and slows down once the market has become close to maturity. Similar to the Hybrid Heat Pump – Policy scenario, residential HVAC makes up most of the available winter demand response potential due to the increased number of heat pumps. However, when compared to Hybrid Heat Pump – Policy scenario results (Figure 29), the Full Electrification – Policy scenario created more potential through Residential BYOT, Residential HVAC DLC Switch, and Residential CPP products due to not having backup natural gas heating.

Figure 31. Demand Response Achievable Technical Potential Forecast by Program for Full Electrification – Policy Scenario, Winter

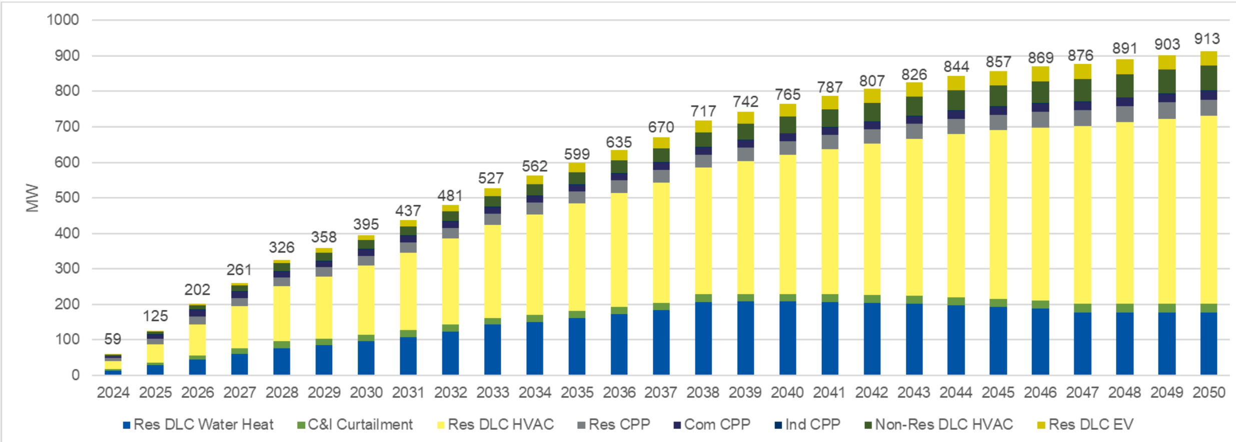
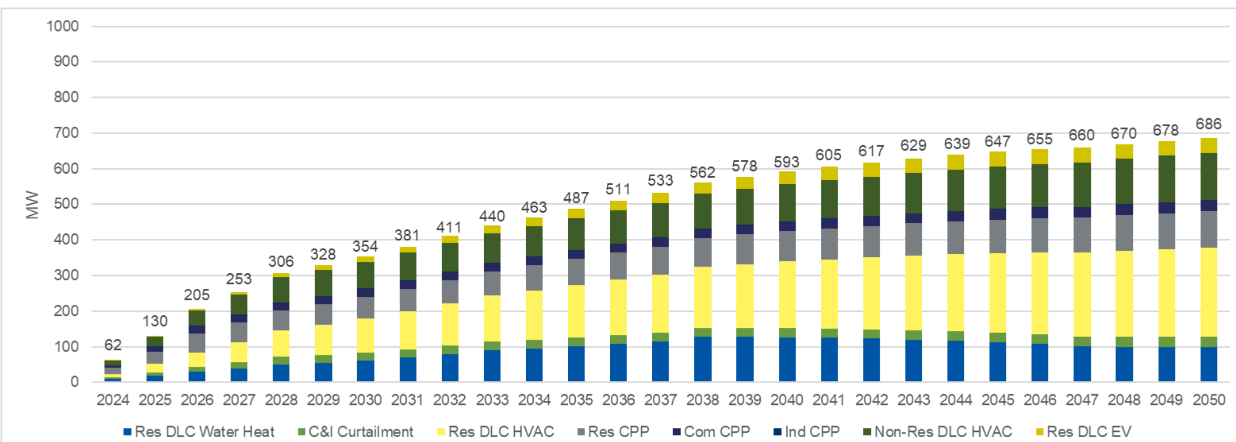


Figure 32 shows the acquisition schedule for demand response achievable technical potential by program for summer. For the Full Electrification – Policy scenario, demand response potential is the same as that for the Hybrid Heat Pump – Policy scenario because of having no difference in the number of equipment as well as no difference in per-unit impacts between these two scenarios.

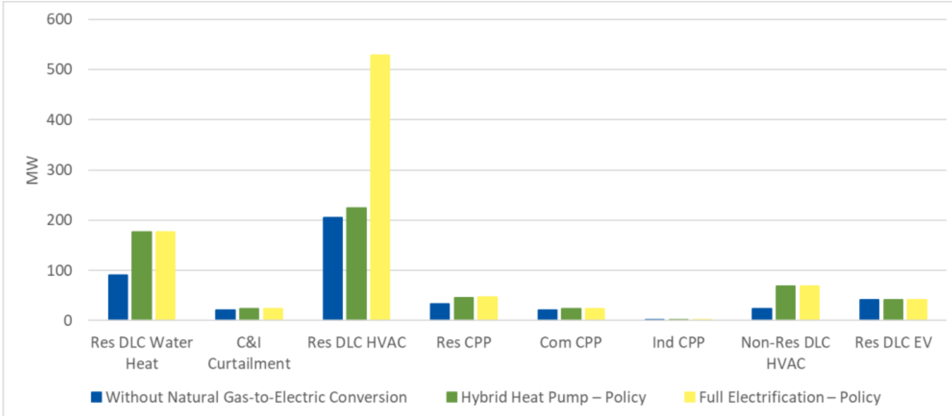
Figure 32. Demand Response Achievable Technical Potential Forecast by Program for Full Electrification – Policy Scenario, Summer



Comparison of Natural Gas-to-Electric Conversion Scenarios with Base Case

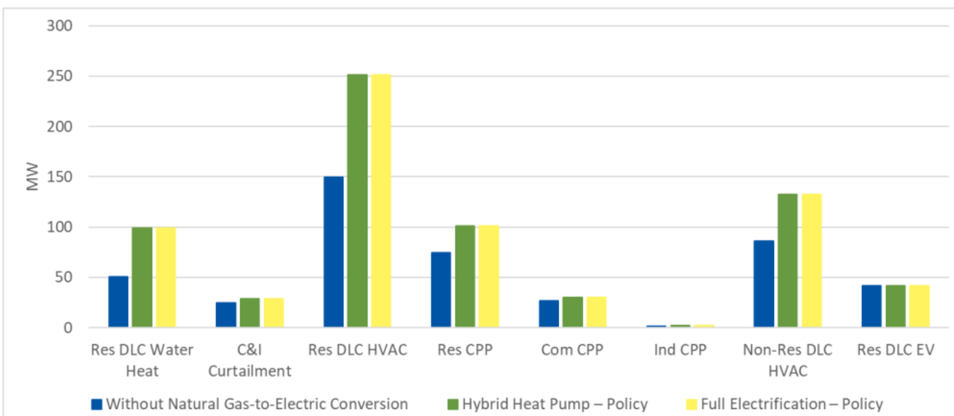
Figure 33 presents the impact of natural gas–to-electric conversion on winter demand response potential by comparing the base case (where there is no natural gas–to-electric conversion) with both scenarios.

Figure 33. Comparison of Natural Gas-to-Electric Conversion Scenarios with the Base Case, Winter 2050



As mentioned before, even though PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the impact of natural gas–to-electric conversion on summer demand response potential demand, shown in Figure 34.

Figure 34. Comparison of Natural Gas-to-Electric Conversion Scenarios with the Base Case, Summer 2050



Except Residential DLC EV, all the products show the impact of natural gas–to-electric conversion on the base case to different extents. The most notable impact is between the base case and Full Electrification – Policy scenario in the Residential DLC HVAC program for winter due to the increasing electric heating load.

Chapter 4. Energy Efficiency Methodology Details

This chapter describes Cadmus' methodology for estimating the potential of demand-side resources in PSE's service territory between 2024 and 2050 and for developing supply curves for modeling demand-side resources in PSE's IRP. We describe the calculations for technical and achievable technical potential, identify the data sources for components of these calculations, and discuss key global assumptions. To estimate the demand-side resource potential, Cadmus analyzed many conservation measures across many sectors, with each measure requiring nuanced analysis. This chapter does not describe the detailed approach for estimating a specific measure's UES or cost, but it does show the general calculations we used for nearly all measures.

Cadmus' methodology for calculating energy efficiency potential can be best described as a combined top-down, bottom-up approach. We began the top-down component with the most current load forecast, adjusting for building codes, equipment efficiency standards, and market trends that are not accounted for through the forecast. Cadmus then disaggregated this load forecast into its constituent customer sectors, customer segments, and end-use components and projected the results out 27 years. We calibrated the base year (2023) to PSE's sector-load forecasts produced in 2022.

For the bottom-up component, we considered potential technical impacts of various ECMs and practices on each end use. We then estimated impacts based on engineering calculations, accounting for fuel shares (the proportion of units using electricity versus natural gas), current market saturations, technical feasibility, and costs. The technical potential presents an alternative forecast that reflects the technical impacts of specific energy efficiency measures. Cadmus then determined the achievable technical potential by applying ramp rates and achievability percentages to technical potential. The CPA methodology is described in detail in the following sections.

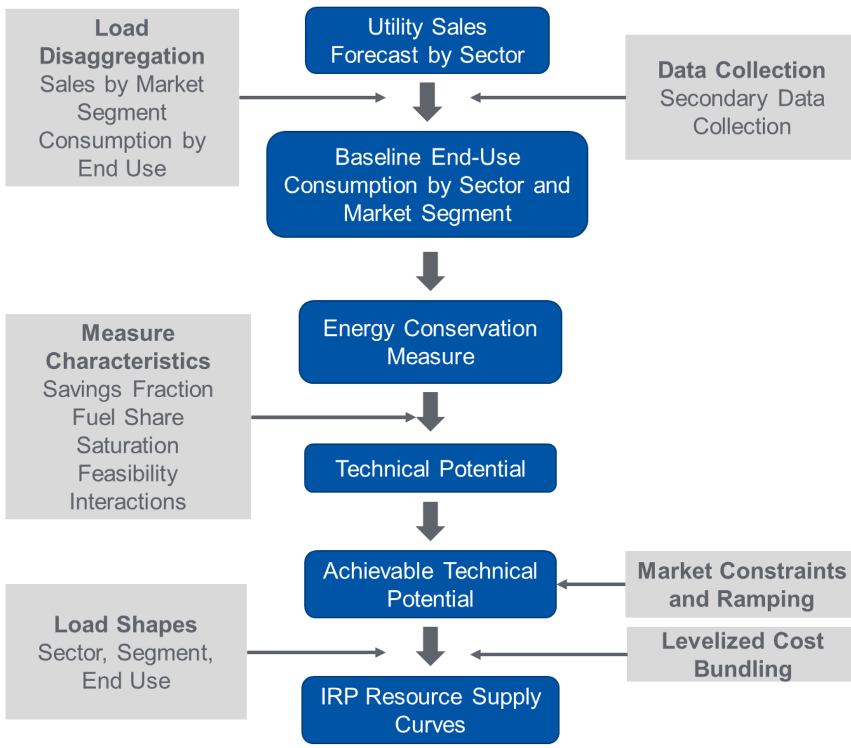
Cadmus followed a series of steps to estimate energy efficiency potential, described in detail in the subsections below:

- ***Market segmentation.*** Cadmus identified the sectors and segments for estimating energy efficiency potential. Segmentation accounts for variation across different parts of PSE's service territory and across different applications of energy efficiency measures.
- ***ECM characterization.*** Cadmus researched viable ECMs that can be installed in each segment. The description for this step below includes the components and data sources for estimating measure savings, costs, applicability factors, lifetimes, baseline assumptions, and the treatment of federal standards.
- ***Baseline end-use load forecast development.*** Cadmus developed baseline end-use load forecasts over the planning horizon and calibrated the results to the PSE's corporate forecast in the base year (2023).

- ***Conservation potential estimation.*** Cadmus forecasted technical potential, relying on the measure data compiled from prior steps and the achievable technical potential, which we based on technical potential and additional terms to account for market barriers and ramping.
- ***IRP input development.*** Cadmus bundled forecasts of achievable technical potential by levelized costs, so PSE's IRP modelers can consider energy efficiency as a resource within the IRP.

Figure 35 provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

Figure 35. Overview of Energy Efficiency Methodology



Market Segmentation

Market segmentation involved first dividing PSE's natural gas service territories into sectors and market segments. Careful segmentation accounts for variation in building characteristics and savings across the service territory. To the extent possible, energy efficiency measure inputs reflect primary data, such as the NEEA 2019 CBSA, the NEEA 2017 RBSA, and the PSE's RCS.

Considering the benefits and drawbacks of different segmentation approaches, Cadmus identified three parameters that produce meaningful and robust estimates:

- ***Service territories and fuel.*** PSE's natural gas service territory
- ***Sector.*** Residential, commercial, industrial, and small transport
- ***Industries and building types.*** Three residential segments (with the corresponding vulnerable population segments), 18 commercial segments, 18 industrial segments, and 29 small transport segments

Table 18 lists the sectors and associated segments modeled in this study.

Table 18. Sectors and Segments Modeled

Residential	Commercial	Industrial	Small Transport	
			Commercial	**Industrial**
• Manufactured • Manufactured - Vulnerable Population • Multifamily • Multifamily - Vulnerable Population • Single Family • Single Family - Vulnerable Population	• Assembly • Extra Large Retail • Hospital • Large Office • Large Retail • Lodging • Medium Office • Medium Retail • Mini-Mart • Residential Care • Restaurant • School K–12 • Small Office • Small Retail • Supermarket • University • Warehouse • Other	• Cement • Chemical • Cold Storage • Food - Frozen • Food - Other • Foundries • Fruit Storage • Hi Tech - Chip Fabrication • Hi Tech - Silicon • Mechanical Pulp • Metal Fabrication • Miscellaneous Manufacturing • Paper • Refinery • Transportation Equipment • Wood - Lumber • Wood - Other • Wood - Panel	• Assembly • Extra Large Retail • Hospital • Large Office • Lodging • Residential Care • Restaurant • School K–12 • Supermarket • Warehouse • Other	• Cement • Chemical • Cold Storage • Food – Frozen • Food – Other • Foundries • Fruit Storage • Hi Tech – Chip Fabrication • Hi Tech – Silicon • Mechanical Pulp • Metal Fabrication • Miscellaneous Manufacturing • Paper • Refinery • Transportation Equipment • Wood – Lumber • Wood – Other • Wood – Panel

Energy Efficiency Measure Characterization

Technical potential draws upon an alternative forecast and should reflect installations of all technically feasible measures. To accomplish this, Cadmus chose the most robust set of appropriate ECMs by developing a comprehensive database of technical and market data that applied to all end uses in various market segments. Throughout this process, we calculated ECM savings as UES or measure percentage savings to estimate the end-use percentage savings. These measures' end-use percentage savings, when applied to the baseline end-use forecasts, produce estimates of energy efficiency potential.

The database included several measures:

- All measures in the PSE business case workbooks
- Active UES measures in the RTF
- Some dual fuel measures in the Council's draft *2021 Power Plan* conservation supply curve workbooks
- Industrial measures derived from the "Industrial Assessment Center Database (2000–2021)"
- Other Cadmus derived measures

Cadmus classified the natural gas energy efficiency measures applicable to PSE's service territories into two categories:

LOST OPPORTUNITY	DISCRETIONARY
High-efficiency equipment measures directly affecting end-use equipment (such as high-efficiency boilers), which follow normal replacement patterns based on expected lifetimes	**Non-equipment (retrofit)** measures affecting end-use consumption without replacing end-use equipment (such as insulation). Such measures do not include timing constraints from equipment turnover—except for new construction—and should be considered discretionary, given that savings can be acquired at any point over the planning horizon.

Cadmus assumed that all high-efficiency equipment measures would be installed at the end of the existing equipment's remaining useful life; therefore, we did not assess energy efficiency potential for early replacement.

Each measure type has several relevant inputs:

Equipment and non-equipment measures:

- Energy savings: Average annual savings attributable to installing the measure, in absolute (therm per unit) and/or percentage terms.
- Equipment cost: Full or incremental, depending on the nature of the measure and the application.
- Labor cost: The expense of installing the measure, accounting for differences in labor rates by region and other variables.
- Technical feasibility: The percentage of buildings where customers can install this measure, accounting for physical constraints.
- Measure life: The expected life of the measure equipment.
- Non-energy impacts: The annual dollar savings per year associated with quantifiable non-energy benefits.
- Savings shape. We assigned an hourly savings shape to each measure, which we then used to disaggregate annual forecasts of potential into monthly estimates.

Non-equipment measures only:

- Percentage incomplete: The percentage of buildings where customers have not installed the measure, but where its installation is technically feasible. This equals 1.0 minus the measure's current saturation.
- Measure competition: For mutually exclusive measures, accounting for the percentage of each measure likely installed to avoid double-counting savings.
- Measure interaction: Accounting for end-use interactions (for example, installing a high efficiency clothes washer serviced by a gas water heater reduces the remaining moisture content in clothing which in turn lowers the required natural gas dryer load required to dry the clothes).

Cadmus derived these inputs from various sources, though primarily through four main sources:

- NEEA CBSA IV, including PSE's oversample, where applicable
- NEEA RBSA II with PSE's oversample
- The RTF UES measure workbooks
- The Council's draft *2021 Power Plan* conservation supply curve workbooks

For many equipment and non-equipment inputs, Cadmus reviewed a variety of sources. To determine which source to use for this study, Cadmus developed a hierarchy for costs and savings:

1. PSE business cases
2. RTF UES measure workbooks
3. The Council's draft *2021 Power Plan* conservation supply curve workbooks (for some dual fuel measures)
4. Secondary sources, such as Simple Energy and Enthalpy Model building simulations, U.S. Department of Energy's "Industrial Assessment Center Database (2000–2021)," or various technical reference manuals

Cadmus also developed a hierarchy to determine the source for various applicability factors, such as the technical feasibility and the percentage incomplete. This hierarchy differed slightly for residential and commercial measure lists.

Non-Energy Impacts

In this CPA, Cadmus included a wider range of NEIs (such as health and safety, comfort, and productivity) compared to the 2021 CPA, which resulted in additional NEIs for more measures. In 2021, PSE conducted an NEI evaluation study[22] to expand the NEIs; the full list is shown in Table 19.

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[22] DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report*.

Table 19. List of Non-Energy Impacts

NEI Name	NEI Type	Definition
Residential		
Avoided Illness from Air Pollution	Societal	Modeled value of avoided particulate matter 2.5 microns or less (PM2.5) associated with electricity generation at power plant. Does not include carbon dioxide.
Bad Debt Write Offs	Utility	Reduction in cases of bad debt write offs.
Calls to Utility	Utility	Reduction in number of calls to utility from customers.
Carrying Cost on Arrearages	Utility	Reduced carrying cost on arrearages.
Ease of Selling or Leasing	Participant	Participant-reported improved ability to sell or lease property due to increased performance and desirability.
Fires/Insurance Damage	Participant	Avoided cost of fires based on insurance estimates.
Health and Safety	Participant	Participant-reported costs from time off and lost pay due to fewer missed days of work/school, less heat/cold stress, and similar, resulting from measures installed in the home.
Lighting Quality and Lifetime	Participant	Participant-reported value of improved lighting lumen levels, color, and steadiness.
Noise	Participant	Participant-reported value associated with reduced amount of outside noise that can be heard inside the home.
O&M	Participant	Modeled avoided time and costs associated with reduced maintenance, parts/repairs, service visits, and system monitoring
Other Impacts	Participant	Includes participant impacts not covered in the other categories such as reduced tenant turnover.
	Utility	Includes rate discounts and price hedging.
		Includes low-income subsidies avoided.
Productivity	Participant	Participant-reported value resulting from improved rest, sleep, and living conditions associated with energy efficiency improvements.
Thermal Comfort	Participant	Increased comfort due to fewer drafts and more even temperatures throughout the building.
Commercial and Industrial		
Administrative Costs	Participant	Participant-reported avoided overhead costs associated with invoice processing, parts/supplies procurement, contractor coordination, and customer complaints.
Avoided Illness from Air Pollution	Societal	Modeled value of avoided particulate matter 2.5 microns or less (PM2.5) from electric power generation associated with electricity generation at power plant. Does not include carbon dioxide.
Ease of Selling or Leasing	Participant	Participant-reported improved ability to sell or lease property due to increased performance and desirability.
Fires/Insurance Damage	Participant	Avoided cost of fires based on insurance estimates.
Lighting Quality and Lifetime	Participant	Participant-reported value of improved lighting lumen levels, color, and steadiness.
O&M	Participant	Avoided time and costs associated with reduced maintenance, parts/repairs, service visits, and system monitoring.
Other Impacts	Participant	Includes rent revenues, employee satisfaction, and other labor costs (defined as other labor at the company not covered in O&M, administrative costs, supplies, and materials).
		Included modeled value of decreased usage of fuel, propane, and other sources.

NEI Name	NEI Type	Definition
Product Spoilage/Defects	Participant	Participant-reported value of avoided product losses (such as reduced food spoilage in grocery stores).
Productivity	Participant	Participant-reported value of improved workplace productivity resulting from improved rest and sleep related to improved living conditions.
Sales Revenue	Participant	Participant-reported increased sales resulting from improved product.
Supplies and materials	Participant	Includes changes in the type, amount, or costs of materials and supplies needed.
Thermal Comfort	Participant	Increased comfort due to fewer drafts and more even temperatures throughout the building.
Waste Disposal	Participant	Participant-reported costs to remove solid waste and pay landfill fees (such as fees to dispose of CFLs).
Water/ Wastewater	Participant	Reduced water usage due to efficient equipment.

PSE has been incorporating these NEIs into some business cases; however, at the time of this study being conducted there were still some business cases without this new NEI evaluation embedded. In addition, as mentioned above, Cadmus used the RTF UES and draft *2021 Power Plan* workbooks when a business case was not available for a measure and some RTF and Council measures already had NEI as a water saving, O&M lifetime replacement. Therefore, Cadmus developed the methodological hierarchy presented in Table 20 to account for all available NEI data for all measures applicable.

Table 20. Methodological Hierarchy for Non-Energy Impact Data Inclusion

Measure Type	CPA Action
PSE business case with existing NEI	Use existing business case NEI
PSE business case without existing NEI	Use NEI evaluation study data, if applicable
RTF/Council with existing NEI	Use RTF/Council data and NEI evaluation study data (excluding water saving, O&M lifetime replacements), if applicable
RTF/Council without existing NEI	Use NEI evaluation study data, if applicable

Measure Data Sources

By data input, Table 21 lists the primary sources referenced in the study.

Table 21. Key Measure Data Sources

Data	Residential Source	Commercial Source	Industrial Source
Energy Savings [a]	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	U.S. Department of Energy's "Industrial Assessment Center Database (2000–2021)"
Equipment and Labor Costs	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	U.S. Department of Energy's "Industrial Assessment Center Database (2000–2021)"
Measure Life	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Cadmus research
Technical Feasibility	NEEA RBSA; Cadmus research	NEEA CBSA; Cadmus research	Cadmus research
Percentage Incomplete	NEEA RBSA; PSE program accomplishments; Cadmus research	NEEA CBSA; PSE program accomplishments; Cadmus research	Cadmus research

Data	Residential Source	Commercial Source	Industrial Source
Measure Interaction	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Cadmus research
Non-Energy Impacts	PSE business cases; PSE's NEI evaluation study; [b] draft *2021 Power Plan* supply curve workbooks; RTF	PSE business cases; PSE's NEI evaluation study; [b] draft *2021 Power Plan* supply curve workbooks; RTF	N/A

[a] The draft *2021 Power Plan* does not have natural gas–only measures. Cadmus converted dual fuel measures, such as water heater applications, showerheads, and clothes washer, to represent natural gas impacts. Additionally, we benchmarked space and water heat consumptions for residential applications against both the RTF and draft *2021 Power Plan* consumptions to align electric and natural gas loads for these end uses.

[b] DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report.*

Incorporating Federal Standards and State and Local Codes and Policies

Cadmus' assessment accounted for changes in codes, standards, and policies over the planning horizon. These changes affected customers' energy-consumption patterns and behaviors, and they determined which energy efficiency measures would continue to produce savings over minimum requirements. Cadmus captured current efficiency requirements, including those enacted but not yet in effect.

Cadmus reviewed all local codes, state codes, federal standards, and local and state policy initiatives that could impact this potential study. For the residential and commercial sectors, we considered the local energy code (2018 Seattle Energy Code, 2018 WSEC, and 2018 RCW) as well as current and pending federal standards.

Cadmus reviewed the following codes, standards, and policy initiatives:

- **Federal standards.** All technology standards for heating equipment, water heating, and appliances not covered in or superseded by state and local codes.[23]
- **2018 Seattle Energy Code.** The code prohibits new commercial and multifamily buildings from using electric resistance or fossil fuels for space heating effective June 1, 2021, and electric resistance or fossil fuels for water heating effective January 1, 2022. All other code provisions took effect on March 15, 2021.[24]
- **2018 Washington State Energy Code (WSEC).** The code provides requirements for residential and commercial new construction buildings, except in cases where the 2018 Seattle Energy Code supersedes Washington code. The effective date was February 1, 2021.[25]

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23 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy. Accessed May 2022. "Standards and Test Procedures." https://www.energy.gov/eere/buildings/standards-and-test-procedures

24 City of Seattle, Office of the City Clerk. February 1, 2021. "Council Bill No: CB 119993. An Ordinance Relating to Seattle's Construction Codes." http://seattle.legistar.com/LegislationDetail.aspx?ID=4763161&GUID=A4B94487-56DE-4EBD-9BBA-C332F6E0EE5D

25 Washington State Building Code Council. Accessed May 2022. https://sbcc.wa.gov/

- **2009 Washington State Senate Bill 5854 and Revised Code of Washington (RCW 19.27A.160).** This code requires "… residential and nonresidential construction permitted under the 2031 state energy code achieve a 70% reduction in annual net energy consumption, using the adopted 2006 Washington state energy code as a baseline."
- **2018 Revised Code of Washington (RCW 19.260.040).** These codes set minimum efficiency standards to specific types of products including steam cookers and fryers. The effective dates vary by product with the 2018 RCW signed on July 28, 2019.[26]
- **City of Shoreline Ordinance No. 948**. The "Ordinance of the City of Shoreline, Washington Amending Chapter 15.05, Construction and Building Codes, of the Shoreline Municipal Code, to Provide Amendments to the WSEC – Commercial, as Adopted by the State of Washington" adds a new section to Seattle Municipal Code 15.05 adopting the WSEC, as adopted by the Building Council in Chapter 51-11 of the Washington Administrative Code with amendments addressing reductions of carbon emissions in new commercial construction. The ordinance took effect on July 1, 2022.
- **City of Bellingham Ordinance.** The "Ordinance of the City of Bellingham Amending Bellingham Municipal Code Chapter 17.10 – Building Codes, to Provide Amendments to the WSEC – Commercial, Promoting Energy Efficiency and the Decarbonization of Commercial and Large Multifamily Buildings and Requiring Solar Readiness for New Buildings" took effect on August 7, 2022.

The following policy driven initiatives (Seattle's Energy Benchmarking program and the Clean Buildings Bill) do not mandate an energy code or baseline for specific measures, rather they inherently speed up the rate of the adoption of energy efficiency through energy reduction requirements. PSE can also claim energy impacts through these initiatives; therefore, removing measures or adjusting baselines may not be appropriate within the context of the CPA. Since PSE already incorporates a 10-year ramp rate for most discretionary measures, this accelerated adoption essentially accounts for the majority of these initiatives.

- **Seattle's Energy Benchmarking Program (SMC 22.920).** This program requires owners of commercial and multifamily buildings (20,000 square feet or larger) to track and annually report energy performance to the city of Seattle. Though in effect since 2016, full enforcement of the program began on January 1, 2021.[27]
- **Clean Buildings Bill (E3SHB 1257).** The law requires the Washington State Department of Commerce to develop and implement an energy performance standard for the state's existing buildings, especially large commercial buildings (based on building square feet) and provide

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[26] Washington State Legislature, Revised Code of Washington. December 7, 2020. "RCW 19.260.050 Limit on Sale or Installation of Products Required to Meet or Exceed Standards in RCW 19.260.040." https://app.leg.wa.gov/rcw/default.aspx?cite=19.260.050

[27] City of Seattle, Office of Sustainability and Environment. Accessed May 2022. "Energy Benchmarking." https://www.seattle.gov/environment/climate-change/buildings-and-energy/energy-benchmarking

incentives to encourage efficiency improvements. The effective date was July 28, 2019, with the building compliance schedule set to begin on June 1, 2026. Early adopter incentive applications began in July 2021.[28]

Treatment of Federal Standards

Cadmus explicitly accounted for several other pending federal codes and standards. For the residential and commercial sectors, these included appliance, HVAC, and water-heating standards. Figure 36 provides a comprehensive list of equipment standards considered in the study. However, Cadmus did not attempt to predict how energy standards might change in the future. At the time of this study's development, the proposed federal natural gas residential furnace standard (effective in 2029) had not been public and this study did not account for this proposed future standard.

Figure 36. Natural Gas Federal and State Equipment Standards Considered

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	Federal standard 2013	Nonresidential	January 8, 2013
	Federal standard 2018		January 1, 2018
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dishwasher (commercial)	State standard 2019	Nonresidential	January 1, 2021
Dryer	Federal standard 2015	Residential	January 1, 2015
Boiler – Residential sized	Federal standard 2021	Nonresidential/Residential	January 15, 2021
Boiler – Commercial sized	Federal standard 2023	Nonresidential	January 10, 2023
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/Residential	January 1, 2021
Water Heater >55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015
Water Heater ≤55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015

Additional Codes and Standards Considerations

Cadmus identified an additional consideration that impact the characterization of this potential study: residential and commercial new construction prescriptive and performance path requirement options, included in the 2018 WSEC. The CPA characterizes efficiency improvements on a measure basis that align with the prescriptive path. The performance path includes the HVAC total system performance ratio requirement, defined as the ratio of the sum of a building's annual heating and cooling load compared to the sum of the annual carbon emissions from the energy consumption of the building's HVAC systems. The variability in the HVAC total system performance ratio from building to building cannot be easily captured in the CPA. For this study, Cadmus followed the prescriptive requirements in the 2018 WSEC.

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28 Washington State Department of Commerce. Accessed July 2022. "Clean Buildings." https://www.commerce.wa.gov/growing-the-economy/energy/buildings/

Adapting Measures from PSE Business Cases and RTF and Draft *2021 Power Plan*

Cadmus prioritized PSE's program business cases in developing measure characterization inputs. In most cases, the program business cases relied on the RTF and Council workbooks tailored to PSE's territory and program delivery experience. In adapting ECMs for this study, Cadmus adhered to three principles:

- **PSE Developed Business Cases:** We used the PSE business cases as the primary data source for measure characterization inputs, where possible. Using these business cases creates better alignment between PSE program planning projections and potential estimates for applicable measures.
- **Deemed ECM savings in RTF or Council workbooks must be preserved:** PSE mainly relies on deemed savings estimates provided in RTF and Council workbooks. Therefore, Cadmus sought to preserve these deemed savings to avoid possible inconsistencies among estimates of potential, targets, and reported savings.
- **Use inputs specific to PSE's service territory:** Some RTF and Council workbooks relied on regional estimates of saturations, equipment characteristics, and building characteristics derived from the RBSA and CBSA. Cadmus updated regional inputs with estimates, calculated either from PSE's oversample of CBSA and RBSA or from estimates affecting the broader PSE area. This approach preserved consistency with Council methodologies while incorporating PSE-specific data.
- **Use the "Industrial Assessment Center Database":** Cadmus adapted industrial measures from the U.S. Department of Energy's "Industrial Assessment Center Database (2000–2021)" for inclusion in this study for measure savings (expressed as end-use percentage savings) and measure costs (expressed as dollars per therm saved). We sources industrial measure lifetimes (expressed in years) from technical reference manuals.

Baseline End-Use Load Forecast Development

Creating a baseline forecast required multiple data inputs to accurately characterize energy consumption in PSE's service area. These are PSE's sector-level sales and customer forecasts, customer segments (business, dwelling, or facility types), end-use saturations (percentage of an end use [such as a furnace] present in a building), equipment saturations (such as the average number of units in a building), fuel shares (proportion of units using electricity versus natural gas), efficiency shares (the percentage of equipment below, at, and above standard), and annual end-use consumption estimates by efficiency levels.

PSE's sector-level sales and customer forecasts provided the basis for assessing energy efficiency potential. Prior to estimating potential, Cadmus disaggregated sector-level load forecasts by customer segment, building vintage (existing structures and new construction), and end use (all applicable end uses in each customer sector and segment).

After the market segmentation, Cadmus mapped the appropriate end uses to relevant customer segments. Upon determining appropriate customer segments and end uses for each sector, Cadmus determined how many units of each end use would be found in a typical home. End-use saturations represent the average number of units in a home and fuel shares represent the proportion of those units using electricity versus natural gas. For example, on average, a typical home has 0.9 clothes dryers (the saturation), and 15% of these units are natural gas (the fuel share).[29] Efficiency shares equal the current saturation of a specific type of equipment (of varying efficiency). Within an end use, these shares sum to 100%.

Next, Cadmus calculated annual end-use consumption for each end use in each segment in the commercial and residential sectors using the following equation:

$$TEUC_{ij} = \sum ACCTS_i \times UPA_i \times SAT_{ij} \times FSH_{ij} \times ESH_{ije} \times EUI_{ije}$$

where:

$TEUC_{ij}$	=	The total energy consumption for end use j in customer segment i
$ACCTS_i$	=	The number of accounts/customers in customer segment i
UPA_i	=	The number of units per account in customer segment i (UPA_i generally equals the average square feet per customer in commercial segments and 1.0 in residential dwellings, assessed at the whole-home level)
SAT_{ij}	=	The share of customers in customer segment i with end use j
FSH_{ij}	=	The share of end use j of customer segment i served by natural gas
ESH_{ije}	=	The market share of efficiency level in equipment for customer segment i and end use j
EUI_{ije}	=	The end-use intensity, or energy consumption per unit (per square foot for commercial and 1.0 for residential) for the natural gas equipment configuration ije

For each sector, we determined the total annual consumption as the sum of $TEUC_{ij}$ across the end uses, j, and customer segments, i.

Consistent with other conservation potential studies, and commensurate with industrial end-use consumption data, we allocated the industrial sector's loads to end uses in various segments based on the *Manufacturing Energy Consumption Survey* data available from the U.S. Energy Information Administration.[30]

Derivation of End-Use Consumption

End-use energy consumption estimates by segment, end use, and efficiency level (EUI_{ije}) provided one of the most important components in developing a baseline forecast. In the residential sector, Cadmus used estimates of unit energy consumption, representing annual energy consumption associated with

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29 Saturations are less than 1.0 when some homes do not have the end use.

30 U.S. Department of Energy, Energy Information Administration. 2018. *Manufacturing Energy Consumption Survey.*

an end use and represented by a specific type of equipment. We derived the basis for the unit energy consumption values from savings in the PSE business cases, most recent RTF UES workbooks, and the Council's draft *2021 Power Plan* workbooks and savings analysis to calculate accurate consumption wherever possible for all efficiency levels of an end-use technology. When PSE business cases and RTF and Council workbooks did not exist for certain end uses, Cadmus used results from NEEA's 2018 RBSA PSE oversample, including RBSA public data for the same heating and cooling zone as PSE's territory, or we conducted additional research.

For the commercial sector, Cadmus treated consumption estimates as end-use intensities that represented annual energy consumption per square foot served. To develop the end-use intensities, Cadmus developed electric energy intensities (total therms per building square foot) based on NEEA's 2019 CBSA (CBSA IV), based on PSE oversample and public data. Cadmus then benchmarked these electric energy intensities against various other data sources including the CBSA III, historical forecasted and potential study data from PSE, and historical end-use intensities developed by the Council and NEEA.

For the industrial sector, end-use energy consumption represented total annual industry consumption by end use, as allocated by the secondary data described above.

PSE Forecast Climate Change Alignment

Cadmus worked with the PSE load forecast team to adjust the residential and commercial baseline forecast to account for climate change impacts. First we characterized the heating end-use consumptions using climate change adjustment factors based Council data (from TMY to Council-projected FMY) for any non-Council weather-sensitive RTF and PSE business case measures. For example, we based natural gas furnace end-use consumptions on PSE measure business case estimates, adjusted using HVAC FMY to TMY ratios from Council-developed building simulations, as shown in Table 22.

Table 22. Residential Council Modeled HVAC FMY to TMY Ratio

Council Modeled Ratios	HVAC Ratio (FMY/TMY)
All Residential Heating – Heating Zone 1	0.80

The resulting heating end-use consumption presents the upper bound of the climate adjustment (final year estimate). Next, we calibrated the annual change in residential and commercial heating end-use consumption with PSE's climate impacts within annual load forecasts to reflect climate change over the course of the study (where climate impacts increase over time). We followed a similar process to determine the climate impacts for the commercial heating end use.

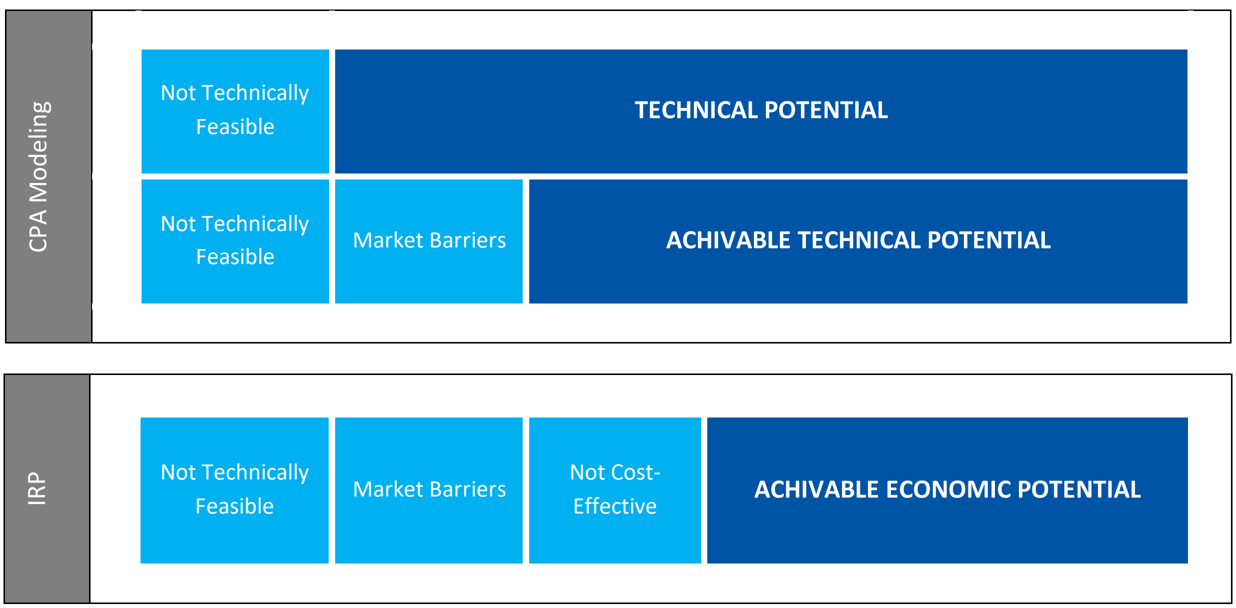
Conservation Potential Estimation

Cadmus estimated two types of conservation potential, and PSE determined a third potential—achievable economic—through the IRP's optimization modeling, as shown in Figure 37:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total energy efficiency potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential assumed to be achievable during the study forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical potential determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on costs and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which PSE then entered as variables in the IRP's optimization model to determine achievable economic potential. The following sections describe Cadmus' approach for estimating technical and achievable technical potential.

Figure 37. Types of Energy Efficiency Potential



Technical Potential

Technical potential includes all technically feasible ECMs, regardless of costs or market barriers. Technical potential divides into two classes: discretionary (retrofit) and lost opportunity (new construction and replacement of equipment on burnout).

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization, shell upgrades, and low-flow showerheads.
- ***Lost opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include furnaces, water heaters, and appliances.

Another important aspect in assessing technical potential is, wherever possible, to assume installations of the highest-efficiency equipment that are commercially available. For example, there are two tiers of natural gas furnaces: 94% AFUE furnace and 96% AFUE furnace in residential applications. To assess technical potential, we assumed that, as equipment fails or new homes are built, customers will install 96% AFUE furnace wherever technically feasible, regardless of cost. Where applicable, we assumed that 94% AFUE furnace would be installed in homes ineligible for 96% AFUE furnace. Cadmus treated competing non-equipment measures in the same way, assuming installation of the highest-saving measures where technically feasible.

In estimating technical potential, it is inappropriate to merely sum savings from individual measure installations. Significant interactive effects can result from installations of complementary measures. For example, upgrading a furnace in a home where insulation measures have already been installed can produce less savings than upgrades in an uninsulated home. Our analysis of technical potential accounts for two types of interactions:

- ***Interactions between equipment (lost opportunity) and non-equipment (discretionary or retrofit) measures:*** As equipment burns out, technical potential is based on assuming that equipment will be replaced with higher-efficiency equipment, reducing average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have if the equipment had remained at a constant average efficiency. Similarly, savings realized by replacing equipment decrease upon installation of non-equipment measures.
- ***Interactions between two or more non-equipment (discretionary or retrofit) measures:*** Two non-equipment measures that apply to the same end use may not affect each other's savings. For example, installing a low-flow showerhead does not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, causes water heaters to operate more efficiently, thus reducing savings from those water heaters. Cadmus accounted for such interactions by stacking interactive measures, iteratively reducing the baseline consumption as measures are installed, thus lowering savings from subsequent measures.

Although, theoretically, all retrofit opportunities in existing construction—often called discretionary resources—could be acquired in the study's first year, this would skew the potential for equipment measures and provide an inaccurate assessment of measure-level potential. Therefore, Cadmus assumed that these opportunities would be realized in equal annual amounts over the 27-year planning horizon. By applying this assumption, natural equipment turnover rates, and other adjustments described above, we could estimate the annual incremental and cumulative potential by sector, segment, construction vintage, end use, and measure.

Cadmus' technical potential estimates drew upon best-practice research methods and standard utility industry analytic techniques. Such techniques remained consistent with the conceptual approaches and methodologies used by other planning entities (such as by the Council in developing regional energy efficiency potential) and remained consistent with methods used in PSE's previous CPAs.

Achievable Technical Potential

The achievable technical potential summarized in this report is a subset of the technical potential that accounts for market barriers. To subset the technical potential, Cadmus followed the approach of the Council and employed two factors:

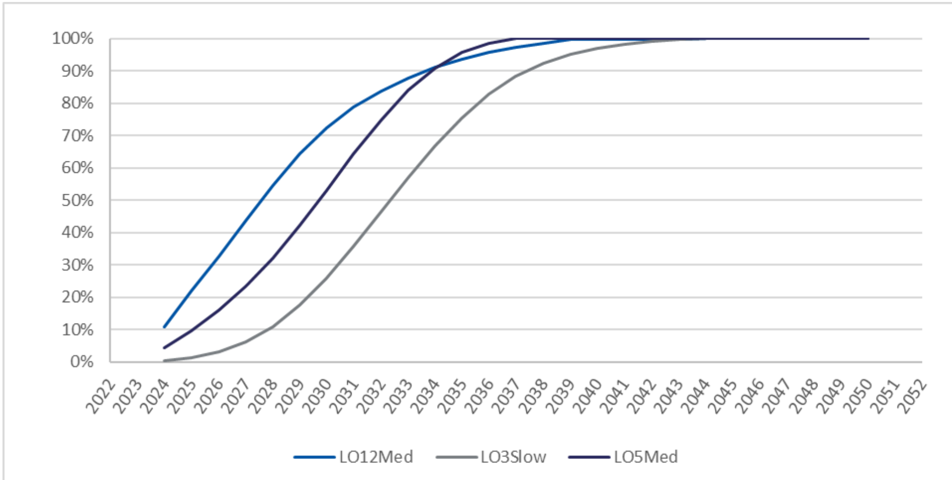
- **Maximum achievability factors** represent the maximum proportion of technical potential that can be acquired over the study horizon.
- **Ramp rates** are annual percentage values representing the proportion of cumulative 27-year technical potential that can be acquired in a given year (discretionary measures) or the proportion of technical annual potential that can be acquired in a given year (lost opportunity measures).

Achievable technical potential is the product of technical potential and both the maximum achievability factor and the ramp rate percentage. Cadmus assigned maximum achievability factors to measures based on the Council's draft *2021 Power Plan* supply curves. Ramp rates are measure-specific and we based these on the ramp rates developed for the Council's draft *2021 Power Plan* supply curves, adjusted to account for the 2024 to 2050 study horizon.

For most discretionary measures, Cadmus assumed that savings are acquired at an even rate over the first 10 years of the study. In other words, achievable technical potential for discretionary measures equals one-tenth of the total cumulative achievable technical potential in each of the first 10 years of the study (2024 through 2033). After 2033, most of the additional potential comes from loss opportunity measures. There were a few exceptions where we applied a custom rate (longer than 10 years) to discretionary measures based on PSE program data (such as for cooking measures).

For lost opportunity measures, we used the same ramp rates as those developed by the Council for its draft *2021 Power Plan* supply curves. However, the draft *2021 Power Plan* ramp rates cover only the 2024 to 2043 period of this study's horizon. Because nearly all lost opportunity ramp rates approach 100%, we set ramp values for 2044 through 2050 to equal the 2043 value from the Council's draft *2021 Power Plan*. Figure 38 illustrates the lost opportunity ramp rates used for natural gas measures in this study.

Figure 38. Lost Opportunity Ramp Rates



Integrated Resource Plan Input Development

Cadmus developed energy efficiency supply curves to allow PSE's IRP optimization model to identify the cost-effective level of energy efficiency. PSE's optimization model required monthly forecasts of natural gas energy efficiency potential. To produce these monthly forecasts, we applied 8760-hour end-use load shapes to annual estimates of achievable technical potential for each measure. These hourly end-use load profiles are generally the same as those used by the Council in its draft *2021 Power Plan* supply curves and by the RTF in its UES measure workbooks (including generalized shapes that we expanded to hourly shapes).

Cadmus worked with PSE to determine the format of inputs into the IRP model. We grouped energy efficiency potential into the levelized costs bundles shown in Table 23. The number and delineating values of the levelized cost bundles has changed from the 2021 CPA. While there were 12 bundles in 2021 CPA, this CPA has 18 bundles.

Table 23. Natural Gas Levelized Cost Bundles

Bundle	Natural Gas Bundle ($/therm)
1	($999,999.00) to $0.22
2	$0.22 to $0.30
3	$0.30 to $0.45
4	$0.45 to $0.50
5	$0.50 to $0.55
6	$0.55 to $0.62
7	$0.62 to $0.70
8	$0.70 to $0.85
9	$0.85 to $0.95
10	$0.95 to $1.20
11	$1.20 to $1.50
12	$1.50 to $1.75
13	$1.75 to $2.00
14	$2.00 to $2.25
15	$2.25 to $2.50
16	$2.50 to $2.75
17	$2.75 to $3.00
18	$3.00 to $999,999.00

Cadmus derived the levelized cost for each measure using the following formula.

$$\text{Levelized cost of electricity (LCOE)} = \frac{\sum_{t=0}^{n} \frac{Expenses_t}{(1+i)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+i)^t}}$$

where:

LCOE = The levelized cost of conserved energy for a measure

n = The lifetime of the analysis (27 years)

$Expenses_t$ = All net expenses in the year *t* for a measure using the costs and benefits outlined in Table 24

i = The discount rate

E_t = The energy conserved in year *t*

Cadmus grouped the achievable technical potential by levelized cost over the 27-year study horizon, allowing PSE's IRP model to select the optimal amount of energy efficiency potential given various assumptions regarding future resource requirements and costs. The 27-year total resource levelized cost calculation incorporates numerous factors, which are consistent with the expense components shown in Table 24.

Table 24. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost [a]
	Administrative Adder
Benefits	Present Value of NEIs
	Conservation Credit
	Secondary Energy Benefits

[a] Some measures may have a reduction in O&M costs, which is a benefit in the levelized cost calculation.

Cadmus' approach for calculating a measure's levelized cost of conserved energy aligned with the Council's approach and incorporated several factors:

- ***Incremental measure cost.*** Cadmus considered the costs required to sustain savings over a 27-year horizon, including reinstallation costs for measures with EULs less than 27 years. If a measure's EUL extends beyond the end of the 27-year study, Cadmus incorporated an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 27-year period.[31]

  For example, Figure 39 shows the timing of initial and reinstallation costs for a measure with a 10-year lifetime in the context of the 27-year study horizon. The measure's final lifetime in this study ends after the study horizon, so the final seven years (Year 21 through Year 27) are treated differently by leveling measure costs over its 10-year EUL and treating these as annual reinstallation costs.

Figure 39. Illustration of Capital and Reinstallation Cost Treatment

	Year																										
Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Initial Capital Cost																											
Re-installation Cost																					End Effect						

- ***Incremental O&M benefits or costs.*** As with incremental measure costs, we considered O&M costs annually over the 27-year horizon. Cadmus used the present value to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 21% of incremental measure costs across all sectors.
- ***Non-energy impacts.*** We treated these impacts as a reduction in levelized costs for measures that save resources, such as water, or that provide other benefits to users or the utility. For example, the value of reduced water consumption due to the installation of a low-flow

31 In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%). Cadmus applied this method both to measures with an EUL of greater than 27 years and to measures with an EUL that extends beyond the study horizon at the time of reinstallation.

showerhead reduces the levelized cost of that measure. The details of how we accounted for the NEIs are outlined in the *Energy Efficiency Measure Characterization* section.

- ***The regional 10% conservation credit.*** The addition of this credit per the Northwest Power Act[32] is consistent with the Council's methodology and is effectively an adder to account for the unquantified external benefits of conservation when compared to other resources.
- ***Secondary energy benefits.*** We treated these benefits as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment was necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for R-60 ceiling insulation for a home with a natural gas furnace and an electric central cooling system. For the heating end use, Cadmus considered the energy savings that R-60 insulation produces for central cooling system, conditioned on the presence of gas heating, as a secondary benefit that reduces the levelized cost of the measure. This adjustment only impacts the measure's levelized costs: the magnitude of energy savings for the R-60 measure is not impacted by considering secondary energy benefits.

32 Northwest Power and Conservation Council. January 1, 2010. "Northwest Power Act." http://www.nwcouncil.org/library/poweract/default.htm

Glossary of Terms

Cadmus compiled these definitions mostly from the *National Action Plan for Energy Efficiency Guide for Conducting Energy Efficiency Potential Studies and the State and Local Energy Efficiency Action Network*.[33]

Achievable economic potential: The subset of achievable technical potential that is economically cost-effective compared to conventional supply-side energy resources.

Achievable technical potential: The amount of energy that efficiency can realistically be expected to displace.

Benefit/cost ratio: The ratio (as determined by the total resource cost test) of the discounted total benefits of the program to the discounted total costs over some specified time period.

Conservation potential assessment (CPA): A quantitative analysis of the amount of energy savings that exists, proves cost-effective, or could potentially be realized by implementing energy-efficient programs and policies.

Cost-effectiveness: A measure of relevant economic effects resulting from implementing an energy efficiency measure. If the benefits of this selection outweigh its costs, the measure is considered cost-effective.

End use: A category of equipment or service that consumes energy (such as lighting, refrigeration, heating, and process heat).

End-use consumption: Used for the residential sector, this represents per-UEC consumption for a given end use, expressed in annual kilowatt-hours per unit.

End-use intensities: Used in the C&I sectors, this is the energy consumption per square foot for a given end use, expressed in annual kilowatt-hours per square foot per unit.

Energy efficiency: The use of less energy to provide the same or an improved service level to an energy consumer in an economically efficient way.

Effective useful life (EUL): An estimate of the duration of savings from a measure. EUL is estimated through various means, including the median number of years that energy efficiency measures installed under a program remain in place and operable. EUL is also sometimes defined by the date at which 50% of installed units remain in place and operational.

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33 Schiller Consulting, Inc. (Schiller, Steven R.). 2012. *Energy Efficiency Program Impact Evaluation Guide. NAPEE Guide for Conducting Energy Efficiency Potential Studies and the State and Local Energy Efficiency Action Network.* www.seeaction.energy.gov

Levelized cost: The result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value), divided by the project's expected lifetime output (in megawatt-hours).

Lost opportunity: Refers to an efficiency measure or efficiency program seeking to encourage the selection of higher-efficiency equipment or building practices than that typically chosen at the time of a purchase or design decision.

Measure: Installation of equipment, subsystems, or systems, or modifications of equipment, subsystems, systems, or operations on the customer side of the meter, designed to improve energy efficiency.

Portfolio: Either (a) a collection of similar programs addressing the same market, technology, or mechanisms or (b) the set of all programs conducted by one organization.

Program: A group of projects with similar characteristics and installed in similar applications.

Retrofit: An efficiency measure or efficiency program intended to encourage the replacement of functional equipment before the end of its operating life with higher-efficiency units (also called early retirement) or the installation of additional controls, equipment, or materials in existing facilities for reducing energy consumption (such as increased insulation, lighting occupancy controls, and economizer ventilation systems).

Resource adequacy*:* Having sufficient resources, generation, energy efficiency, storage, and demand-side resources to serve loads across a wide range of conditions.

Technical potential: The theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints (such as cost-effectiveness or the willingness of end users to adopt the efficiency measures).

Total resource cost test: A cost-effectiveness test that assesses the impacts of a portfolio of energy efficiency initiatives on the economy at large. The test compares the present value of efficiency costs for all members of society (including costs to participants and program administrators) compared to the present value of benefits, including avoided energy supply and demand costs.

Utility cost test: A cost-effectiveness test that evaluates the impacts of efficiency initiatives on an administrator or an energy system. It compares administrator costs (such as incentives paid, staff labor, marketing, printing, data tracking, and reporting) to accrued benefits, including avoided energy and demand supply costs. Also called the program administrator cost test.

Appendix A. Heat Pump Market Research Findings

RESEARCH APPROACH

CADMUS

INTERVIEW APPROACH

Contractors	Builders
Research Objective: Understand contractor perspectives on heat pump sales by system type, attitudes towards cold climate heat pumps, and barriers to electrification	**Research Objective:** Understand builder perspectives on heat pumps in all-electric and dual-fuel homes, market trends, and customer interest
Completed 12 contractor interviews Installed a total of 3,021 HVAC systems (2,801 heat pumps) in existing single-family homes within PSE's service territory in the last 12 months	**Completed 2 builder interviews** Built a total of 20 new, single-family homes in PSE's service territory in the last 12 months (30% all-electric, 70% electric and gas connected homes)

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INTERVIEW APPROACH

Category	Total Contacted	Targeted Completes	Achieved Completes
Contractors	83	≤ 15	12
Builders	38	≤ 5	2
Total	**121**	**≤ 20**	**14**

Response Rate by Contact Mode

Phone Call

7% response rate

Email

13% response rate

Response Rate by Category

Contractors	14%
Builders	5%

Eligibility

HVAC contractors that have installed heat pumps in PSE service territory

Builders that have developed new homes using heat pumps around PSE service territory

Incentive

$150 Amazon gift card to each interviewed contractor and builder

SURVEY APPROACH

Completed **862** online surveys with eligible PSE customers

5 winners selected for a $100 Amazon gift card

- Gas-only or combination PSE customers
- Homeowners with gas as primary heating fuel
- Familiarity with air source heat pumps

Research Objectives

- Assess general awareness of and interest in heat pump technology
- Understand barriers and opportunities for adoption
- Measure willingness to purchase heat pumps among gas-heated homes (market demand)

SURVEY APPROACH

5 Willingness-to-Pay Scenarios	Baseline Equipment
Ductless Replace On Burn-out: Full Electrification	Ductless gas heat, Cooling or no cooling
Ductless Partial Displacement: DHP with Existing Gas Backup	Ductless gas heat, Cooling or no cooling
Ducted Replace on Burnout: Full Electric	Gas furnace, Cooling or no cooling
Ducted Hybrid (Dual-Fuel) Heat Pump Retrofit – Added Cooling	Gas furnace, No central cooling
Ducted Replace on Burnout: Hybrid Heat Pump	Gas furnace, Central cooling

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SURVEY APPROACH

Housing Strata	Total Contacted	Targeted Completes	Achieved Completes
Multifamily	9,179	200	135
Single Family	34,768	200	579
Low-Income	27,719	200	148
Total	**71,666**	**600**	**862**

Response Rate by Contact Mode

Postcard	Email
4% response rate	6% response rate

Response Rate by Housing Strata

Multifamily	4%
Single Family	11%
Low-Income*	3%

*200% below Federal Poverty Level

*Response rate includes partial responses.

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CUSTOMER SURVEY

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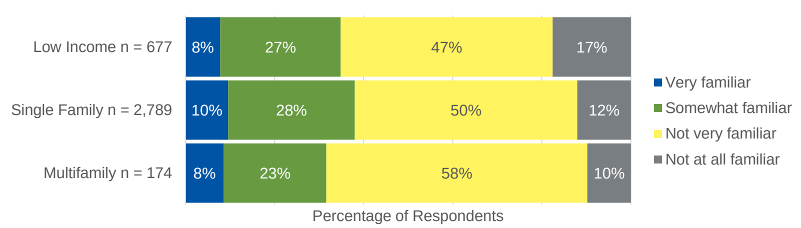
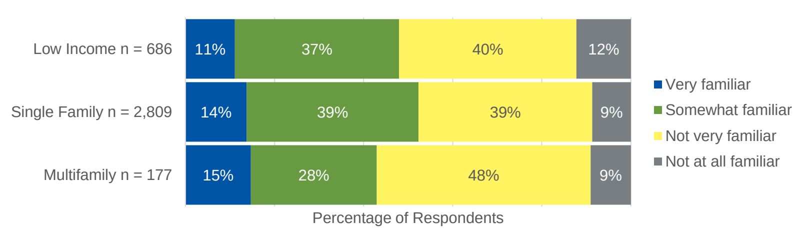
HEAT PUMP ATTITUDES AND AWARENESS

PSE customers are more familiar with ducted air source heat pumps compared to ductless

Ductless Air Source Heat Pump Awareness



Ducted Air Source Heat Pump Awareness



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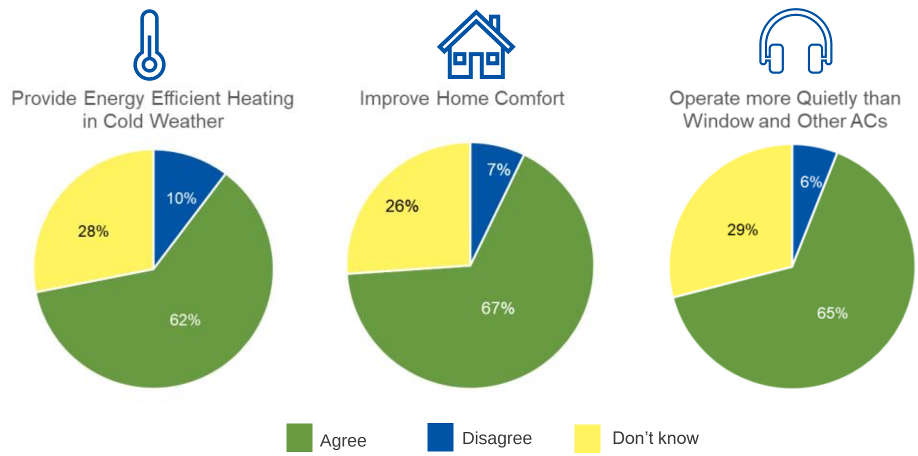
HEAT PUMP ATTITUDES AND AWARENESS

The majority of respondents agreed that performance, comfort, and noise reduction are benefits of air source heat pumps

AIR SOURCE HEAT PUMPS OF ANY TYPE CAN…



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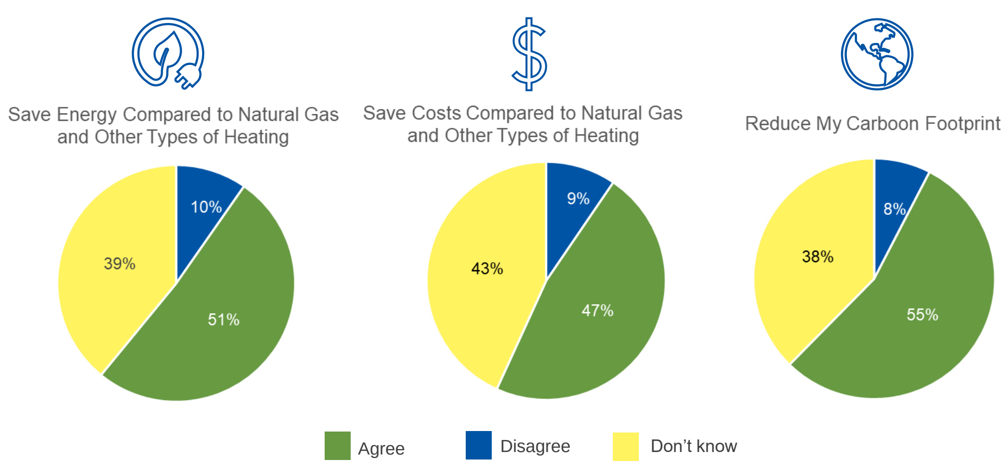
HEAT PUMP ATTITUDES AND AWARENESS

Respondents were much less sure about energy saving, cost saving, and climate benefits

AIR SOURCE HEAT PUMPS OF ANY TYPE CAN…



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HEAT PUMP ATTITUDES AND AWARENESS

Barrier Statements *Air source heat pumps…*	% Having Heard About Barrier			
	Overall	Multifamily	Single Family	Low-Income
Might have difficulty keeping a home warm enough in a Washington winter without a backup heating source	14%	10%	15%	12%
Might cost more to install than other heating or cooling equipment	14%	10%	14%	12%
Might disrupt the aesthetic of a room with wall-mounted indoor units	9%	10%	9%	8%
Might cost more to run than a traditional heating/cooling system	7%	6%	7%	7%
Might be more complicated to operate than a traditional heating/cooling system	6%	5%	6%	4%

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WILLINGNESS TO PAY

Ductless HP

SCENARIO SUMMARY	INCREMENTAL COST
Replace On Burn-out: Full Electrification	
1. Your current primary heating system is about to fail. A new ductless heat pump with 4 indoor units would provide efficient heating and cooling to your whole home without requiring ductwork. $150/year in energy bill savings.	$4,000
Partial Displacement: DHP with Existing Gas Backup	
2. Your current primary heating system is working. A new ductless heat pump with 3 indoor units would add cooling, improve comfort, and provide most of your heating. $100/year in energy bill savings.	$10,000

Note: Ductless respondents answered both scenarios, regardless of existing cooling.

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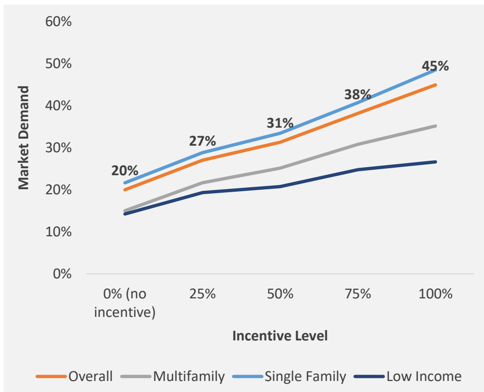
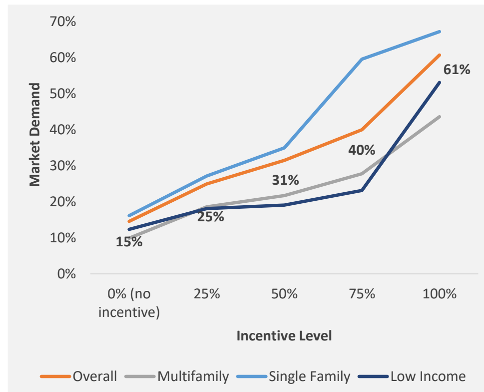
WILLINGNESS TO PAY

Ductless HP

SCENARIO 1
Replace On Burn-out: Full Electrification



SCENARIO 2
Partial Displacement: DHP with Existing Gas Backup



Note: Data labels represent "Overall" market demand (orange curve)

WHY NOT INSTALL?

Replace on Burn-out: Full Electrification

SINGLE FAMILY

- Concerned about how the DHP would look in my home (43%)
- Initial costs too high (35%)

LOW-INCOME

- Initial costs too high (40%)
- Don't believe monthly energy bill would go down (40%)
- Don't plan to stay in home long enough (25%)
- Would rather trust a technology I'm more familiar with (25%)

MULTIFAMILY

- Concerned about how the DHP would look in my home (29%)
- Don't plan to stay in home long enough (29%)
- Building restrictions such as HOAs (24%)

Partial Displacement: DHP with Existing Gas Backup

ALL HOUSING TYPES

- Satisfied with my current systems and do not need to supplement my heating or cooling with a DHP
- Other top reasons similar to ROB

WILLINGNESS TO PAY

Ducted HP

SCENARIO SUMMARY	INCREMENTAL COST
Replace on Burnout: Full Electric	
1. Your current primary heating system is <u>about to fail</u>. A new heat pump would use your existing ductwork and provide efficient heating and cooling to your whole home. $150/year in energy bill savings.	$4,500
Hybrid Heat Pump Retrofit – Added Cooling	
2. Your current primary heating system <u>is working</u>. A new heat pump would add cooling and operate in place of your furnace until the temperature reached around 35 degrees Fahrenheit and add central cooling. $100/year in energy bill savings.	$8,000
Replace on Burnout: Hybrid Heat Pump	
3. Your current heating system and cooling system are <u>both about to fail.</u> A new heat pump with natural gas back-up heat would provide efficient heating and cooling to your whole home. $100/year in energy bill savings.	$1,200

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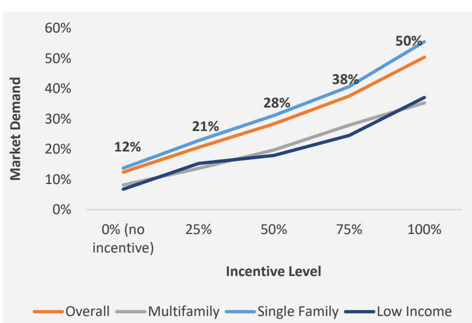
WILLINGNESS TO PAY

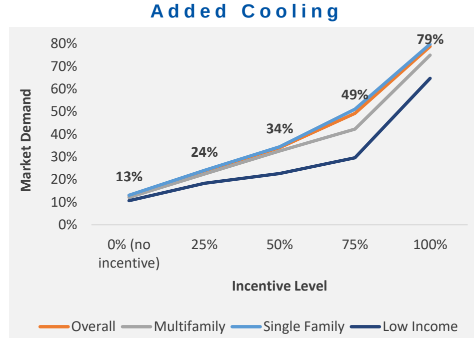
Ducted HP

SCENARIO 1
Replace on Burnout: Full Electric



Presented to anyone regardless of cooling.

SCENARIO 2
Hybrid Heat Pump Retrofit – Added Cooling



Presented to respondents without central cooling. Emphasized added cooling and back-up heat at 35°

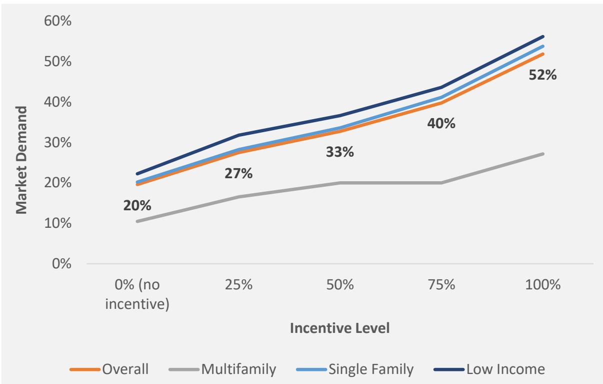
Note: Data labels represent "Overall" market demand (orange curve)

18 CADMUS

WILLINGNESS TO PAY

Ducted HP

SCENARIO 3
Replace on Burnout: Hybrid Heat Pump



Heating and cooling system failure and replacement with a hybrid system. Presented to respondents with central cooling.

Why is MF curve so low?

Only 11 MF customers responded to Scenario 3

5 of them would not install at all, reasons being:

- Building restrictions such as HOAs (2)
- Initial costs too high (1)
- Recently upgraded their system (1)
- Did not feel it was realistic to consider both systems failing at once (1)

Note: Data labels represent “Overall” market demand (orange curve)

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WILLINGNESS TO PAY

Incentives

Most “bang for the buck” (highest market share per dollar) is at 25% incentive tier

- 1:1 ratio. On average, 25% of respondents would participate if 25% of incremental costs are covered (In any situation)
- Ratio shrinks as incentive tiers grows (not a linear relationship)
- Market share gains at each tier are highest for hybrid or partial displacement scenarios

Average Increase in Market Share Per Incentive Tier

Hybrid / Partial Displacement

Jump in Market Demand

12%

Incentive Tier Increase

Full Electric

Jump in Market Demand

8%

Incentive Tier Increase

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WHY NOT INSTALL?

Replace on Burn-out: Full Electric

SINGLE FAMILY

- Initial costs too high (34%)
- Don't believe monthly energy bill would go down (29%)

LOW-INCOME

- Don't believe monthly energy bill would go down (32%)
- Initial costs too high (26%)

MULTIFAMILY

- Don't plan to stay in home long enough (28%)
- Building restrictions such as HOAs (28%)

Hybrid Heat Pump Retrofit

ALL HOUSING TYPES

- Satisfied with my current systems and do not need to supplement my heating or cooling with an ASHP
- Other top reasons similar to ROB

Replace on Burn-out: Hybrid

SINGLE FAMILY

- Initial costs too high (31%)
- Don't believe monthly energy bill would go down (40%)
- **Concerns about performance (26%)**

LOW-INCOME

- Don't believe monthly energy bill would go down (57%)
- **Concerns about performance (43%)**
- **Unsure of how to apply for incentives (43%)**

MULTIFAMILY

- Building restrictions such as HOAs (40%)

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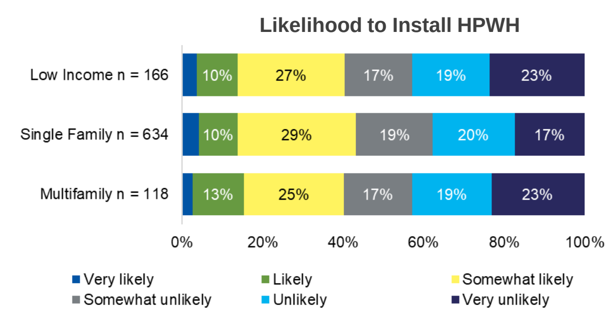
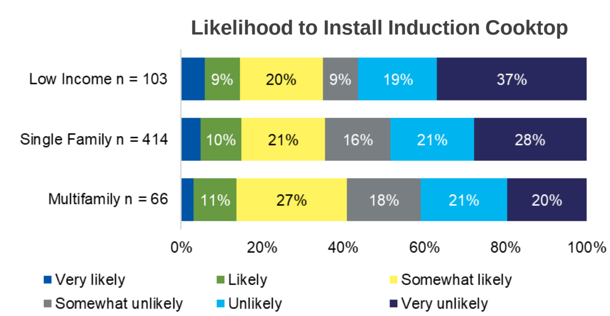
OTHER LOW-CARBON TECHNOLOGY



Most customers are "somewhat likely" to install a heat pump water heater if their current system needs replacement in the next two years.

Market Demand: 16%



Customers are slightly less likely to install an induction cooktop than a HPWH if their current system needs replacement in the next two years.

Market Demand: 14%

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CONTRACTOR AND BUILDER INTERVIEWS

HEAT PUMP INCREMENTAL COSTS

Incremental costs of heat pumps range from 7-17% of the combined cost of a gas heating system and central AC

Appliance	Avg Cost per Unit	Incremental Cost
Gas Furnace + Central AC	$13,830	-
Ductless Heat Pump	$15,223	$1,393
Ducted Heat Pump	$14,800	$970
Ducted Heat Pump + Gas Furnace (Hybrid/Dual-Fuel)	$16,250	$2,420

**Avg Central AC and Dual Fuel Heat Pump capacities were reported at 2.79 tons*
***Avg Ductless and Ducted Heat Pump capacities were reported at 2.94 tons*
****Many applications for each baseline and measure combination (e.g. replace on burnout, partial displacement retrofit, new construction, etc.) were integrated into the potential analysis. System and incremental costs provided are intended to be illustrative for one set of replace on burnout scenarios analyzed. Full dataset will be used for the CPA.*

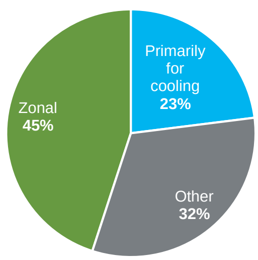
Incremental costs for ENERGY STAR, dual stage, and cold climate equipment ranged from 9%-50%. Half of contractors noted they only install ENERGY STAR ductless heat pumps

Contractors estimated that installing central AC for the first time added nearly $1,400 to the cost of the installation

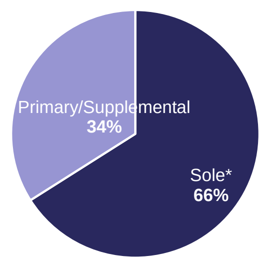
HEAT PUMP APPLICATIONS AND USAGE

Contractors surveyed installed 1,095 ductless heat pumps and 1,706 ducted heat pumps in the past 12 months.

Ductless Intent of Installation

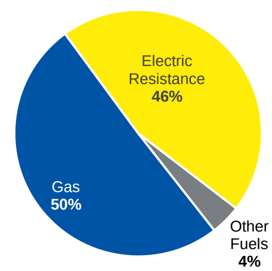


Ductless Applications



Prior Home Heating Type

(Ducted & Ductless)



Contractors considered ductless installations in zonal applications (e.g. new additions, previously-unheated spaces) as sole source installations. These buildings may have a separate heating system for the remainder of the home. Contractors reported a ductless heat pump as primary/supplemental or sole based primarily on whether there was another heating system present in the space the unit was installed in (whether one zone or the whole home).

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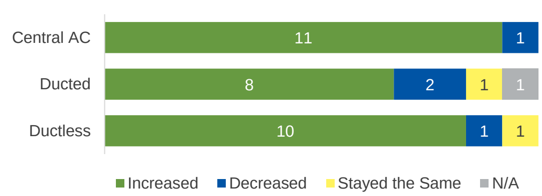
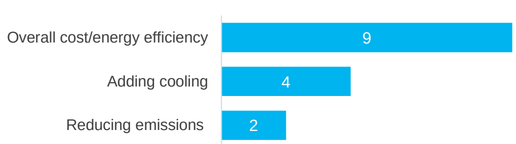
CUSTOMER INTEREST IN HEAT PUMPS AND CENTRAL AC

While energy efficiency and the COVID-19 pandemic have encouraged increasing installations of heat pumps, contractors also reported a significant increase in customers installing central AC for the first time due to recent heat waves

Change in Number of Installations in Past Year Relative to Previous Year



Key Customer Drivers for Heat Pump Installations



2 of 12 contractors differentiated between standalone and hybrid/dual-fuel ducted heat pumps, both saying that hybrid/ dual-fuel installations increased less than standalone systems, while others reported no difference

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COVID-19 IMPACTS ON HEAT PUMP INSTALLATIONS AND INTEREST

How COVID-19 impacted installations of ducted heat pumps	How COVID-19 impacted installations of ductless heat pumps
4 of 12 contractors reported challenging supply chain issues	**6 of 12** contractors reported challenging supply chain issues
5 of 12 contractors reported increased installations due to higher rates of working from home, customers wanting higher comfort levels, and increased interest in secure air filtration systems	**5 of 12** contractors reported increased installations due to higher rates of working from home and customers wanting higher levels of comfort

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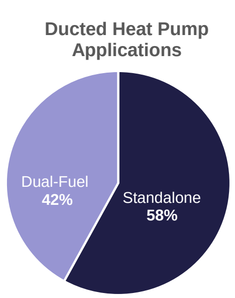
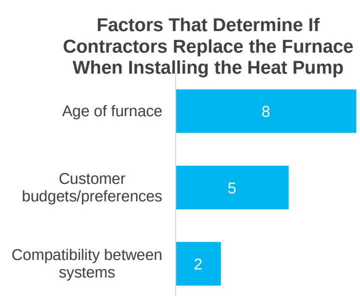
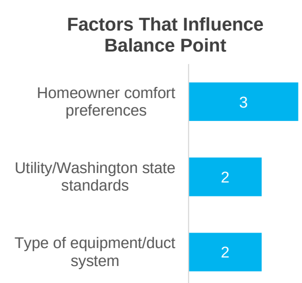
HYBRID/DUAL-FUEL HEAT PUMP CONFIGURATION

Most contractors reported replacing the furnace when installing ducted HPs in dual-fuel configurations, which increases the overall project cost.

A large majority stated that they use pre-set numbers or balance point calculators to determine **switchover temperatures between the furnace and the heat pump**. One contractor noted that newer systems can sense switchover temperatures using controls.







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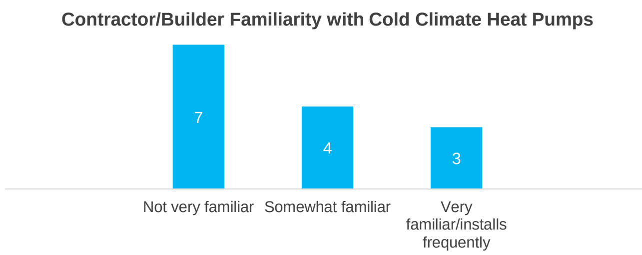
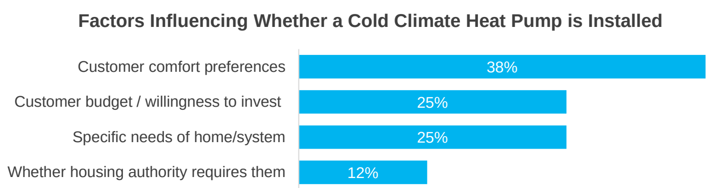
ATTITUDES AND AWARENESS OF COLD CLIMATE HEAT PUMPS

Contractors ranged widely in frequency of installation of cold climate ASHPs; contractors that don't typically install cold climate heat pumps stated the weather in their area is not cold enough to justify doing so





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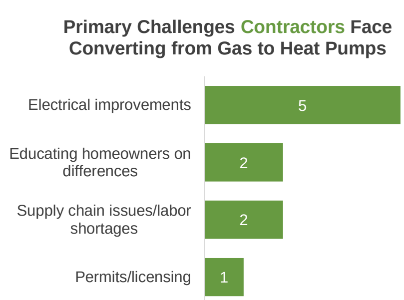
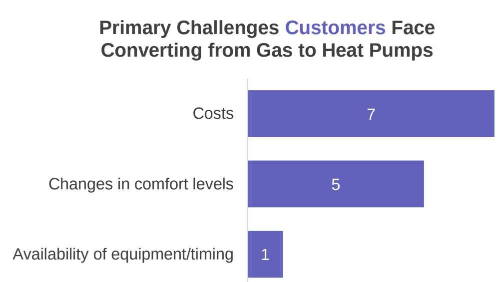
FUEL CONVERSION CHALLENGES

Contractors reported that electrical improvements are the greatest challenge when installing heat pumps in previously gas-heated homes, with **minor improvements needed over 50% of the time** (i.e., wiring and conduit). More **significant improvements are needed approximately 10% of the time** (i.e., panel or 200-amp electrical service upgrades).





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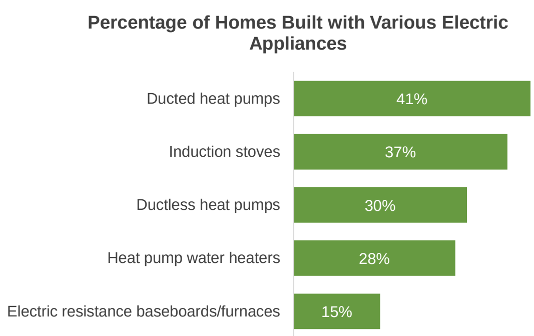
BUILDER INTERVIEW HIGHLIGHTS

The primary factors that make builders more likely to choose a heat pump for a new home include the overall energy package/energy efficiency of the new home and building code changes



Homebuyer interest in all-electric vs. electric & gas homes

"Clients are shifting towards all-electric for environmental reasons"

"It's mostly client-driven; it's a combination of cost-effectiveness and a lot of people shying away from natural gas"

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KEY RESEARCH TAKEAWAYS

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KEY FINDINGS SUMMARY

Customer demand for heat pumps is increasing, with a similar number of heat pumps being installed in gas-heated and electric-heated homes

- Demand for central AC is also increasing but contractors do not see this as a primary driver for customers' heat pump demand
- Some contractors noted that hybrid heat pumps were not growing as rapidly as ASHP-only installations, though others did not see a significant difference.
- The COVID-19 pandemic increased demand for heat pumps, though supply chain issues have constrained growth
- Most contractors are not familiar with or do not see the need for cold climate heat pumps in WA

While heat pump installations often have modest incremental costs compared to baseline equipment, additional costs may constrain market adoption

- Many gas homes require at least minor electrical improvements when converting to all-electric; high costs are a primary barrier to adoption.

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KEY FINDINGS SUMMARY

Market demand for hybrid replacements or partial displacement is higher than full electric HPs (at almost every incentive level). Added cooling is important.

- Maximum adoption scenario: 79% for hybrid heat pump retrofit on an existing gas furnace for customers without existing central cooling
- Optimal Incentive Level for any scenario: 25% of incremental cost
- Market demand is higher at the same incentives tiers for replace on burnout for a ducted hybrid system compared to a full electric HP*

*At tiers ≤50% of incremental cost

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KEY FINDINGS SUMMARY

Despite higher market demand for hybrid/dual-fuel, more people surfaced performance concerns when asked why they would not install a hybrid/dual-fuel (ducted) system

Other barriers to installation:

- “Happy with current system”
- Cost concerns (both initial and ongoing energy costs)

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NEXT STEPS

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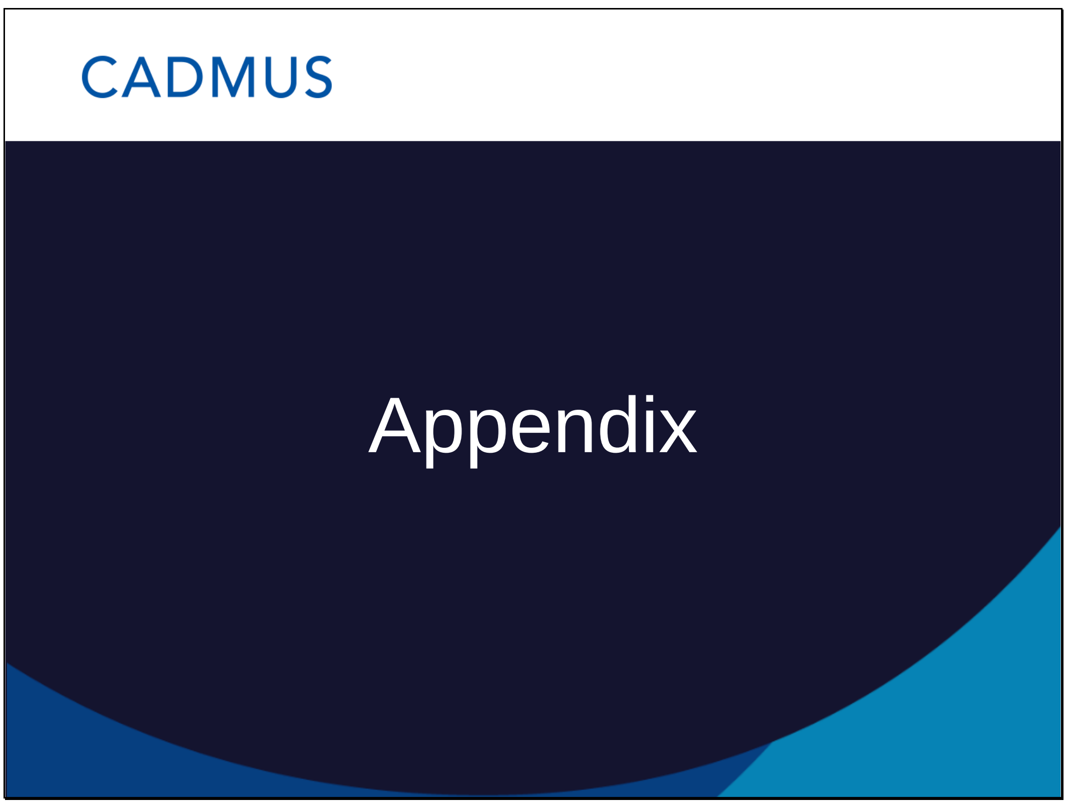
Thank You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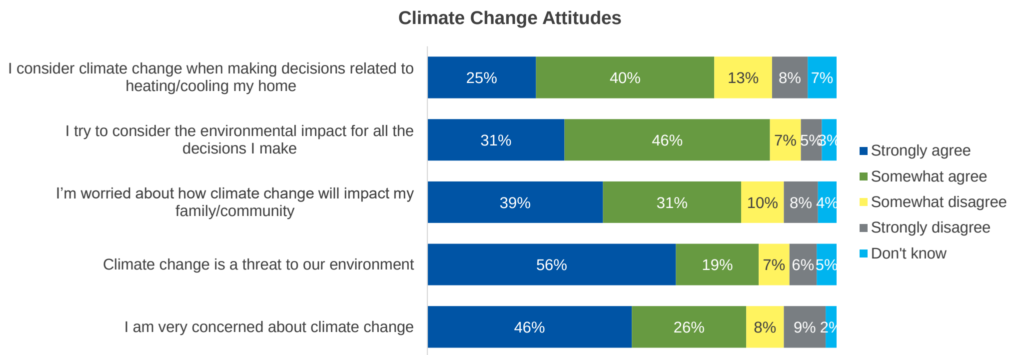
Appendix

CLIMATE CHANGE ATTITUDES

In many cases, there was a positive correlation between a customer's climate change attitudes and their willingness to install an ASHP with no utility incentive



Statements positively correlated with "very likely" to install:

- *I consider climate change when making decisions related to heating/cooling my home*
- *I am very concerned about climate change*

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Appendix B. Residential Heat Pump Adoption Survey

Cadmus will program the survey into an online format using the Qualtrics platform. The table below presents the research objectives and the corresponding survey questions.

Research Objectives	Corresponding Question Numbers
Establish and screen for baseline conditions of space heating and space cooling equipment	A1–A9
Gauge consumer awareness of air source heat pump technologies, benefits and perceived challenges	B1–B8
Identify barriers to installing heat pumps among homeowners upgrading their systems	C1–C5
Quantify consumers' willingness to purchase air source heat pumps at varying price points	D1–E18
Identify customers' willingness to adopt other low-carbon technology	F1–F4
Understand customers' attitudes about climate change	G1
Gather demographic information and housing, system characteristics for respondents	H1–H9

Target Audience: Residential gas heat homeowners within PSE's service territory in Washington who have familiarity with heat pump technology.

Expected number of completions: 600 total: 200 Gas Heat single-family homeowners (≥ 200% FPL), 200 Gas Heat multifamily homeowners (≥ 200% FPL), 200 Gas Heat homeowners (≤ 200% FPL).

Estimated timeline for fielding: 10 to 15 minutes

Survey and Sampling Design

- NOTE: Respondents will not answer all questions in this survey
- Survey recruitment will be through email and postcard distributions. Postcards will be sent out to customers who have a Digital Engagement Score of 0 or 1. Email invitations will be sent to customers who have a Digital Engagement Score of 2–10.

Variables to be pulled into Survey

- FIRSTNAME
- LASTNAME
- EMAIL
- DIGITAL ENGAGMENT SCORE

Survey Introduction and Screener

Welcome! Thank you for participating in this survey for Puget Sound Energy about your heating and cooling system. If you qualify and finish the survey, you will be eligible to enter a raffle for a chance to win a $100 Visa gift card. Please be sure to enter your contact information at the end of the survey. This survey is for research purposes only; it is not to sell a product of any kind. Please note that not all respondents will be eligible to complete the study.

If you'd like to pause your survey and come back to it at any time, simply close out of the survey, re-click on the link in your email, and pick up where you left off.

Open drop-down menus by clicking on this icon ▾ within the survey.

Click on the Next and Back buttons at the bottom of each page to navigate through the survey.

[SCREEN OUT TERMINATION MESSAGE:] Unfortunately, you don't qualify for this survey. Those are all the questions we have. Thank you.

A. Screener

To start, we have a few questions to confirm your eligibility for the survey.

A1. Do you own or rent your home?
1. Own
2. Rent [TERMINATE]

A2. What type of home do you live in?
1. Mobile or manufactured home
2. Single family detached house
3. Single family attached house such as a duplex, townhouse, or rowhouse
4. Apartment building or condominium building
5. Other [THANK AND TERMINATE]

A3. Do you have one or multiple sources of heating in your home? [SINGLE RESPONSE]
1. One
2. Multiple

A4. [IF A3=1] What is the type of fuel used for heating your home? [SINGLE RESPONSE]
1. Electricity [THANK AND TERMINATE]
2. Natural gas
3. Propane (bottled gas), fuel oil (delivered fuel), or kerosene (delivered fuel) [THANK AND TERMINATE]
4. District steam [THANK AND TERMINATE]
5. Wood/wood pellets [THANK AND TERMINATE]
98. Don't know [THANK AND TERMINATE]

A5. [IF A3=2] What is the primary type of fuel used for heating your home? [SINGLE RESPONSE]

1. Electricity [THANK AND TERMINATE]
2. Natural gas
3. Propane (bottled gas), fuel oil (delivered fuel), or kerosene (delivered fuel) [THANK AND TERMINATE]
4. District steam [THANK AND TERMINATE]
5. Wood/wood pellets [THANK AND TERMINATE]

98. Don't know [THANK AND TERMINATE]

A6. [IF A3=2] What is the supplementary type of fuel used for heating your home? [SINGLE RESPONSE]

1. Electricity
2. Natural gas
3. Propane (bottled gas), fuel oil (delivered fuel), or kerosene (delivered fuel)
4. District steam
5. Wood/wood pellets

98. Don't know

A7. What type of primary natural gas heating system do you have in your home? [SINGLE RESPONSE]

1. Central forced air furnace with vents in individual rooms
2. Steam/hot water system with radiators or baseboards in each room (central boiler)
3. Something else:_____________

A8. What type of equipment do you currently use for your home's primary cooling system? [SINGLE RESPONSE]

1. Central air conditioning system
2. Wall/room/window air conditioner unit(s)
3. Air source heat pump or ductless heat pump [THANK AND TERMINATE]
4. None
5. Ceiling or room fans
6. Something else:____________

A9. [IF A8=2,4, 5 or 6] Are you interested in installing central AC in the next two years?

1. Yes
2. No

98. Don't know

B. ASHP Awareness and Attitudes

B1. Prior to this survey, how familiar were you with ducted air source heat pumps, also called central air source heat pumps?

1. Very familiar [SKIP TO B3]
2. Somewhat familiar [SKIP TO B3]
3. Not very familiar
4. Not at all familiar
98. Don't know

B2. An electric ducted (or central) air source heat pump is a central heating and air conditioning system that uses electricity to transfer heat between your house and the outside air, providing heating in winter and cooling in the summer. It includes indoor and outdoor equipment and distributes heating and cooling into your home through ducts, similar to a central air conditioner and central furnace.

After this description, are you now familiar with ducted air source heat pumps?

1. Yes
2. No

B3. **Prior** to this survey, how familiar were you with **ductless** air source heat pumps, also called ductless mini-splits?

1. Very familiar [SKIP TO B5]
2. Somewhat familiar [SKIP TO B5]
3. Not very familiar
4. Not at all familiar
98. Don't know

B4. This is an electric ductless mini-split heat pump. Like a central ducted air source heat pump, a ductless heat pump uses electricity to provide both heating and cooling, however ductless heat pumps do not require ductwork to deliver heated or cooled air. Ductless systems consist of an outdoor unit and one or more indoor units. Indoor units are typically mounted high on a wall, which are connected to an outside unit which is typically installed next to the house.


After this description, are you now familiar with ductless air source heat pumps?

1. Yes
2. No

[IF B2=2 AND B4=2, THANK AND TERMINATE BECAUSE RESPONDENT NOT AWARE OF HEAT PUMPS]

Please rate your level of agreement with the following benefits of ducted and ductless air source heat pumps: [1=STRONGLY DISAGREE, 2=SOMEWHAT DISAGREE, 3=SOMEWHAT AGREE, 4=STRONGLY AGREE, 98=DON'T KNOW] [RANDOMIZE ORDER]

B5. Air source heat pumps of any type can…

1. Improve home comfort
2. Provide energy efficient heating in cold weather
3. Help reduce my carbon footprint
4. Operate more quietly than window and other air conditioners
5. Save energy compared to natural gas and other types of heating
6. Save costs compared to natural gas and other types of heating

B6. Have you ever heard of any challenges or drawbacks to air source heat pumps?

1. Yes
2. No

B7. [ASK IF B7=1] What challenges or drawbacks to air source heat pumps have you heard of? Please select all that apply. [RANDOMIZE ORDER OF 1–5]

1. Air source heat pumps might cost more to run than a traditional heating/cooling system.
2. Air source heat pumps might have difficulty keeping a home warm enough in a Washington winter without a backup heating source
3. Air source heat pumps might cost more to install than other heating or cooling equipment
4. Air source heat pumps might disrupt the aesthetic of a room with wall-mounted indoor units
5. Air source heat pumps might be more complicated to operate than a traditional heating/cooling system

B8. Please rate your level of agreement with the challenge: "[PIPE IN ANSWER FROM B6]" [1=STRONGLY DISAGREE, 2=SOMEWHAT DISAGREE, 3=SOMEWHAT AGREE, 4=STRONGLY AGREE, 98=DON'T KNOW]

[ASK FOR EACH SELECTED B6 THAT WAS 1–5]

C. HVAC System Upgrades and Barriers

Now, we'd like to talk more about your home's heating and cooling systems.

C1. Have you considered making improvements to your home's heating/cooling system (either a specific component or installing an entirely new system, including if your system failed) **in the past three years**? This would include if you've completed this work, it's in progress, or if you've considered it but haven't done any work.

1. Yes, I've considered or completed a whole system upgrade
2. Yes, I've considered or completed upgrading a specific component of the system
3. No [SKIP TO D1]

C2. [ASK IF C1=1 OR 2] You mentioned you've considered or made improvements to your home's heating/cooling system. Have you considered, or did you consider at any point, switching from a natural gas heating system to an electric air source heat pump?

1. Yes
2. No [SKIP TO D1]

C3. [ASK IF C2=1] Are you planning to install an air source heat pump?

1. Yes [SKIP TO D1]
2. No
3. Not sure [SKIP TO D1]

C4. [ASK IF C3=2] Which of the following are reasons why you considered, but decided not to install an air source heat pump? Please select all that apply. [RANDOMIZE ORDER OF 1–9]

1. The initial cost of an air source heat pump was too high (i.e. too expensive)
2. I didn't know enough about air source heat pumps

C5. I was concerned about the system's performance
1. I was concerned about the look of an air source heat pump installation
2. I don't plan to stay in home long enough for it to pay off
3. I went with a technology I was more familiar with
4. I didn't have enough time or resources to pursue upgrading my home's heating system at all
5. I was concerned that it would cost more on my monthly energy bill
6. I was concerned about switching to a different fuel source (i.e. switch to electric)
7. Something else, please specify [TEXT ENTRY BOX]

D. Willingness to Pay – Ductless Air Source Heat Pumps

[ONLY ASK SECTION D IF A7=2 AND B3=1 or 2, OR A7=2 AND B4=1]

Programming Note: Ductless heating system respondents are asked *both* Ductless ASHP Scenarios due to anticipated small population

The next section will ask you how likely you would be to install an electric ductless mini-split heat pump in your home. Some people install an electric ductless mini-split heat pump to provide more cost-effective and efficient heating and cooling than their current system, to add cooling, and/or to improve their comfort, for all or some areas of their home. As a reminder, this is not to sell you anything, this is for research purposes only.

[RANDOMZIE ORDER OF BLOCKS D1–D6 (Scenario 1) AND D7–D13 (Scenario 2)]

Scenario 1: Ductless ASHP – Full Replacement
Assume that you live in an 1,800 sq ft home and that **your current primary heating system is about to fail**. On average, installing a ductless mini-split heat pump to replace your current failing heating system would cost approximately $13,000—about $4,000 more than a new natural gas boiler. The system would have four indoor units, typically mounted up high on a wall like in the picture below and would provide heating and cooling to your whole home without requiring ductwork.

Switching to a ductless mini-split heat pump will decrease your gas bill while increasing your electric bill. Overall, you would save up to $150 a year on your energy costs. The system would also provide quiet, efficient heating and cooling throughout your home while being environmentally friendly and energy efficient.

D1. How likely would you be to install a ductless mini-split heat pump if your current primary heating system is about to fail and you received no utility incentive (i.e. paid the full cost out of pocket)? As a reminder, a ductless mini-split heat pump would cost about $4,000 more than a new natural gas boiler.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D2. [ASK IF D1=1–4] How likely would you be to install a ductless mini-split heat pump if you received an incentive of $1,000 from your utility (i.e. reduce the total installation cost by $1,000)? This would reduce the difference in cost between a ductless mini-split heat pump and a new natural gas boiler to about $3,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D3. [ASK IF D2=1–4] How likely you would be to install a ductless mini-split heat pump if you received an incentive of $2,000 from your utility (i.e. reduce the total installation cost by $2,000)? This would reduce the difference in cost between a ductless mini-split heat pump and a new natural gas boiler to about $2,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D4. [ASK IF D3=1–4] How likely you would be to install a ductless mini-split heat pump if you received an incentive of $3,000 from your utility (i.e. reduce the total installation cost by $3,000)? This would reduce the difference in cost between a ductless mini-split heat pump and a new natural gas boiler to about $1,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D5. [ASK IF D4=1–4] How likely you would be to install a ductless mini-split heat pump if you received an incentive of $4,000 from your utility (i.e. reduce the total installation cost by $4,000)? This would make the cost of installing a ductless mini-split heat pump about the same as a new natural gas boiler.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D6. [ASK IF D5=1–3] Why would you be unlikely to install a ductless mini-split heat pump if your gas heating system failed? Please select all that apply. [RANDOMIZE ORDER 1–7]
1. The initial cost of a the ductless mini-split heat pump is too high (i.e. too expensive)
2. I don't know enough about ductless mini-split heat pumps
3. Don't plan to stay in home long enough for it to pay off
4. Would rather trust a technology I am more familiar with
5. I'm concerned about how the ductless mini-split heat pump would look in my home
6. I don't believe my monthly energy bill would go down
7. I'm concerned about the system's performance
8. Something else, please specify [TEXT ENTRY BOX]

[TRANSITION LANGUAGE AFTER FIRST SCENARIO]: Great. We have just one more scenario for you to consider, that's slightly different than the last.

Scenario 2: Ductless ASHP – Partial Displacement

Assume you live in an 1,800 sq ft home and that **your current primary heating system is working fine**. Some people install an electric ductless mini-split heat pump to provide more cost-effective and efficient heating and cooling than their current system, to add cooling, and/or to improve their comfort, for all or some areas of their home. On average, installing a ductless mini-split heat pump to supplement your current gas heating system would cost approximately $10,000. This system would have three indoor units, typically mounted up high on a wall like in the picture below. Each indoor unit would provide heating and cooling to an open living area or room, and the system would provide a majority of your heating and cooling at lower cost than does your current system.

When used for heating, a ductless mini-split heat pump will decrease your gas bill while increasing your electric bill. Overall, you would save up to $100 a year on your energy bill. The system would provide quiet, efficient heating and cooling throughout your home while being environmentally friendly and energy efficient.

D7. How likely would you be to install a ductless mini-split heat pump in conjunction to supplement your existing system if you received no utility incentive (i.e. paid the full cost out of pocket)? As a reminder, a ductless mini-split heat pump would cost about $10,000 to supplement your current gas heating system.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D8. [ASK IF D7=1–4] How likely would you be to install a ductless mini-split heat pump in conjunction with your existing system if you received an incentive of $2,500 from your utility (i.e. reduce the total installation cost by $2,500)? This would reduce the cost of the ductless mini-split heat pump to about $7,500.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D9. [ASK IF D8=1–4] How likely would you be to install a ductless mini-split heat pump in conjunction with your existing system if you received an incentive of $5,000 from your utility (i.e. reduce the total installation cost by $5,000)? This would reduce the cost of the ductless mini-split heat pump to about $5,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D10. [ASK IF D9=1–4] How likely would you be to install a ductless mini-split heat pump in conjunction with your existing system if you received an incentive of $7,500 from your utility (i.e. reduce the total installation cost by $7,500)? This would reduce the cost of the ductless mini-split heat pump to about $2,500.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D11. [ASK IF D10=1–4] How likely would you be to install a ductless mini-split heat pump in conjunction with your existing system if you received an incentive of $10,000 from your utility? This means the system would be installed at no cost to you.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

D12. [ASK IF D11=1–3] Why would you be unlikely to install a ductless mini-split heat pump in this scenario? Please select all that apply. [RANDOMIZE ORDER 1–8]

1. I'm satisfied with my current systems and do not need to supplement my heating or cooling with a ductless mini-split heat pump
2. The initial cost of a the ductless mini-split heat pump is too high (i.e. too expensive)
3. I don't know enough about ductless mini-split heat pumps
4. Don't plan to stay in home long enough for it to pay off
5. Would rather trust a technology I am more familiar with
6. I'm concerned about how the ductless mini-split heat pump would look in my home
7. I don't believe my monthly energy bill would go down
8. I'm concerned about the system's performance
9. Something else, please specify [TEXT ENTRY BOX]

E. Willingness to Pay – Ducted Air Source Heat Pumps

[ONLY ASK SECTION E IF A7=1 AND B1=1 or 2 OR A7=1 and B2=1]

The next section will ask you how likely you would be to install an electric ducted air source heat pump in your home. Some people install a ducted air source heat pump to provide more cost-effective and efficient heating and cooling than their current system, to add or replace a central air conditioner, and/or to improve their comfort. As a reminder, this is not to sell you anything, this is for research purposes only.

Programming Note: Respondents are asked *one* Ducted ASHP Scenario depending on existing cooling.

- **IF A8=1, RANDOMIZE TO E1 OR D13**
- **IF A8=2,4, 5 or 6 RANDOMIZE TO E1 OR E7**
- **Ducted Scenario 1: Ducted ASHP – Full Replacement/Replace on Burnout**

Assume that you live in an 1,800 sq ft home and **that your current primary heating system is about to fail**. On average, installing a ducted air source heat pump to replace your current failing heating system would cost approximately $9,000—about $4,500 more than a new gas furnace. This system would reuse the existing ductwork in your home previously used by your old furnace to provide heating and cooling.

The ducted air source heat pump will decrease your gas bill while increasing your electric bill. Overall, you would save up to $150 a year on your energy bill. The system would provide quiet, efficient heating cooling throughout your home while being environmentally friendly and energy efficient.

E1. How likely would you be to install a ducted air source heat pump if you received no utility incentive (i.e. paid the full cost out of pocket)? As a reminder, a ducted air source heat pump would cost about $4,500 more than a new natural gas furnace.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)		Unlikely (2)	Very Unlikely (1)

E2. [ASK IF E1=1–4] Please indicate how likely you would be to install a ducted air source heat pump if you received an incentive of $1,150 from your utility (i.e. reduce the total installation cost by $1,150)? This would reduce the difference in cost between an air source heat pump and a new natural gas furnace to about $3,350.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E3. [ASK IF E2=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $2,250 from your utility (i.e. reduce the total installation cost by $2,250)? This would reduce the difference in cost between an air source heat pump and a new natural gas furnace to about $2,250.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E4. [ASK IF E3=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $3,375 from your utility (i.e. reduce the total installation cost by $3,375)? This would reduce the difference in cost between an air source heat pump and a new natural gas furnace to about $1,125.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E5. [ASK IF E4=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $4,500 from your utility? This would make the cost of installing a ducted air source heat pump about the same as a new natural gas furnace.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E6. [ASK IF E5=1–3] Why would you be unlikely to install a ducted air source heat pump? Please select all that apply. [RANDOMIZE ORDER 1–7]

1. The initial cost of an air source heat pump is too high (i.e. too expensive)
2. Unsure of how to apply for incentives and/or special financing for air source heat pumps
3. I don't know enough about air source heat pumps
4. Don't plan to stay in home long enough for it to pay off
5. Would rather trust a technology I am more familiar with
6. I don't believe my monthly energy bill would go down
7. I'm concerned about the system's performance
8. Something else, please specify [TEXT ENTRY BOX]

Scenario 2: Ducted ASHP – Dual Fuel Early Replacement

Assume that you live in an 1,800 sq ft home and **that your current primary heating system is older but still working.** On average, installing a ducted air source heat pump to supplement your current natural gas furnace and add the benefit of central cooling would cost approximately $8,000. This system would use the same ductwork in your home used by your furnace, and operate in place of your furnace until the temperature reached around 35 degrees Fahrenheit.

The ducted air source heat pump would decrease your gas bill while increasing your electric bill. Overall, you would save up to $100 a year on your energy bill. The system would provide quiet, efficient heating and cooling throughout your home while being more environmentally friendly and energy efficient.

E7. How likely would you be to install a ducted air source heat pump if you received no utility incentive (i.e. paid the full cost out of pocket)? As a reminder, a ducted air source heat pump would cost about $8,000 to supplement your current gas heating system and add central cooling.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E8. [ASK IF E7=1–4] Please indicate how likely you would be to install a ducted air source heat pump if you received an incentive of $2,000 from your utility (i.e. reduce the total installation cost by $2,000)? This would reduce the cost to approximately $6,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E9. [ASK IF E8=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $4,000 from your utility (i.e. reduce the total installation cost by $4,000)? This would reduce the cost to approximately $4,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E10. [ASK IF E9=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $6,000 from your utility (i.e. reduce the total installation cost by $6,000)? This would reduce the cost to approximately $2,000.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E11. [ASK IF E10=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $8,000 from your utility (i.e. the system would be installed at no cost to you)?

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E12. [ASK IF D11=1–3] Why would you be unlikely to install a ducted air source heat pump? Please select all that apply. [RANDOMIZE ORDER 1–8]

1. I'm satisfied with my current systems and do not need to supplement my heating or add cooling with an air source heat pump
2. The initial cost of an air source heat pump is too high (i.e. too expensive)
3. Unsure of how to apply for incentives and/or special financing for air source heat pumps
4. I don't know enough about air source heat pumps
5. Don't plan to stay in home long enough for it to pay off
6. Would rather trust a technology I am more familiar with
7. I don't believe my monthly energy bill would go down
8. I'm concerned about the system's performance
9. Something else, please specify [TEXT ENTRY BOX]

SCENARIO 3 – ROB Dual Fuel

Assume your existing central air conditioner is about to fail *and* your heating system is about to fail. The cost of the ducted air source heat pump, with natural gas back-up heat, is approximately $1,200 more than installing a new central air conditioner and new furnace separately.

The ducted air source heat pump with natural gas back-up heat would decrease your gas bill while increasing your electric bill. Overall, you would save up to $100 a year on your energy bill. The system would provide quiet, efficient heating and cooling throughout your home while being more environmentally friendly and energy efficient.

E13. How likely would you be to install a ducted air source heat pump if you received no utility incentive (i.e. paid the full cost out of pocket), knowing that it will provide cooling like an air conditioner while also reducing your heating bill by approximately $100 annually? As a reminder, a ducted air source heat pump with natural gas back-up heat would cost about $1,200 more than installing a new gas furnace and new central air conditioner.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E14. [ASK IF E13=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $300 from your utility (i.e. reduce the total installation cost by $300). This would reduce the difference in cost between an air source heat pump and a new natural gas furnace and new air conditioner to about $900. more than installing a new gas furnace and new central air conditioner.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E15. [ASK IF E14=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $600 from your utility (i.e. reduce the total installation cost by $600)? This would reduce the difference in cost between an air source heat pump and a new natural gas furnace and new air conditioner to about $600.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E16. [ASK IF E15=1–4] How likely would you be to install a ducted air source heat pump if you received an incentive of $900 from your utility (i.e. reduce the total installation cost by $900)? This would reduce the difference in cost between an air source heat pump and a new natural gas furnace and new air conditioner to about $300.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E17. [ASK IF E16=1–4] How likely would you be to install a ducted air source heat pump with natural gas back-up heat if you received an incentive of $1,200 from your utility (This would make the cost of installing a ducted air source heat pump about the same as a new natural gas furnace and new air conditioner).

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

E18. [ASK IF E17=1–3] Why would you be unlikely to install a ducted air source heat pump? Please select all that apply. [RANDOMIZE ORDER 1–7]

1. The initial cost of an air source heat pump is too high (i.e. too expensive)
2. Unsure of how to apply for incentives and/or special financing for air source heat pumps
3. I don't know enough about air source heat pumps
4. Don't plan to stay in home long enough for it to pay off
5. Would rather trust a technology I am more familiar with
6. I don't believe my monthly energy bill would go down
7. I'm concerned about the system's performance
8. Something else, please specify [TEXT ENTRY BOX]

F. *Willingness to Pay – Other Low-Carbon Technology*

The next section will ask you how likely you would be to install other low-carbon technologies.

F1. What kind of water heater do you currently have?

1. Gas water heater
2. Electric water heater
3. Other, please specify [TEXT ENTRY BOX]

F2. [ASK IF F1=1] An electric, heat pump water heater provides several benefits compared to a gas water heater, including improved energy efficiency and lower water heating costs. Consider a scenario in which you need to replace your gas water heater within the next two years. How likely would you be to replace your gas water heater with an electric heat pump water heater? Heat pump water heaters cost approximately $1,000 more than new gas water heater on average, and could save $80–$120 annual on your energy bill.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

F3. What type of cooktop do you currently have?
1. Gas cooktop
2. Electric cooktop
3. Other

F4. [ASK IF F3=1] An electric, induction cooktop provides several benefits compared to gas cooktop, including a more even and precise heating surface, lower energy usage, and improved indoor air quality and safety. Consider a scenario in which you are considering updating your stove or cooktop within the next two years. How likely you would be to install an induction cooktop? Assume your energy costs remain approximately the same and the cost to purchase an induction cooktop is $300 more than a new gas cooktop, on average.

Very likely (6)	Likely (5)	Somewhat likely (4)	Somewhat unlikely (3)	Unlikely (2)	Very Unlikely (1)

G. Climate Change

G1. Please rate how much you agree or disagree with the following statements: [1=STRONGLY DISAGREE, 2=SOMEWHAT DISAGREE, 3=SOMEWHAT AGREE, 4=STRONGLY AGREE, 98=DON'T KNOW] [RANDOMIZE ORDER]
1. I am very concerned about climate change
2. Climate change is a threat to our environment
3. I'm worried about how climate change will impact my family/community
4. I try to consider the environmental impact for all the decisions I make
5. I consider climate change when making decisions related to heating/cooling my home

H. Demographics

To close, we have a few questions about your household. These will be kept strictly confidential and will only be used in aggregate with other responses.

H1. Which of the following categories best represents your approximate annual household income from all sources in 2021 before taxes?
1. < $30,000
2. Between $30,000 and $49,999
3. Between $40,000 and $49,999
4. Between $50,000 and $59,999
5. Between $60,000 and $79,999
6. Between $80,000 and $99,999
7. Between $100,000 and $119,999
8. $120,000 or more
98. Don't know
99. Prefer not to answer

H2. What is the highest level of education you've completed so far?

1. Some high school, no diploma
2. High school diploma or GED
3. Associates degree
4. Some college, no degree
5. Bachelor's degree
6. Graduate or professional degree
99. Prefer not to answer

H3. What year was your home built?

1. 2010 or later
2. 2000 to 2009
3. 1990 to 1999
4. 1980 to 1989
5. 1970 to 1979
6. 1960 to 1969
7. 1950 to 1959
8. 1940 to 1949
9. Earlier than 1940
98. Don't know
99. Prefer not to answer

H4. Approximately how may years old is your heating system? Please estimate the age of your system in the drop-down menu. [DROP DOWN NUMERIC 1–20]

H5. How many years have you lived in your current home?

1. Less than 1 year
2. 1 year to less than 5 years
3. 5 years to less than 10 years
4. 10 years or more
99. Prefer not to answer

H6. How many people, including yourself, live in your home full time?

1. 1
2. 2
3. 3
4. 4
5. 5
6. 6
7. 7 or more people
98. Don't know
99. Prefer not to answer

H7. Is English your first language?
1. Yes
2. No, please specify what your first language is [TEXT ENTRY BOX]

H8. What is your race? Please select all that apply. [RANDOMIZE ORDER]
1. White
2. Black or African American
3. American Indian or Alaska Native
4. Asian
5. Native Hawaiian or Other Pacific Islander
6. Other: [TEXT ENTRY BOX]

H9. What is your ethnicity?
1. Hispanic or Latino or Spanish Origin
2. Not Hispanic or Latino or Spanish Origin
3. Other: [TEXT ENTRY BOX]

Gift Card

Those are all of our questions! Please verify your contact information to be entered into the drawing to win one of five $100 Amazon.com gift cards. Your information will only be used to email you a gift card; PSE will not use it for marketing purposes, and they will not update any of your billing or emailing preferences with this information. Please note that if you do not complete your email address, or only fill in some of the fields below, you will not be entered to win a gift card.

Name: [TEXT ENTRY BOX]

Best Email: [TEXT ENTRY BOX]

End of Survey Message

Thank you for your responses and your time!

PSE offers a variety of energy efficiency programs that could help you save energy and manage your monthly bills. For more information on other ways to save, please visit https://www.pse.com/rebates.

Appendix C. Heat Pump Cost and Market Barriers Interview Guide (HVAC Contractors)

Interview Overview: The purpose of these interviews is to collect data from HVAC contractors and builders active in Puget Sound Energy's service territory to determine the costs to install different configurations of air source heat pumps across a variety of different gas-heated homes. Additionally, these interviews seek to collect information about use of cold climate heat pumps and additional barriers to electrifying heating systems from PSE gas customers.

Research Objectives	Corresponding Question Numbers
Understand contractor perspective on heat pump sales by system type, attitudes towards cold climate heat pumps, and barriers to electrification	A1–A8
Assess costs for primary baseline heating and cooling equipment configurations	B1–B5
Assess costs per ton and by scenario for various heat pump configurations	C1–C13

Target Audience: Residential service providers (HVAC contractors) that have ideally installed at least 50 air source heat pumps in and around PSE's service territory in 2021

Target: Up to 15 contractors

Estimated time: 30 to 45 minutes

A. Company and Heat Pump Market Overview

A1. What geographic areas does your company serve?

A2. In the past 12 months, about how many HVAC systems has your business installed in existing single-family homes in PSE's service territory, which includes King, Kittitas, Thurston, Pierce, and Snohomish Counties? [Follow-on: Please note that all questions we are asking about sales and costs are focused on PSE's service territory, though we realize it may be difficult to consider just these areas. Where possible, please consider PSE's territory or jobs within a 50-mile radius of Seattle]

A3. In the past 12 months, about how many **ductless mini-split heat pumps** has your business installed in **existing single-family homes**?

1. Thinking about the homes in which your company installed ductless mini-split heat pumps, approximately what percentage of these ductless mini-split heat pumps were installed in homes heated with gas, what percentage were installed in homes heated with electric resistance, and what percentage were installed in homes heated with other fuels?
2. Approximately what percentage of these systems were installed as **sole sources of heating to the home**, what percentage were installed as **primary or supplemental sources of heating**, what percentage were installed as **zonal sources of heating, and what percentage were installed primarily for providing cooling**?
   (1) [Definition: For this question, we are considering installations to be primary or supplemental sources of heating as systems that are installed with the intent of being operated in conjunction with an existing heating system that is used as a backup source of heating. We are considering installations to be zonal source of heating if they are installed as the sole source of heating in a previously unheated space like a new addition or bonus room where the home is otherwise served by a separate system]
   (2) [Probe: If percentages do not add up to 100%, ask about alternative applications]
3. What are the primary reasons why customers are interested in installing ductless mini-split heat pumps? [Probe: Replacing old system, saving energy, adding cooling, reducing greenhouse gas emissions]

A4. How has the number of **ductless mini-split heat pumps** you've installed changed in the past 12 months relative to the previous 12 months? [Probe: increased, decreased, stayed the same]

1. How did the COVID-19 pandemic impact your installations of **ductless mini-split heat pumps**?

A5. In the past 12 months, about how many centrally ducted or unitary air source heat pumps has your business installed in existing single-family homes?

1. Approximately what percentage of these ducted air source heat pumps were installed in homes heated with gas, what percentage were installed in homes heated with electric resistance, and what percentage were installed in homes heated with other fuels?
2. Thinking about the homes in which your company installed centrally ducted air source heat pumps, approximately what percentage of these systems were installed as **sole sources of heating** vs. installed in **dual-fuel configuration** with an existing or new natural gas furnace? [Probe: If percentages do not add up to 100%, ask about alternative applications]
3. What are the primary reasons why customers are interested in installing centrally ducted air source heat pumps? [Probe: Replacing old furnace, replacing old air conditioner, saving energy, adding cooling, reducing greenhouse gas emissions] Do these reasons differ between standalone centrally ducted ASHPs and dual-fuel systems?

4. When you install centrally ducted heat pumps in dual-fuel configurations, how do you typically determine switchover temperatures between the furnace and heat pump? What factors influence what balance point you use?
5. When you install centrally ducted heat pumps in dual-fuel configurations, do you typically replace the furnace as well? What factors determine whether you replace the furnace when installing the heat pump?

A6. How has the number of **centrally ducted air source heat pumps** you've installed changed in the past 12 months relative to the previous 12 months? [Probe: increased, decreased, stayed the same]
1. Does this differ between standalone centrally ducted ASHPs and dual-fuel systems?
2. How did the COVID-19 pandemic impact your installations of **centrally ducted air source heat pumps?**

A7. How familiar are you with **cold climate air source heat pumps?** [Prompt: The Northeast Energy Efficiency Partnerships certifies air source heat pumps as "cold climate" if they include a variable-speed compressor, have an HSPF of 9 or higher, and are able to maintain a COP of at least 1.75 at 5°F]
1. How frequently do you install cold climate heat pumps? What factors determine whether you install a cold climate heat pump in a customer's home vs. a non-cold climate heat pump?
2. [If does not install] Why not?

A8. What are the primary challenges **you** face when converting a home from using gas for heating to using heat pumps for heating?
1. What are the primary challenges a **customer** will face if they are interested in converting a home from using gas for heating to using a heat pump for heating?
2. How frequently are electrical improvements needed when you install heat pumps? [Prompt: For example, panel upgrade or additional wiring]

A9. Do customers typically request air source heat pumps or do you propose them as solutions to meet their needs? Does this differ between ductless mini-splits, centrally ducted ASHPs, and dual-fuel centrally ducted ASHPs?

B. Baseline System Costs

The next few questions ask about the costs associated with retrofitting existing gas heating systems with similar equipment. I understand that costs vary significantly on a project-by-project basis, but please provide your best estimate of a typical installation matching the description provided. This information will be used to help PSE understand how best to set incentive levels for future energy programs.

B1. What is the approximate cost for replacing a **gas furnace?** Assume the furnace is a minimum efficiency system with no additional features like multiple stages or modulating capacity.

B2. What is the approximate cost for replacing a **gas boiler?** Again, assume the boiler is a minimum efficiency system with no additional features.

B3. What is the approximate cost for replacing a **gas wall furnace?**

B4. What is the approximate cost for replacing a **central air conditioner?** Assume the home is approximately 1,800 square feet with two floors.

1. Approximately how large of an air conditioner (in nameplate cooling capacity) would this system be?

B5. What is the approximate cost for installing a central air conditioner in a home with a gas furnace that did not previously have central air conditioning?

1. In the past three years, what change, if any, have you noticed in customer interest in installing central AC for the first time? [Probe: increased, decreased, stayed the same] Why do you think this is?

C. Heat Pump Costs

The next several questions ask about the costs associated with installing heat pumps to retrofit existing gas-heated homes. I will ask you for your estimate of costs for installing a variety of different heat pump systems and sizes, as well as an estimate for more specific scenarios. I understand that costs vary significantly on a project-by-project basis, but please provide your best estimate of a typical installation matching the description provided. Later on, I will ask about typical factors that can impact the cost of installing heat pumps in gas-heated homes.

C1. What is the approximate cost per ton of nameplate cooling capacity to install a **ductless mini-split heat pump** in an existing gas-heated home to fully replace the existing system? Assume this is a standard efficiency, code compliant system.

1. Approximately how much more per ton would it cost to install an ENERGY STAR certified system?
2. Approximately how much more per ton would it cost to install a **cold climate ductless mini-split heat pump**? [Confirm INCREMENTAL cost]

C2. What is the approximate cost per ton of nameplate cooling capacity to install a **centrally ducted air source heat pump** to fully replace an existing gas furnace? Assume that this is a standard efficiency, code compliant single-stage system.

1. Approximately how much more per ton would it cost to install a dual-stage system? What about ENERGY STAR certified?
2. Approximately how much more per ton would it cost to install a **cold climate centrally ducted air source heat pump?** [Confirm INCREMENTAL cost]

C3. What is the approximate cost per ton of nameplate cooling capacity to install a **centrally ducted air source heat pump** in a **dual-fuel configuration** with an **existing** gas furnace? Assume the systems are compatible and both systems are standard efficiency, code compliant systems.

C4. Approximately how much would it cost to install a **centrally ducted air source heat pump** in a **dual-fuel configuration** with a **new** gas furnace? Assume the systems are compatible and both systems are standard efficiency, code compliant systems.

C5. What are the primary factors that could drive up the cost of **ductless mini-split heat pump** installations beyond the estimate you provided previously? [Probe for potential cost adders for factors and costs specific to gas conversions, especially electrical upgrades]

1. Do you install third-party or manufacturer proprietary controls with ductless mini-split heat pumps? Why or why not?
2. [If yes] How frequently do your installations include added controls? How much do those controls typically add to the cost of an installation?

C6. What are the primary factors that could drive up the cost of **centrally ducted heat pump** installations beyond the estimate you provided previously? [Probe for potential cost adders for factors and costs specific to gas conversions, especially electrical upgrades]

1. Do you install third-party or manufacturer proprietary controls with centrally ducted heat pumps? Why or why not?
2. [If yes] How frequently do your installations include added controls? How much do those controls typically add to the cost of an installation?

I am going to now provide you with more specific examples of residential homes and then ask you about your best estimate for the costs associated with a project of similar size and scope.

Scenario 1: Gas Furnace Full Replacement

[Building Size] The customer owns a 2-story, 1,800 sq. ft. single family detached [style] home that is approximately 40 years old.

[Current System] The current system is a standard efficiency gas furnace approximately 15 years in age. The customer does not have central air conditioning but is interested in adding cooling.

[New System] The customer wants to replace their furnace with a centrally ducted air source heat pump that will provide heating and cooling to the entire home.

C7. Have you worked on any projects similar in size or scope to this project?

1. Yes
2. No

C8. [IF C7=1] Based on your experience with similar projects, what system would you quote for this home and what would be the typical costs for this installation?

C9. [IF C7=2] Give your best estimate of what system you would quote for this home and at what cost if you were asked to provide a quote for this project by a potential client.

C10. Is this heat pump retrofit scenario that is a common recommendation you would make for a home like this?

1. **[If does not recommend]** What would you recommend instead?

Scenario 2: Gas Furnace Dual Fuel Installation

[Building Size] The customer owns a 2-story, 1,800 sq. ft. single family detached [style] home that is approximately 40 years old.

[Current System] The current system is a relatively new standard efficiency gas furnace approximately 5 years in age. The customer does not have central air conditioning but is interested in adding cooling.

[New System] The customer wants to install a centrally ducted air source heat pump to provide cooling and to save money on heating costs while keeping the existing furnace in place, operating in a dual fuel capacity.

C11. Have you worked on any projects similar in size or scope to this project?

1. Yes
2. No

C12. [IF C11=1] based on your experience with similar projects, what system would you quote for this home and what would be the typical costs for this installation?

C13. [IF C11=2] give your best estimate of what system you would quote for this home and at what cost if you were asked to provide a quote for this project by a potential client.

C14. Is this heat pump retrofit scenario that is a common recommendation you would make for a home like this?

1. [If does not recommend] what would you recommend instead?

Scenario 3: Gas Boiler Full Replacement

[Building Size] The customer owns a 2-story, 1,800 sq. ft. single family detached [style] home that is approximately 40 years old.

[Current System] The current system is a standard efficiency gas boiler approximately 15 years in age. The customer does not have central air conditioning but is interested in adding cooling.

[New System] The customer wants to install a ductless mini-split heat pump with one outdoor unit and four indoor units to serve as the sole source of heating and cooling to the entire home. The indoor units will be installed in the kitchen and living room on the first floor and in two bedrooms on the second floor. They will keep the existing boiler in place but do not expect to use it outside of emergencies.

C15. Have you worked on any projects similar in size or scope to this project?

1. Yes
2. No

C16. [IF C15=1] Based on your experience with similar projects, what system would you quote for this home and what would be the typical costs for this installation?

C17. [IF C15=2] Give your best estimate of what system you would quote for this home and at what cost if you were asked to provide a quote for this project by a potential client.

C18. Is this heat pump retrofit scenario that is a common recommendation you would make for a home like this?
   1. [If does not recommend] What would you recommend instead?

Scenario 4: Gas Boiler Partial Displacement

[Building Size] The customer owns a 2-story, 1,800 sq. ft. single family detached [style] home that is approximately 40 years old.

[Current System] The current system is a relatively new standard efficiency gas boiler approximately 5 years in age. The customer does not have central air conditioning but is interested in adding cooling.

[New System] The customer wants to install a ductless mini-split heat pump with one outdoor unit and three indoor units to provide heating and cooling to most of the home. The indoor units will be installed in the kitchen and living room on the first floor and in the primary bedroom on the second floor. They expect to keep using the existing boiler to provide heat to remaining areas and during colder periods.

C19. Have you worked on any projects similar in size or scope to this project?
   1. Yes
   2. No

C20. [IF C19=1] Based on your experience with similar projects, what system would you quote for this home and what would be the typical costs for this installation?

C21. [IF C19=2] Give your best estimate of what system you would quote for this home and at what cost if you were asked to provide a quote for this project by a potential client.

C22. Is this heat pump retrofit scenario that is a common recommendation you would make for a home like this?
   1. [If does not recommend] What would you recommend instead?

Closing

Those are all of my questions for today! Is there anything else you'd like to mention?

If I have any follow up questions, can I reach back out to you?

Thank you very much for your time. As a thank you, we would like to offer you a $150 Amazon.com gift card. Please provide us with your name and email address so we can send you your electronic gift card.

Appendix D. Heat Pump Cost and Market Barriers Interview Guide (Builders)

Interview Overview: The purpose of these interviews is to collect data from builders active in Puget Sound Energy's service territory to determine the costs to install different configurations of air source heat pumps in new construction. Additionally, these interviews seek to collect information about use of cold climate heat pumps and additional barriers to electrifying heating systems from PSE gas customers.

Research Objectives	Corresponding Question Numbers
Understand builder perspective on heat pumps in all-electric and dual-fuel homes, market trends, and customer interest	A1–A8
Assess costs for primary baseline and all-electric heating and cooling equipment configurations in new construction	B1–B8

Target Audience: Builders that have developed new homes using heat pumps for space heating, cooling, and/or hot water around PSE's service territory

Target: Up to 5 builders

Estimated time: 30 minutes

D. Company and All-Electric Home Market Overview

D1. In the past 12 months, about how many new homes has your company built in PSE's service territory, which includes King, Kittitas, Thurston, Pierce, and Snohomish Counties? [Follow-on: Please note that all questions we are asking about sales and costs are focused on PSE's service territory, though we realize it may be difficult to consider just these areas. Where possible, please consider PSE's territory or jobs within a 50-mile radius of Seattle]

1. Approximately how many were single-family vs. multifamily?
2. Do you typically build custom homes or build to spec?

D2. Thinking about the single-family homes you have constructed in the past 12 months, what proportion have been all-electric with no gas connection?

1. What are the primary reasons for why you make the decision to build all-electric? [Probe: Is there customer interest in all-electric? Does the cost of the gas connection come into play?]
2. How has the proportion of all-electric homes you've constructed changed in the past three years? [Probe: increased, decreased, stayed the same]

D3. Of the all-electric homes you've constructed in the past 12 months, approximately what percentage use **ductless mini-split heat pumps** for heating and cooling? Why is that? [Probe: why they are for/against installation of ductless mini-split heat pumps]

1. How often do you install ductless mini-split heat pumps in **dual-fuel** homes (that is homes with gas and electric connections)? Why is that? [Probe: what are they used for? Are they typically used for primary heating, supplementary heating, or just cooling?]

D4. Of the all-electric homes you've constructed in the past 12 months, approximately what percentage use **centrally ducted or unitary air source heat pumps** for heating and cooling? Why is that? [Probe: why they are for/against installation of centrally ducted or unitary air source heat pumps]

1. How often do you install centrally ducted air source heat pumps in **dual-fuel** homes? Why is that? [Probe: what are they used for? Are they typically used for primary heating, supplementary heating, or just cooling?]

D5. Of the all-electric homes you've constructed in the past 12 months, approximately what percentage use **electric resistance baseboards or furnaces** for heating? Why is that?

1. How often do these homes also have cooling? Why is that?
2. [If yes] What type of cooling system is most common in these instances?

D6. What circumstances make you most likely to choose a heat pump for a new home?

1. Does this differ whether the home is all-electric or dual-fuel?
2. What makes you more likely to choose a ductless or centrally ducted air source heat pump for a new home?

D7. What are the primary reasons why you choose to use heat pump vs. gas heating systems for new homes?

1. For new homes with gas connections where you also install a heat pump but no gas furnace, what is the primary reason for using a heat pump in place of a gas heating system?

D8. Of the all-electric homes you've constructed in the past 12 months, approximately what percentage use **heat pump water heaters** for domestic hot water? Why is that?

1. How often do you install heat pump water heaters in **dual-fuel** homes? Why is that?

D9. Of the all-electric homes you've constructed in the past 12 months, approximately what percentage use **induction stoves**? Why is that?

1. How often do you install induction stoves in **dual-fuel** homes? Why is that?

D10. Are you familiar with cold climate air source heat pumps? [Prompt: The Northeast Energy Efficiency Partnerships certifies air source heat pumps as "cold climate" if they include a variable-speed compressor, have an HSPF of 9 or higher, and are able to maintain a COP of at least 1.75 at 5°F]

1. How frequently do you install cold climate heat pumps in your new homes? What factors determine whether you install a cold climate heat pump in a new home vs. a non-cold climate heat pump?
2. [If does not install] Why not?

D11. In the past three years, how has homebuyer interest in all-electric vs. dual-fuel homes changed? [Probe: Increased, decreased, stayed the same] Why do you think that is?

1. For homebuyers who are skeptical of all-electric homes, what are their primary concerns about buying an all-electric home?
2. Has the 2018 Washington State Energy Code impacted whether you choose to use electric heating and cooling or build all-electric homes?
3. [If original response to A11 is increased or decreased] Are there other key drivers for why your organization has been building [more/fewer] all-electric homes in the past three years? What impacts your decision-making process on whether to build all-electric or dual-fuel?

D12. Regardless of whether you are installing a heat pump or a gas system in a new home, do you typically install code-minimum equipment or do you install more efficient equipment, such as ENERGY STAR-certified appliances? Why is that? [Probe: Is code compliance a key driver for your decision to install higher efficiency equipment?]

E. Baseline and All-Electric Home Costs

The next few questions ask about new dual-fuel single-family homes and the costs for the HVAC systems. We understand that new homes can often vary in size, layout, and customer interests but we ask that you consider a typical single-family home with both gas and electric utility connections.

E1. Characterize a typical single-family home you have built in the past 12 months with both gas and electric utility connections. Be specific. [Probe: Square footage, size/layout, cost per square foot]

E2. Describe the HVAC system that you would include in a typical dual-fuel home. [Probe: Give an example, e.g. Gas furnace with central AC, on-demand gas water heater]

1. Do you typically install ENERGY STAR or other high efficiency equipment? Why is that?
2. Can you give examples of typical costs for each of the components you mentioned?
   (1) Heating system
   (2) Cooling system [if heating system is not heat pump]
   (3) Water heating system

E3. Approximately how much does it typically cost to provide a gas connection to the new home?

The next several questions ask about new **all-electric** single-family homes and the costs for all-electric HVAC systems.

E4. How would a typical all-electric single-family home be similar/different to what you described previously as a typical dual-fuel home? [Prompt with what respondent had previously provided] [Probe for specific elements: size of home, heating/cooling equipment, location]

E5. Describe the HVAC system that you would include in a typical all-electric home. [Probe: Give an example, e.g. ductless mini-split heat pumps, heat pump water heater]

1. Do you typically install ENERGY STAR or other high efficiency equipment? Why is that?
2. Can you give examples of typical costs for each of the components you mentioned?
   (1) Heating system
   (2) Cooling system [if heating system is not heat pump]
   (3) Water heating system

E6. [If B5 is a ductless mini-split heat pump] If you were to build a home with a centrally ducted air source heat pump instead of a ductless mini-split heat pump, approximately how much more or less would it cost? [Confirm INCREMENTAL cost]

E7. [If B5 is a centrally ducted mini-split heat pump] If you were to build a home with a ductless mini-split heat pump instead of a centrally ducted air source heat pump, approximately how much more or less would it cost? [Confirm INCREMENTAL cost]

E8. If you were to instead install a heat pump water heater for domestic hot water instead of a storage water heater, how much would it cost? [Confirm INCREMENTAL cost]

E9. With all other aspects of the home being equal, do you consider all-electric homes more or less expensive to build than dual-fuel homes? Why is that? [Probe for specific cost elements]

Closing

Those are all of my questions for today! Is there anything else you'd like to mention?

If I have any follow up questions, can I reach back out to you?

Thank you very much for your time. As a thank you, we would like to offer you a $150 Amazon.com gift card. Please provide us with your name and email address so we can send you your electronic gift card.

DEMAND FORECAST ANALYSIS

APPENDIX D

2023 Gas Utility Integrated Resource Plan

PUGET SOUND ENERGY

Contents

1. Demand Forecast Methodology

Puget Sound Energy (PSE) employed time-series econometric methods to forecast monthly energy demand and peaks for PSE's gas utility service area. We gathered sales, customer, demand, weather, economic, and demographic variables to model use per customer (UPC), customer counts and peaks. Once we completed the modeling, we used internal and external forecasts of new major demand (block loads), retail rates, economic and demographic drivers, normal weather with climate change assumptions, and demand side resources (DSR) to create a 27-year projection of monthly demand and peaks. For Puget Sound Energy's 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP), block loads refer to large demand entities entering the system, leaving the system, or dramatically changing their demand in a way we would not otherwise capture in the modeling. The IRP's base demand forecast for energy and peaks reflects DSR, including committed short-term conservation program targets and short-term codes and standards. Figure D.1 depicts the demand forecast development process.

Figure D.1: Demand Forecast Development Process

Estimate Models: Use per Customer, Customer Counts, Peak

- Billed sales volume and system loads
- Customer counts
- Economic and demographic observations
- Effective retail rates
- Weather observations at Sea-Tac Airport station

Forecast Models: Use per Customer, Customer Counts, Peak

- Economic and demographic forecasts
- Normal weather using historic and forecasts temperatures
- Retail rate forecast

Base Demand Forecasts, before additional DSR: Demand and Peak

- 2022-2023 effects of DSR, including programmatic conservation and code and standards
- Billing cycles schedules
- Losses
- Major projects including system additions and departures, CNG forecast

Final Demand Forecast, after additional DSR: Demand and Peak

- 2023 Gas Utility IRP Demand Side Resources 2024–2050
- Effects of 70% more efficient building codes
- Effects of the Climate Commitment Act
- Impacts of electrification

2. Model Estimation

To capture incremental customer growth, temperature sensitivities, and economic sensitivities, we forecasted billed sales by estimating UPC and customer count models. We created models for the following major classes to best estimate each class's specific driving forces.

- Firm classes — residential, commercial, industrial, commercial large volume, and industrial large volume
- Interruptible classes — commercial and industrial
- Transport classes — commercial firm, commercial interruptible, industrial firm, and industrial interruptible

Each class's historical sample period ranged from as early as January 2003 to March 2021.

➔ See Chapter Five: Demand Forecasts for how we developed the economic and demographic input variables.

2.1. Customer Counts

We estimated monthly customer counts by class. These models use explanatory variables such as population, total employment, and manufacturing employment. We estimated some customer classes via first differences, with economic and demographic variables implemented in a lagged or polynomial distributed form to allow delayed variable impacts. We did not estimate some smaller customer classes, but instead held them constant. We also imposed autoregressive moving average (ARMA) (p,q) error structures subject to model fit.

The equation we used to estimate customer counts is:

$$\mathrm{CC}_{\mathrm{C,t}} = \boldsymbol{\beta}_{\mathbf{C}}[\propto_{\mathrm{C}} \quad \mathbf{D}_{\mathrm{M,t}} \quad \mathrm{T}_{\mathrm{C,t}} \quad \mathbf{ED}_{\mathrm{C,t}}] + \mathrm{u}_{\mathrm{C,t}},$$

The details for the estimating equation components are as follows:

$CC_{C,t}$	=	Count of customers in Class C and month t
C	=	Service and class, as determined by tariff rate
t	=	Estimation period
$\boldsymbol{\beta_C}$	=	Vector of CC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
$\propto_C$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{D}_{M,t}$	=	Vector of month/date-specific indicator variables
$T_{C,t}$	=	Trend variable (not included in most classes)
$\boldsymbol{ED}_{C,t}$	=	Vector of economic and/or demographic variables
$u_{C,t}$	=	ARMA error term (ARMA terms chosen in model selection process)

Note: The term vector or boldface type denotes one or more variables in the matrix.

2.2. Use per Customer

We estimated monthly UPC at the class level using explanatory variables, including heating degree days (HDD), seasonal effects, retail rates, average billing cycle length, and various economic and demographic variables such as income and employment levels. We modeled some variables, such as retail rates and economic variables, in a lagged form to account for short-term and long-term effects on energy consumption. Finally, depending on the equation, we employed an ARMA(p,q) error structure to address issues of autocorrelation.

The equation we used to estimate use per customer is:

$$\frac{UPC_{C,t}}{D_{c,t}} = \boldsymbol{\beta_C}\left[\propto_C \quad \frac{\boldsymbol{DD}_{C,t}}{D_{C,t}} \quad \boldsymbol{D}_{M,t} \quad \boldsymbol{RR}_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t}$$

$UPC_{C,t}$	=	Billed Sales ($Billed\ Sales_{C,t}$) divided by Customer Count ($CC_{C,t}$), in class C, month t
$D_{C,t}$	=	Average number of billed cycle days for billing month t in class C
$\boldsymbol{\beta_C}$	=	Vector of UPC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
$\propto_C$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{DD}_{C,t}$	=	Vector of weather variables, a calculated value that drives monthly heating and/or cooling demand.

$$\boldsymbol{HDD}_{C,Base,t} = \sum_{d=1}^{Cycle_t} |max(0, Base\ Temp - Daily\ Avg\ Temp_d)| * BillingCycleWeight_{C,d,t}$$

$\boldsymbol{D}_{M,t}$	=	Vector of month/date-specific indicator variables
$\boldsymbol{RR}_{C,t}$	=	The effective retail rate. The rate is smoothed, deflated by a Consumer Price Index, and interacts with macroeconomic variables, and/or is further transformed.
$\boldsymbol{ED}_{C,t}$	=	Vector of economic and/or demographic variables
$u_{C,t}$	=	ARMA error term

The term vector or boldface type denotes one or more variables in the matrix.

2.3. Gas Utility Peak Day

The gas peak demand model relates observed monthly peak system demand to monthly weather-normalized delivered demand. The model also controls for other factors, such as observed temperature, exceptional weather events, and the day of the week.

The primary driver of a peak demand event is temperature. In winter, colder temperatures yield higher demand during peak hours, especially on evenings and weekdays. The peak demand model uses the difference of observed peak temperatures from normal monthly peak temperature and month-specific variables, scaled by normalized average monthly delivered demand, to model the weather and non-weather sensitive components of monthly peak demand. In the long-term forecast, growth in monthly weather-normalized delivered demand will drive growth in forecasted peak demand, given the relationships established by the estimated regression coefficients.

The equation we used to estimate the gas utility peak day is:

$$\max(Day_{1,t} \ldots Day_{Days_{t,},t}) = \boldsymbol{\beta}\left[BDemand_{N,t} \quad \Delta Temperature_{N,t} HDemand_{N,t} \quad \boldsymbol{D}_{M,t} \quad \boldsymbol{D}_{WE,t} \quad \boldsymbol{S}_{i,t}\right] + \varepsilon_t$$

$Day_{i,t}$	=	Firm delivered dekatherms for day i
$Days_{t},$	=	Total number of days in a month at time t
$\boldsymbol{\beta}$	=	Vector of gas peak day regression coefficients
$HDemand_{N,t}$	=	Normalized monthly firm-delivered heating demand
$BDemand_{N,t}$	=	Normalized monthly firm-delivered base load demand
$\Delta\, Temperature_{N,t}$	=	Deviation of observed daily average temperature from the normal minimum temperature for that month
$\boldsymbol{D}_{M,t}$	=	Vector of monthly date indicator variables
$\boldsymbol{D}_{WE,t}$	=	Vector of date-specific indicator variables
$\mathbf{S}_{i,t}$	=	Vector of snow day binaries
ε_t	=	Error term

The gas utility peak day equation uses monthly normalized firm-delivered demand as an explanatory variable; the estimated model weighs this variable heavily. Therefore, the peak day equation will follow a similar trend as the monthly firm demand forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is that it uses the demand of distinct gas customer classes to help estimate gas peak demand.

2.4. Billed Sales Forecast

We used the described UPC and customer count models and external and internally derived forecast drivers to forecast billed sales. We fitted economic, demographic, and retail rate forecasts, and normal monthly degree days, including climate change with model estimates to create the 27-year UPC and customer count projections by class. We formed the total billed sales forecasts by class by multiplying forecasted UPC and customers ($\widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t}$), then adjusting for known future discrete additions and subtractions ($Block\ Sales_{C,t}$).

We incorporated major block loads changes as additions or departures to the sales forecast as they are not reflected in historical trends in the estimation sample period. Examples of such items include large greenfield developments, changes in usage patterns by large customers, schedule switching by large customers, and fuel switching by customers. Finally, for the 2023 Gas Utility IRP base demand forecast, we reduced the forecast of billed sales by DSR. DSR ($DSR_{C,t}$) includes new conservation programs by class, using established conservation targets in 2022–2023 and short-term effects of codes and standards for 2022–2023.

The total billed sales forecast equation by class and service is:

$$Billed\ Sales_{C,t} = \widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t} + Block\ Sales_{C,t} - DSR_{C,t}$$

t	=	Forecast time horizon
$\widehat{UPC}_{C,t}$	=	Forecast use per customer
$D_{C,t}$	=	Average number of scheduled billed cycle days for billing month t in class C
$\widehat{CC}_{C,t}$	=	Forecast count of customers
$DSR_{C,t}$	=	Base Forecast: programmatic conservation targets and codes and standards for 2022 and 2023
$Block\ Sales_{C,t}$	=	Expected entering or exiting sales not captured as part of the customer count or UPC forecast.

We calculated total billed sales each month as the sum of the billed sales across all customer classes.

$$\text{Total } Billed\ Sales_t = \sum_{c} Billed\ Sales_{C,t}$$

2.5. Base and Final Demand Net of DSR Forecasts

To calculate the final demand, we applied the DSR from this IRP to the base demand forecast. We used this process for the energy demand and peak demand.

2.5.1. Energy Demand

We formed total system demand by distributing monthly billed sales into calendar sales, then made minor adjustments for company own use and losses from distribution. The gas demand forecast ($\widehat{Demand}_{N,t}$) forms the 2023 Gas Utility IRP gas utility base demand forecast. We calculated final demand using the optimal DSR bundles found in this IRP.

2.5.2. Peak Demand

We used the peak models, the assumption of normal design temperature, forecasted total system normal demand less DSR ($\widehat{Demand}_t - DSR_t$), and short-term forecasted peak DSR targets to forecast peak demand. Peak DSR and demand DSR are related but distinct: different conservation measures may have more significant or minor impacts on peak when compared with energy. Thus, the peak model reflects exact peak DSR assumptions from program activities and codes and standards, as opposed to simple downstream calculations from demand reduction. These calculations yield system daily peak demand for each winter month based on normal design temperatures.

$$Peak\ Demand_t = F(\widehat{Demand}_{t,}, \Delta Temperature_{N,Design,t}) - DSR_{Peak,t}$$

$Peak\ Demand_t$	=	Forecasted maximum system demand for month t
t	=	Forecast time horizon
$\widehat{Demand}_t$	=	Forecast of delivered demand for month t
$\Delta Temperature_{Normal,Design,t}$	=	Deviation of peak hour/day design temperature from monthly normal peak temperature
$DSR_{Peak,t}$	=	Peak DSR resulting from programmatic conservation targets and codes and standards from the previous conservation potential assessment (CPA)

For the gas peak day forecast, the design peak day is a 52-heating-degree day (13 degrees Fahrenheit average temperature for the day). We evaluated this standard when we adopted climate change models for future weather.

➔ See the Climate Change Forecasts section of this Appendix for the analysis.

We netted the effects of the 2022 and 2023 DSR targets from the peak demand forecast to account for programmatic conservation already underway for the 2023 Gas Utility IRP base peak demand forecast. Additionally, we netted the effects of codes and standards in 2022 and 2023 and created the base peak demand forecast. Once we determined the optimal DSR for this IRP, we adjusted the peak demand forecast for the peak contribution of future DSR, creating the final demand peak forecast.

2.6. Details of the Natural Gas Forecasts

The natural gas forecast is comprised of demand from several different classes. The firm classes are residential, commercial, industrial, commercial large volume, and industrial large volume. The interruptible classes are commercial and industrial. Transport classes are commercial firm, commercial interruptible, industrial firm, and industrial interruptible. We show details of each class in the following section as well as describe the details of the base and zero-customer growth demand forecasts developed for PSE's gas sales service.

2.6.1. Natural Gas Customer Counts – Base Demand Forecast

The base demand forecast projects the number of natural gas customers will increase at a rate of 0.9 percent per year on average between 2024 and 2050, reaching 1.133 million customers by the end of the forecast period for the system. Overall, customer growth is slower than the 1.0 percent average annual growth rate projected in the 2021 IRP for 2022–2041.

Residential customer counts drive the growth in total customers since this class makes up, on average, 94 percent of PSE's natural gas sales customers. In the base demand forecast, we expect the number of residential customers to grow at an average annual rate of 0.9 percent from 2024 to 2050 (see Table D.1). The next largest group, commercial customers, is expected to grow at an average annual rate of 0.2 percent over the same time. We expect industrial and interruptible customer classes to continue to shrink, consistent with historical trends.

Table D.1: December Natural Gas Customer Counts by Class
2023 Gas Utility IRP Base Demand Forecast

Customer Type	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Residential	837,050	892,262	938,133	982,658	1,027,267	1,070,074	0.9
Commercial	58,015	59,013	59,764	60,285	60,748	60,896	0.2
Industrial	2,213	2,110	2,024	1,938	1,852	1,766	-0.9
Total Firm	897,278	953,385	999,921	1,044,881	1,089,867	1,132,736	0.9
Interruptible	124	88	58	28	9	9	-9.1
Total Firm & Interruptible	897,402	953,473	999,979	1,044,909	1,089,876	1,132,745	0.9
Transport	220	220	220	220	220	220	0.0
System Total	897,622	953,693	1,000,199	1,045,129	1,090,096	1,132,965	0.9

2.6.2. Natural Gas Use per Customer – Base Demand Forecast

Table D.2 below shows all firm use per customer at the meter. Residential use per customer, in the base demand forecast, before DSR is declining, showing a -0.4 percent average annual growth for the forecast period. We expect commercial use per customer to rise slowly at 0.3 percent annually over the forecast horizon due to assumptions about increases in employment. Industrial use per customer has been declining in recent years, and we expect it will continue to decline at -0.4 percent average annual growth. The commercial and industrial classes in the table below do not include interruptible or transport class usage. These classes can have different-sized customers, and very large customers can skew the use per customer value.

Table D.2: Natural Gas Use per Customer before Additional DSR
2023 IRP Gas Base Demand Forecast (therms/customer)

Customer Class	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Residential	713	689	675	667	651	644	-0.4
Commercial	4,919	5,002	5,089	5,184	5,223	5,296	0.3
Industrial	9,474	9,132	8,978	8,859	8,651	8,543	-0.4

2.6.3. Natural Gas Demand by Class – Base Demand Forecast

In the base demand forecast we expect total energy demand, including transport, to increase at an average rate of 0.5 percent annually between 2024 and 2050. Residential demand, which we forecast to represent 50 percent of demand in 2024, is expected to increase on average by 0.6 percent annually during the forecast period. Commercial demand, which we forecast to represent 24 percent of demand in 2024, is expected to increase by 0.4 percent on average.

Population growth is driving residential demand growth. Commercial demand growth is driven by increases in customer counts and use per customer. We expect demand in the industrial and interruptible sectors to decline as manufacturing employment in the Puget Sound area continues to slow (see Table D.3). We expect demand from the transport class to grow by 0.9 percent annually over the forecast period, mainly due to the increase in usage by a small number of customers.

Table D.3: Natural Gas Energy Demand by Class, Base Demand Forecast before Additional DSR (MDth)

Customer Type	2024	2030	2035	2040	2045	2050	AARG 2024-2050 (%)
Residential	59,284	61,084	62,951	65,172	66,495	68,610	0.6
Commercial	28,783	29,695	30,527	31,275	31,705	32,239	0.4
Industrial	2,129	1,959	1,850	1,749	1,634	1,541	-1.2
Total Firm	90,196	92,739	95,328	98,196	99,834	102,390	0.5
Interruptible	2,873	2,099	1,458	794	259	258	-8.4
Total Firm and Interruptible	93,069	94,838	96,786	98,989	100,093	102,648	0.4
Transport	24,183	27,741	28,219	28,771	29,375	30,226	0.9
System Total before Losses	117,252	122,579	125,005	127,760	129,468	132,873	0.5
Losses	1,101	1,151	1,173	1,199	1,215	1,247	-
System Total	118,353	123,730	126,179	128,959	130,684	134,121	0.5

2.6.4. Natural Gas Customer Count and Energy Demand Share by Class – Base Demand Forecast

We show customer counts as a percent of PSE's total natural gas customers in Table D.4 and demand share by class in Table D.5.

Table D.4: Natural Gas Customer Count Share by Class, Base Demand Forecast

Customer Type	Share in 2024 (%)	Share in 2050 (%)
Residential	93.3	94.4
Commercial	6.5	5.4
Industrial	0.2	0.2
Interruptible	0.01	0.001
Transport	0.02	0.02

Table D.5: Natural Gas Demand Share by Class before Additional DSR, Base Demand Forecast

Customer Type	Share in 2024 (%)	Share in 2050 (%)
Residential	50.1	51.2
Commercial	24.3	24.0
Industrial	1.8	1.1
Interruptible	2.4	0.2
Transport	20.4	22.5
Losses	0.93	0.93

2.6.5. Natural Gas Customer Counts – Zero-customer Growth Demand Forecast

The zero-customer growth demand forecast projects the number of natural gas customers will increase at a rate of 0.1 percent per year on average between 2024 and 2050, with the entirety of this increase happening between 2024 and 2026. Some customer classes have declining counts over the time period, and this was not affected by the assumption of zero-customer growth.

Most of the customers on the gas system are residential customers, therefore when growth stops in 2026 the residential customers still dominate the customer counts, with 94 percent of PSE's natural gas sales customers. In the zero-customer growth demand forecast, we expect the number of residential customers to grow at an average annual rate of 0.1 percent from 2024 to 2050. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.02 percent over the same time. We expect industrial and interruptible customer classes to continue to shrink, consistent with historical trends.

Table D.6: December Natural Gas Customer Counts by Class
2023 Gas Utility IRP Zero-customer Growth Demand Forecast

Customer Type	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Residential	837,050	855,428	855,428	855,428	855,428	855,428	0.1
Commercial	58,015	58,289	58,289	58,289	58,289	58,289	0.02
Industrial	2,213	2,110	2,024	1,938	1,852	1,766	-0.9
Total Firm	897,278	915,827	915,741	915,655	915,569	915,483	0.1
Interruptible	124	88	58	28	9	9	-9.1
Total Firm & Interruptible	897,402	915,915	915,799	915,683	915,578	915,483	0.1
Transport	220	220	220	220	220	220	0.0
System Total	897,622	916,135	916,019	e	915,578	915,712	0.1

2.6.6. Natural Gas Use per Customer – Zero-customer Growth Demand Forecast

Table D.7 below shows all firm use per customer at the meter. Residential use per customer, in the zero-customer growth demand forecast, before DSR is declining, showing a -0.4 percent average annual growth for the forecast period. We expect commercial use per customer to rise slowly at 0.1 percent annually over the forecast horizon due to assumptions about increases in employment. Industrial use per customer has been declining in recent years, and we expect it will continue to decline at -0.4 percent average annual growth. The commercial and industrial classes presented in the table below do not include interruptible or transport class usage. These classes can have different-sized customers, and very large customers can skew the use per customer value.

Table D.7: Natural Gas Use per Customer before Additional DSR
2023 IRP Gas Zero-customer Growth Demand Forecast (therms/customer)

Customer Class	2024	2030	2035	2040	2045	2050	AARG 2024–2050 (%)
Residential	713	687	672	663	646	639	-0.4
Commercial	4,919	4,940	4,989	5,046	5,049	5,078	0.1
Industrial	9,474	9,132	8,978	8,859	8,651	8,543	-0.4

2.6.7. Natural Gas Demand by Class – Zero-customer Growth Demand Forecast

In the zero-customer growth demand forecast we expect total energy demand, including transport, to decrease at an average rate of 0.2 percent annually between 2024 and 2050. Residential demand, which we forecast to represent 50 percent of demand in 2024, is expected to decrease on average by 0.3 percent annually during the forecast period. Commercial demand, which we forecast to represent 24 percent of demand in 2024, is expected to increase by 0.1 percent on average.

The decline in residential demand is driven by decreasing usage, due to warming winter temperatures. Commercial demand growth is affected by both warming temperatures and an increase in employment, leading to a slight increase in commercial use per customer over time. We expect demand in the industrial and interruptible sectors to decline as manufacturing employment in the Puget Sound area continues to slow. We expect demand from the transport class to grow by 0.3 percent annually over the forecast period, mainly due to the increase in usage by a small number of customers between 2024 and 2026.

Table D.8: Natural Gas Energy Demand by Class, Zero-customer Growth Demand Forecast before Additional DSR (MDth)

Customer Type	2024	2030	2035	2040	2045	2050	AARG 2024-2050 (%)
Residential	59,284	58,761	57,476	56,701	55,244	54,611	-0.3
Commercial	28,783	29,008	29,220	29,460	29,422	29,599	0.1
Industrial	2,129	1,959	1,850	1,749	1,634	1,541	-1.2

Customer Type	2024	2030	2035	2040	2045	2050	AARG 2024-2050 (%)
Total Firm	90,196	89,728	88,546	87,910	86,301	85,751	-0.2
Interruptible	2,873	2,083	1,415	725	259	258	-8.5
Total Firm and Interruptible	93,069	91,811	89,961	88,636	86,560	86,008	-0.3
Transport	24,183	26,469	26,337	26,242	26,044	25,928	0.3
System Total before Losses	117,252	118,280	116,298	114,877	112,603	111,936	-0.2
Losses	1,101	1,110	1,092	1,078	1,057	1,051	-
System Total	118,353	119,390	117,390	115,956	113,660	112,987	-0.2

2.6.8. Natural Gas Customer Count and Energy Demand Share by Class – Zero-customer Growth Demand Forecast

We show customer counts as a percent of PSE's total natural gas customers in Table D.9 and demand share by class in Table D.10.

Table D.9: Natural Gas Customer Count Share by Class, Zero-customer Growth Demand Forecast

Customer Type	Share in 2024 (%)	Share in 2050 (%)
Residential	93.3	93.4
Commercial	6.5	6.4
Industrial	0.2	0.2
Interruptible	0.01	0.001
Transport	0.02	0.02

Table D.10: Natural Gas Demand Share by Class before Additional DSR, Zero-customer Growth Demand Forecast

Customer Type	Share in 2024 (%)	Share in 2050 (%)
Residential	50.1	48.3
Commercial	24.3	26.2
Industrial	1.8	1.4
Interruptible	2.4	0.2
Transport	20.4	22.9
Losses	0.93	0.93

3. Climate Change Assumptions

This IRP is the first time PSE incorporated climate change temperatures into the forecast of energy demand and peak demand. This section describes in detail how we calculated future temperature assumptions.

3.1. Energy Forecast Temperatures

Puget Sound Energy's demand forecasting models employ various thresholds of HDD, consistent with industry practices. Monthly HDD help estimate the weather-sensitive demand in the service area. Most of PSE's customer classes are weather sensitive, so our model assumed normal degree days for these classes. A HDD measures the heating severity, defined by the distance between a base temperature and the average daily temperature. The UPC models we discussed use historical observations to derive UPC to HDD sensitivities, which we then forecasted forward with the normal assumption. Previously, PSE defined normal degree days as the monthly average of 30 years before the forecast was created. For example, the 2021 IRP normal definition spanned 1990–2019. For the 2023 Gas Utility IRP, we defined normal degree days as a rolling weighted average of the 15 years prior to the forecast year and 15 years after, including the forecast year. Values for the years after historical actuals are from three climate change models provided by the Northwest Power and Conservation Council (NWPCC). The new definition results in warmer winters, thereby decreasing total heating demand. The net effect of these assumptions for every year in the forecast is negative. What follows is how we calculated future degree days.

We defined Heating Degree Days $\boldsymbol{HDD_{M,Base,t}}$ for a scenario (M), base temperature, and observation time (t) as:

$$\mathbf{HDD_{M,Base,t}} = \sum_{d=1}^{\mathrm{Days_t}} \max\left(0, \mathrm{Base\ Temp_t} - \mathrm{Daily\ Avg\ Temp_{d,M}}\right)$$

To calculate normal HDD, we collected historical actual degree days and weighted averages of the future degree day model for a period using the following data set:

$$\mathbf{HDD_{Base,t}} = \begin{cases} \mathbf{HDD_{Actuals4,Base,t}} \text{ for } t < \text{Jan 2021} \\ \mathbf{\frac{1}{3}}\left(\mathbf{HDD_{CanESM2,Base,t}} + \mathbf{HDD_{CCSM4,Base,t}} + \mathbf{HDD_{CNRM-CM5_{MACA},Base,t}}\right) \text{for } t > \text{Dec 2020} \end{cases}$$

To calculate normal degree days, $\boldsymbol{DDN_T}$, we calculated the average of monthly degree days for the 15 years prior and 15 years forward, using actual temperature data or the weighted average of the models.

$$\mathbf{DDN_T} = \mathbf{\frac{1}{30}} \sum_{t=T-15}^{T+14} \mathbf{HDD_{Base,t}} \text{ , T = Jan 2024 – Dec 2050}$$

3.2. Design Temperature for Peak Forecast

The gas design peak in the 2021 IRP was a 52-heating-degree day (13 degrees Fahrenheit average temperature for the day). This gas utility planning standard was based on the coldest annual daily temperature from 1950–2019 and was the 1-in-50, or 98th percentile, of historic peak events.

The new gas design peak is also a 52-heating-degree day (13 degrees Fahrenheit average temperature for the day). The new design peak temperature uses historic data from 2010-2019 and climate data from three climate models for the years 2020 to 2049. This gas planning standard is still based on 1-in-50, or 98th percentile, the coldest annual daily temperature during that time. See Table D.11 for a comparison of the years used and the number of observations used in each calculation.

Table D.11: Comparison of Previous and Current Gas Utility Design Peak Temperature Calculations

Data Set	Years Used	Number of Observations	1-in-50 Daily Temperature (ºF)
Previous IRP	1950–2019	79	13
Current 2023 Gas Utility IRP (Includes Climate Change)	2010–2049	98	13

4. Stochastic Demand Forecasts

Demand forecasts are inherently uncertain, and to acknowledge this uncertainty, the 2023 Gas Utility IRP considers stochastic forecast scenarios. Examples of drivers of forecast uncertainty include future temperatures, customer growth, and usage levels. We created 250 stochastic monthly demand and peak forecasts to model these uncertainties for different IRP analyses.

Stochastic models estimate the probability of various outcomes while allowing for randomness in one or more inputs over time.

4.1. Monthly Demand and Peak Demand

The demand forecasts assumed economic, demographic, temperature, and model uncertainty to create the set of stochastic demand forecasts.

4.1.1. Economic and Demographic Assumptions

The econometric demand forecast equations depend on specific economic and demographic variables; these vary depending on whether the equation is for customer counts or UPC and whether the equation is for a residential or non-residential customer class. In PSE’s demand forecast models, the key service area economic and demographic inputs are population, employment, consumer price index (CPI), and manufacturing employment. These variables are inputs into one or more demand forecast equations.

We performed a stochastic simulation of PSE’s economic and demographic model to produce the distribution of PSE’s economic and demographic forecast variables to develop the stochastic demand simulations. Since these variables are a function of key U.S. macroeconomic variables such as population, employment, unemployment rate, personal income, personal consumption expenditure index, and long-term mortgage rates, we utilized the stochastic simulation functions in EViews[1] by providing the standard errors for the quarterly growth of key U.S. macroeconomic

[1] EViews is a popular econometric forecasting and simulation tool.

inputs into PSE's economic and demographic models. These standard errors were based on historical actuals from the last 30 years, ending in 2021. This created 1,000 stochastic simulation draws of PSE's economic and demographic models, which provided the basis for developing the distribution of the relevant economic and demographic inputs for the demand forecast models over the forecast period. We removed unrealistic outliers from the 1,000 economic and demographic draws. We then ran 250 draws through the gas utility demand forecast to create the 250 stochastic simulations of PSE's demand forecast.

4.1.2. Temperature

We modeled uncertainty in the levels of the heating load by varying future years' degree days and temperatures. We randomly assigned annual normal weather scenarios from three climate models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). We used weather data from these climate models from 2020 to 2049 in the stochastic simulations.

4.1.3. Model Uncertainty

The stochastic demand forecasts consider model uncertainty by adjusting customer growth and usage by normal random errors, consistent with the statistical properties of each class regression model. These model adjustments are consistent with Monte-Carlo methods of assessing regression models' uncertainty.

EXISTING RESOURCES AND ALTERNATIVES

APPENDIX E

PUGET SOUND ENERGY

Contents

1. Existing Resources

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

1.1. Existing Pipeline Capacity

There are two types of pipeline capacity. Direct-connect pipelines deliver supplies directly to Puget Sound Energy's (PSE) 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.

1.1.1. Direct-connect Pipeline Capacity

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

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

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 arrangement provides valuable flexibility, including sourcing natural gas from different regions daily in some contracts.

1.1.2. Upstream Pipeline Capacity

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

Figure E.1 shows a schematic of the natural gas pipelines for the Pacific Northwest. For the details of PSE's natural gas sales pipeline capacity, see Table E.1.

Figure E.1: Pacific Northwest Regional Natural Gas Pipeline Map

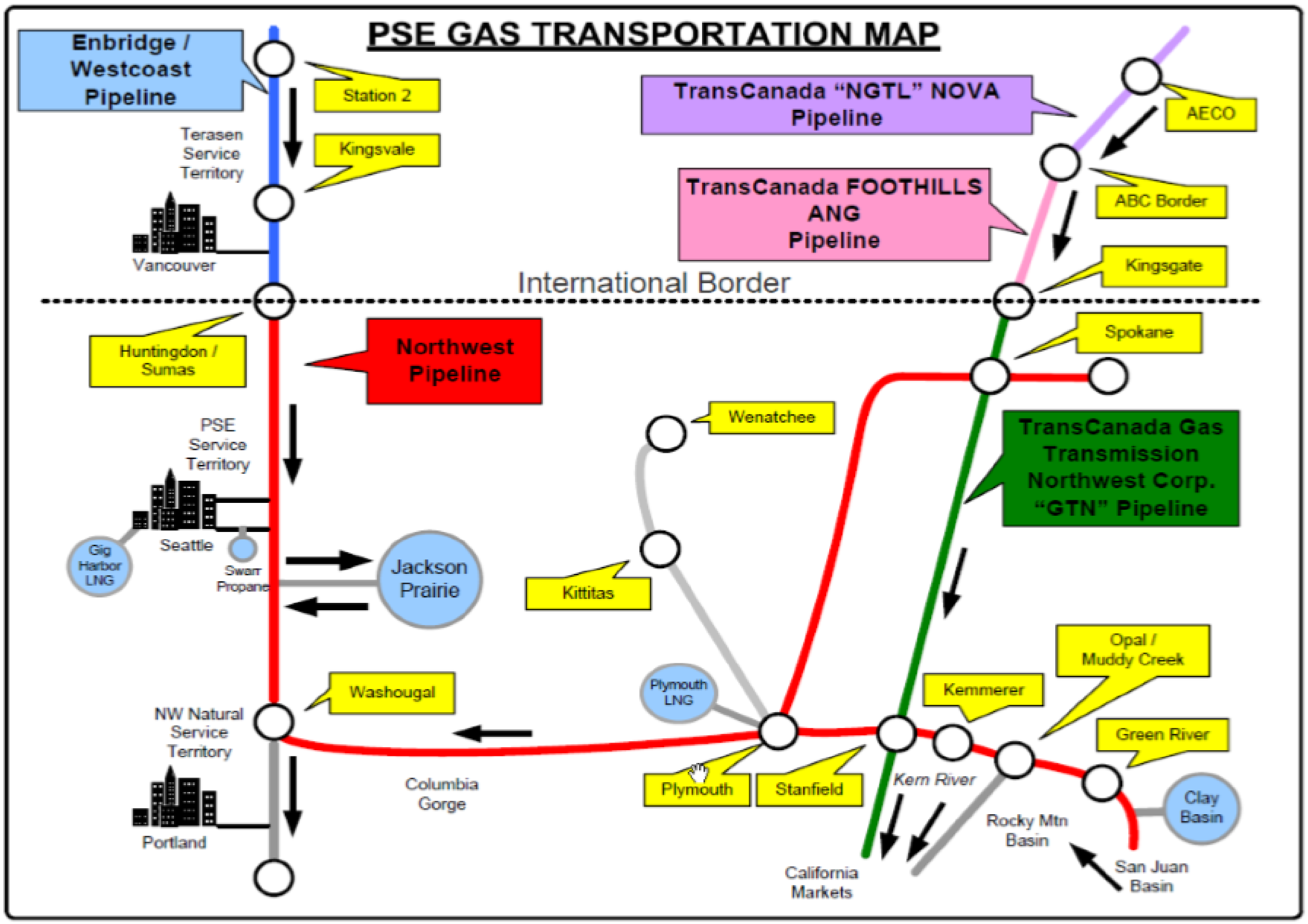


Table E.1: Natural Gas Sales — Firm Pipeline Capacity (Dth/day) as of 11/01/2020

Pipeline/Receipt Point	Total	2023–2028	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**
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	-

Pipeline/Receipt Point	Total	2023–2028	2028+
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. Northwest Pipeline (NWP) contracts have automatic annual renewal provisions, but PSE can cancel them with one year's notice.
2. Storage redelivery service (TF-2 or discounted TF-1) is 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. We converted the value to approximate Dth per day from the contract stated in gigajoules.
4. TC-GTN contracts have automatic renewal provisions, but PSE can cancel them with one year's notice.
5. We can use capacity alternatively to deliver additional volumes to Spokane.
6. We convert the value to approximate Dth per day from the contract in cubic meters per day. Westcoast adjusted the heat content factor up to reflect the higher Btu gas now normal on its system. This allows 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 unnecessary for a supply acquired at interconnects in the Rockies and supplies purchased at Sumas.

1.2. Transportation Types

This section discusses the pipeline contracts we use to transport gas from production areas to our city gate. The city gate connects to the delivery system in the PSE service areas. This discussion does not include delivery system pipelines.

1.2.1. TF-1 Contracts

TF-1 transportation contracts are firm contracts available every day of the year. We pay a fixed demand charge for the right but are not obligated to transport natural gas daily.

1.2.2. Storage Redelivery Service

Puget Sound Energy holds TF-2 and winter-only discounted TF-1 capacity under various contracts that provide 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.

1.2.3. Primary Firm, Alternate Firm, and Interruptible Capacity

Primary 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 selected delivery point. Firm transportation requires a fixed payment, whether the capacity is used or not, plus variable costs when physical gas is transported. Primary firm capacity is highly reliable when used in the contracted path from the receipt point to the delivery point.

Alternate Firm Capacity occurs when firm shippers have the right to temporarily alter the contractual receipt point, delivery point, and flow direction — subject to capacity availability for that day. This alternate firm capacity can be very reliable if the contract flows natural gas within the primary path, in the contractual direction to or from the primary delivery or receipt point. The alternate firm is much less reliable or predictable if used to flow natural gas in the opposite direction or out of the 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 their contracted firm transportation path.

If we can use firm transport in an alternate firm manner within or out of path and create segmented release capacity, we get low non-firm, interruptible volumes on the NWP system.

When we do not need the capacity to serve natural gas customers on a given day, we may use our 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, we may release capacity into the capacity release market. The company may also access additional firm capacity from the capacity release market temporarily or permanently when 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 we cannot rely on it to meet peak demand.

2. 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 considerable cost savings for the system and customers. Benefits include the following:

- Access to an immediate and controllable source of firm natural gas supply or storage space enables us to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage allows 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.

- We also use 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, Washington, is an aquifer-driven storage field located in the market area designed to deliver large quantities of natural gas over a relatively short period. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long natural gas supply. Table E.2 presents details about storage capacity.

Table E.2: Natural Gas Sales Storage Resources[1] as of 11/1/2020

Resource	Withdrawal Capacity (Dth/Day)	Injection Capacity (Dth/Day)	Storage Capacity (Dth)	Expiration Date
Jackson Prairie — PSE-owned	398,667	147,333	8,528,000	-
Jackson Prairie — PSE-owned[2]	(50,000)	(18,500)	(500,000)	2023
Net Jackson Prairie-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 available to PSE's electric generation portfolio (at a market-based price) from PSE's natural gas sales portfolio. We may be able to renew, depending on gas sales portfolio needs. We can recall firm withdrawal rights serving natural gas sales customers.
3. Northwest Pipeline contracts have automatic annual renewal provisions, but PSE can cancel them with one year's notice.
4. We expect to renew the Clay Basin storage agreements.
5. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio for 447,057 Dth/day.
6. Plus 50,000 Dth when Jackson Prairie is recalled from the electric portfolio.

2.1. Jackson Prairie Storage

As we show in Table E.2, PSE, NWP, and Avista utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which PSE operates as authorized by the Federal Energy Regulatory Commission (FERC). We own 398,667 Dth of firm withdrawal rights per day 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, we have access to 48,390 Dth per day of firm deliverability and associated firm storage capacity through an SGS-2F storage service contract with NWP. We hold 447,057 Dth of firm withdrawal rights per day for peak day use. We have 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts automatically renew yearly, but PSE has the unilateral right to terminate the agreement with one year's notice.

We use Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core natural gas customers — to meet seasonal load requirements, balance the daily load, and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

2.2. 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. Puget Sound Energy 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.

We use Clay Basin for certain baseload supply levels and backup supply in case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable supply source throughout the winter, including peak days, and 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.

2.3. Treatment of Storage Cost

Like firm pipeline capacity, firm storage arrangements require a fixed charge whether we use the storage service. We also pay 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 according to FERC-approved tariffs and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism. In contrast, we recover customers' costs associated with the PSE-owned portion of Jackson Prairie through base distribution rates. We recover some Jackson Prairie costs from PSE transportation customers through a balancing charge.

2.4. 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. A last resort due to their relatively higher variable costs, these resources typically help meet extreme peak demand during the coldest hours or days. These resources are not as flexible as other supply sources.

Table E.3: Natural Gas Sales Peaking Resources

Resource	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. 2025+
Tacoma LNG	85,000	2,100	538,000	On-system	Current
TOTAL	101,800	21,280	676,940	-	-

Notes:

1. Swarr is currently out of service pending upgrades to reliability, safety, and compliance systems. We may consider it in resource acquisition analysis for an in-service date in the latter part of the decade.

2. Swarr holds 1.24 million gallons. A refill rate of 111 gallons per minute takes 7.7 days or 16,680 Dth per day.

2.4.1. Gig Harbor Liquefied Natural Gas

Located in the Kitsap Peninsula Gig Harbor area, 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 is an incremental supply source, and we included its 2.5 MDth per day capacity 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.

2.4.2. Swarr Vaporized Propane-air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and is not currently configured to inject into the PSE system. 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 is underway to upgrade the facility's environmental, safety, and reliability systems and increase production capacity to 30,000 Dth per day. We evaluated the upgrades as a resource alternative for this plan in combination Nine — Swarr LP-Air Upgrade and assumed it would be available on three years' notice as early as the 2028–2029 winter. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

2.4.3. Tacoma Liquefied Natural Gas

The Tacoma LNG peak shaving facility came online in 2021 to serve the needs of core natural gas customers and regional LNG transportation fuel consumers. By serving new LNG fuel markets - primarily large marine consumers - the project achieved economies of scale and reduced 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 2023 Gas Utility IRP assumes we put the project in service late in the 2021–2022 heating season, providing 85 MDth per day of capacity — 66 MDth per day of vaporization, and 19 MDth per day of recalled natural gas supply.

2.4.4. Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations about natural gas supplies. Shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies as heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within its transportation and storage network limits, PSE maintains a policy of sourcing natural gas supplies from various 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 the NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. Although PSE depends heavily on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin, and Alberta. Our pipeline capacity on the NWP currently provides 50 percent of our flowing natural gas supplies to be delivered north of our service territory and the remaining 50 percent south of our service territory.

Price and delivery terms tend to be very similar across supply basins. However, 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. We expect comparable pricing across regional supply basins over the 20-year planning horizon, with differences in transportation costs and forecasted demand increases driving the differentials. We purchased the long-term supply pricing scenarios used in this analysis from 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.

We have always purchased our supply at market hubs. There are various transportation receipt points in the Rockies and San Juan basin, including Opal, Clay Basin, and Blanco. Alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers and marketers. Puget Sound Energy has several supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TC Energy's Nova (TC-NGTL) pipeline, TC Energy's Foothills pipeline, and TC Energy's Gas Transmission NW (TC-GTN) pipeline to the company's portfolio also increased our ability to access supply in the more price-liquid producing areas in Canada.

Natural gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with 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. We also contract for seasonal baseload firm supply, typically for the winter months, November through March. Near-term transactions supplement baseload transactions, particularly for the winter months. We estimate average load requirements for upcoming months and enter month-long or multi-month transactions to balance load. We offset daily positions with storage from Jackson Prairie, Clay Basin, day-ahead purchases, and off-system sales transactions. We use Jackson Prairies to balance intra-day positions. We continuously monitor natural gas markets to identify trends and opportunities to fine-tune our contracting, purchasing, and storage strategies.

2.4.5. Existing Demand-side Resources

Puget Sound Energy has provided demand-side resources to our customers since 1993. These energy efficiency programs operate following requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.[1] The programs primarily served residential and low-income customers through 1998. In 1999, we expanded them to include commercial and industrial customer facilities. We fund most natural gas energy efficiency programs using gas rider funds collected from customers.

[1] See WUTC Docket UG-011571.

Table E.4 shows that energy efficiency measures installed through 2021 have saved more than 6.6 million Dth, a reduction in CO_2 emissions of approximately 361,000 metric tons. We have achieved more than half of these savings since 2010. Savings per year have mostly ranged from 3 to 5 million therms, peaking at just over 6.3 million in 2013.

We establish energy savings targets and create programs to achieve those targets every two years. The 2020–2021 biennial program period concluded at the end of 2021. The current program cycle runs from January 1, 2022, through December 31, 2023, with a two-year energy savings target of approximately 7.4 million therms. This goal was based on an extensive analysis of savings potentials and developed in collaboration with key external interested parties in the Integrated Resource Plan (IRP) process and the Conservation Resource Advisory Group (CRAG).

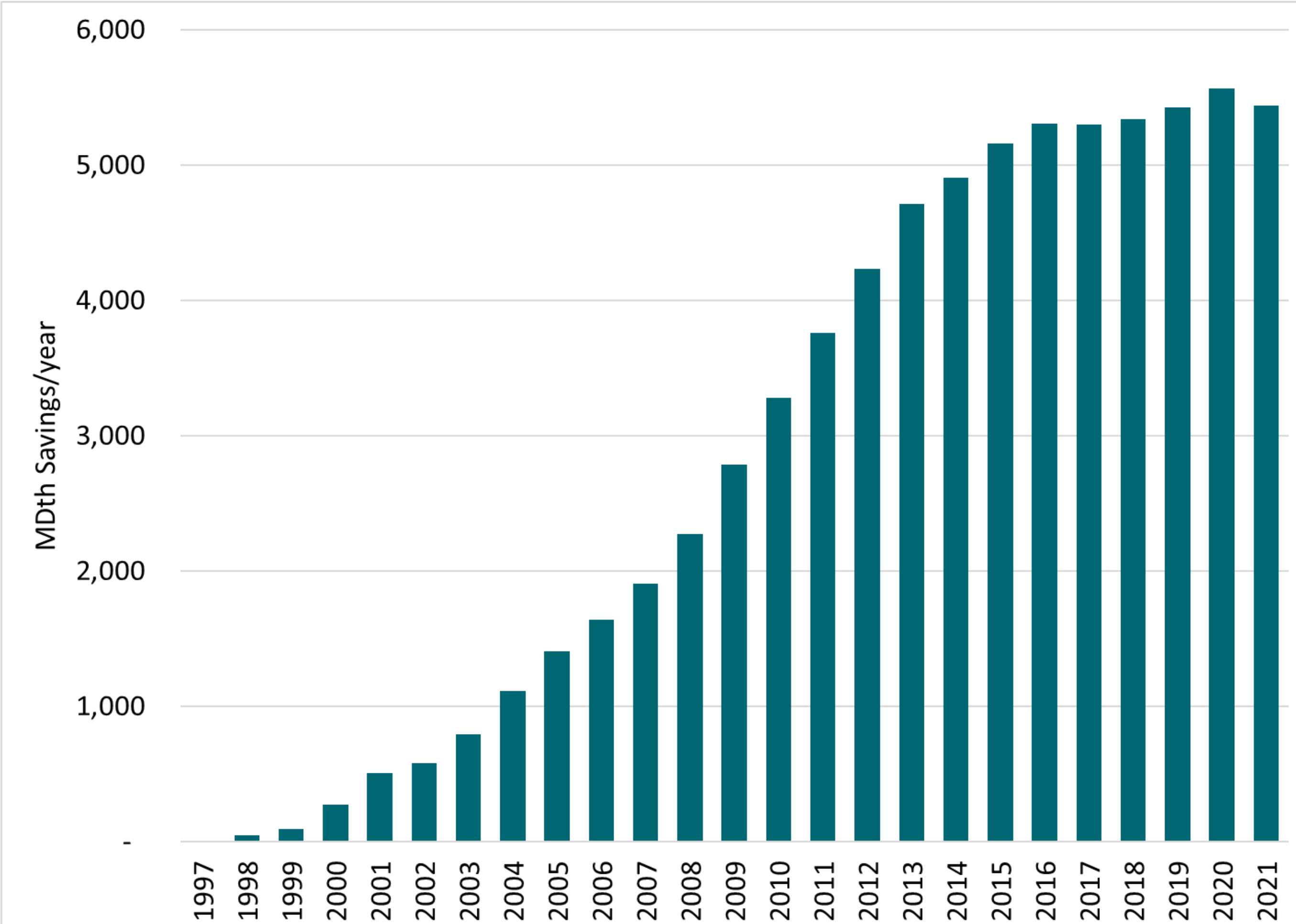
Puget Sound Energy spent more than $15.5 million for natural gas conservation programs in 2021 (the most recent complete program year) compared to $3.2 million in 2005. Spending over that period increased more than 35 percent annually. The low cost of natural gas and the rising cost of materials and equipment have pressured the cost-effectiveness of savings measures. We are collaborating with regional efforts to find creative ways to make the delivery and marketing of natural gas efficiency programs more cost-effective and to reduce barriers to promising measures that have not yet gained significant market share.

Table E.4 summarizes energy savings and costs for 2020–2023.

Table E.4: Natural Gas Sales Energy Efficiency Program Summary, 2020–2023
Total Savings and Costs

Program Year	Actual Savings (MDth)	Actual Cost ($ millions)	Target Savings (MDth)	Budget ($ millions)
2020	410.3	15.1	400	18.6
2021	236.4	15.8	338.9	19.4
2022-23	-	-	755.1	48.5

Figure E.2: Cumulative Natural Gas Sales Energy Savings from DSR, 1997–2021



3. Resource Alternatives

The natural gas sales resource alternatives considered in this plan address long-term capacity challenges under a changing policy landscape rather than the short-term optimization and portfolio management strategies PSE uses to minimize costs in the daily conduct of business.

3.1. Supply Side Resource Alternatives Considered

The driving force behind the process we used to develop this plan is the recently passed Climate Commitment Act (CCA) of 2021.[2] The CCA lays out a pathway to reducing emissions from gas utility operations that the Department of Ecology's (Ecology) rulemaking[3] will further define. We expanded the resource alternatives in this year's plan from previous Integrated Resource Plans to focus on emission compliance: renewable fuels such as biogases and green

[2] https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act

[3] https://ecology.wa.gov/Regulations-Permits/Laws-rules-rulemaking/Rulemaking/WAC-173-446

hydrogen, hybrid heat pumps, reducing (by not renewing) pipeline transport capacity where it makes sense to reduce sales portfolio costs, and energy efficiency.

Transporting natural gas from production areas or market hubs to PSE's service area entails assembling several specific pipeline segments and natural gas storage alternatives. We combined purchases from specific market hubs with various upstream and direct-connect pipeline alternatives and storage options to create versions that have different costs and benefits.

We have already contracted several renewable natural gas (RNG) sources and will explore the cost-effectiveness of more RNG resources to reduce emissions under the CCA. We are also working with outside parties in joint development agreements to explore hydrogen options for gas for power and sales loads. This 2023 Gas Utility IRP included green hydrogen options as a blending fuel to displace some natural gas.

Demand-side resources are a significant resource in our territory. Along with traditional energy-efficiency measures, our plan includes hybrid heat pumps as a conservation measure, significantly reducing gas use and emissions while providing backup fuel during peak winter periods. This approach minimizes the impact on the electrical grid while achieving significant reductions in emissions. Finally, this 2023 Gas Utility IRP includes impacts from full electrification in a scenario where we ramped the technically achievable amount of electrification[8] into the portfolio as a must-take resource over this plan's study period.

We grouped the alternatives into seven broad combinations for analysis purposes. We discussed these combinations in the next section. Note that demand-side resources are a different alternative discussed later in this chapter.

We use the following acronyms in the descriptions:

- 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 a gas with the same heating value as natural gas)
- NWP: Williams Northwest Pipeline, LLC pipeline
- TC-Foothills: TCEnergy-Foothills BC (Zone 8) pipeline
- TC-GTN: TCEnergy-Gas Transmission-Northwest pipeline
- TC-NGTL: TCEnergy-NOVA Gas Transmission Ltd. pipeline
- Westcoast pipeline: Enbridge's Westcoast Energy Inc. pipeline

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area are generally assembled from several specific segments and/or natural gas storage alternatives. We join purchases from specific market hubs with various upstream and direct-connect pipeline alternatives and storage options to create combinations with different costs and benefits. On-system resources can also serve as peaking resources; they do not require transport pipeline capacity to deliver them to the demand centers.

Given that the Climate Commitment Act (CCA) is in effect, the existing supply resources will likely be adequate to serve the demand over the study period. The more likely trend will be a downward trajectory for the demand leading to surplus supply-side resources. This plan looks to optimize supply-side resources to minimize the system cost while meeting the emissions obligations under CCA and ensuring enough resources to serve ratepayers on peak winter days. This optimization includes reviewing transport pipeline contract renewals and potentially replacing pipeline capacity with on-system or storage resources, where we can bring such resources at a lower cost to the portfolio. When we reduce the volume of year-round available pipeline capacity relative to existing or increased storage capacity, we also need to verify that the new resource portfolio has adequate capacity to serve customer needs during winters that are colder than average — most peaking resources are only available for a few days per year. We must determine this before concluding that the revised portfolio is acceptable.

We analyzed nine supply-side alternatives in this plan.

3.1.1. Alternatives One–Six: Northwest Pipeline Renewals

Several contracts on the Northwest Pipeline (NWP) will be up for renewal after 2024 and within the 2023 Gas Utility IRP study period. Given that energy efficiency and hybrid heat pumps will reduce demand, it may be more cost-effective to reduce or allow to terminate (turn-back) some of the pipeline contracts to better align with the demand.

The renewals on the NWP are segments connecting all three major gas supply hubs: Sumas/Station 2, Rockies, and AECO. Table E.5 shows the timing of the contracts offered as renewal options in the portfolio model, an aggregation of contracts on that segment.

Table E.5: Timeline of Pipeline Capacity Offered for Renewal

Segment in Daily MDth	Hub	Nov 2024	Nov 2028	Nov 2030	Nov 2033
Sumas to PSE	Sumas	X	-	-	-
Sumas to PSE	Sumas	-	X	-	-
Sumas to PSE	Sumas	-	-	X	-
Opal to Stanfield	Rockies	X	-	-	-
Opal to Stanfield	Rockies	-	X	-	-
Starr Rd to Plymouth	AECO	-	-	-	X

3.1.2. Alternative Seven: Plymouth Liquefied Natural Gas with Firm Delivery

This option includes 60 MDth capacity with a 15 MDth per day firm withdrawal of Plymouth LNG service and 15 MDth per day of primary firm NWP capacity from the Plymouth LNG plant to PSE. Puget Sound Energy's electric power generation portfolio currently holds this resource, which may be available for a one-time renewal in April 2024. Although this is a valuable resource for the power generation portfolio, it may better fit the natural gas sales portfolio and is offered in April 2024.

3.1.3. Alternative Eight: Swarr Vaporized Propane-air Upgrade

Alternative eight is an upgrade to the existing Swarr LP-Air facility. The upgrade would increase the peak day planning capability from 10 MDth to 30 MDth daily. This plant is located within PSE's distribution network and could be available on three years' notice as early as winter 2028/29. We offered this alternative in 2028–2029, 2029–30, and 2030–31.

We considered two fuels to achieve CCA compliance: renewable natural gas (RNG) and green hydrogen.

3.1.4. Alternatives 9–15: Renewable Natural Gas

We considered seven renewable natural gas combinations in the portfolio analysis.

Table E.6: Timeline of Pipeline Capacity Offered for Renewal

Combination	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Year Offered
9	RNG-physical N-1	WA	Sumas	1600	2024
10	RNG-physical N-2	WA	Sumas	1388	2025
11	RNG Attribute-1	N America	Sumas	3000	Annual
12	RNG Attribute-2	N America	Sumas	1000	Annual
13	RNG Attribute-3	WA	Stanfield	340	2024
14	RNG Attribute-4	N America	Sumas	8000	Annual
15	RNG- physical O-1	WA	On system	70	2024

3.1.5. Alternatives 16–18: Green Hydrogen

We have been working with various parties to jointly assess the development of an electrolyzer-based facility that will use renewable electricity to produce green hydrogen. We based this combination on green hydrogen used to blend into the gas distribution system, simultaneously displacing pipeline capacity on Northwest Pipeline. It assumes three combinations: a 5 percent blend by volume starting in 2028, an additional 5 percent in 2030, and a final 5 percent in 2032, for 15 percent blended green hydrogen by volume in the gas system.[4]

4. Supply and Demand-side Resource Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project. Puget Sound Energy also contracts for capacity at the Clay Basin storage facility in northeastern Utah. Additional pipeline capacity from Clay Basin is unavailable, and we are not considering storage expansion. In this plan, we did not analyze expanding storage capacity at Jackson Prairie and do not believe we can mitigate the potential risks from expansion in the long run.

We considered the following storage alternatives for this plan.

4.1. Swarr and Plymouth LNG plant

We discuss the Swarr LP-Air facility in the Existing Peaking Supply and Capacity Resources section. We are evaluating this resource alternative and are in the preliminary stages of designing the upgrade to Swarr's environmental, safety,

[4] 15 percent hydrogen by volume will displace approximately 5 percent of conventional natural gas in energy.

and reliability systems and increasing production capacity to 30,000 Dth per day. We assumed the facility would be available on three years' notice for the 2028–2029 heating season.

Table E.7: Natural Gas Storage Alternatives Analyzed

Storage Alternatives	Description
Swarr LP-Air Facility Upgrade (Alternative 8)	Considers the timing of the planned upgrade for reliability and increased capacity (from 0 MDth/day to 30 MDth/day) beginning the 2028-29 heating season.
Plymouth LNG contract with NWP firm transportation (Alternative 7)	Considers acquisition of an existing Plymouth LNG contract and associated firm transportation for 15 MDth/day, beginning April 2024.

4.2. Natural Gas Supply Fuel Alternatives

As described earlier in this chapter, we expect natural gas supply and production to continue to expand in northern British Columbia and the Rockies as operators develop shale and tight gas formations using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, we anticipate that adequate natural gas supplies will be available to support existing pipeline infrastructure from northern British Columbia via Westcoast or TC-NGTL, TC-Foothills, and TC-GTN or from the Rockies basin via NWP.

4.2.1. Renewable Natural Gas

Renewable natural gas (RNG) is pipeline-quality biogas that we can substitute for conventional gas streams. Renewable gas is captured from dairy waste, wastewater treatment facilities, and landfills. The American Biogas Council ranks Washington State twenty-second in the nation for methane production potential from biogas sources, with the potential to develop 128 new projects within the state. Renewable natural gas costs more than conventional 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 gas that it replaces.

Renewable Natural Gas is not yet produced at utility-scale in this region and will require developing supply sources and an infrastructure to deliver that supply to utilities. Market forces will likely direct RNG to gas utilities before we use it to generate energy. The electric sector has access to more mature renewable options that capture surplus energy than the gas sector. These options include hydro, wind, solar, geothermal, and energy storage systems. Gas utilities have few opportunities to decarbonize, so as they begin decarbonizing their systems in earnest, markets will probably pull RNG to gas utilities before it is used broadly as a generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is used chiefly as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, gas utilities can use the existing distribution network to deliver renewable fuel. This 2023 Gas Utility IRP analyzes local and national sources of RNG projects that would connect to the Northwest Pipeline (NWP) or PSE's system and displace conventional gas that would otherwise flow on NWP capacity. With the additional costs on carbon because of the Climate Commitment Act, the high cost of RNG may no longer be a barrier to leveraging the fuel source within the gas utility portfolio under specific scenarios.

We measure the benefits of RNG primarily in carbon dioxide equivalent (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. We will consider avoided pipeline charges realized by the connection of acquired RNG directly to the PSE system, but these savings 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, we are not prepared to publicly discuss specific potential RNG projects. We will analyze and document individual projects as we pursue additional supplies.

The Washington State legislature passed HB 1257, effective in July 2019, state officials also incorporated HB 1257 in the Washington Utilities Transportation Commission (Commission) RNG Policy Statement[5] issued in December 2020. Puget Sound Energy conducted an RFI (request for information) to determine the availability and pricing of RNG supplies. After analysis and negotiation, we acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. We are providing RNG under a voluntary RNG program for PSE customers. We will incorporate RNG supply not utilized in PSE's voluntary RNG program(s) into our supply portfolio, displacing natural gas purchases as provided in HB 1257.

This 2023 Gas Utility IRP does not analyze hypothetical RNG projects connecting to the NWP or PSE's system and displacing conventional natural gas that would otherwise flow on NWP pipeline capacity. However, because of RNG's significantly higher cost, the minimal availability of sources, and the unique nature of each project, RNG is not suitable for generic analysis. We measure the benefits of RNG in 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. We will consider avoided pipeline charges realized by connecting acquired RNG directly to the PSE system, but this is 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, we are not prepared to publicly discuss specific potential RNG projects. We will analyze and document individual projects as we pursue additional supplies.

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 our natural gas system annually. We are planning significant investments in cost-effective RNG supplies and believe that being a proactive RNG buyer and producer in the region is valuable. We are confident we can acquire sufficient RNG volume to meet the needs of our future voluntary RNG program participants. We believe PSE will exceed the 5 percent cost limitation related to the RNG incorporated into the supply portfolio.[6] To meet the expectations in the Commission RNG policy statement, we will use staggered RNG supply contracts and project development timelines, resales in compliance

5 https://www.utc.wa.gov/casedocket/2019/190818/docsets

6 U-190818 – Policy Statement – RNG

markets, and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

4.2.2. Green Hydrogen

Operators create green hydrogen 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 via truck, pipeline, or rail to end users, while 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.

Although hydrogen has always held promise as a clean energy source, the economics have historically been unfavorably compared to fossil fuels. The increasing adoption of grid-scale renewable power and the associated dislocation of supply and demand has altered the economic landscape for hydrogen over the last decade. As more renewables became connected, the frequency and duration of grid congestion increased, resulting in idled renewable power. Using that surplus of electricity to create hydrogen not only increases the capacity factor of the renewable resource but also allows for the seasonal storage of electricity, as hydrogen can be created when power is cheapest and used weeks or months later in a fuel cell or power plant when peak electrical demand calls require a dispatchable resource.

We are investigating supplier relationships and developing strategies to procure green hydrogen to support our natural gas operations' decarbonization and power generation portfolio. Creating green hydrogen relies on green power, providing a revenue-generating opportunity for PSE by installing new renewable sources and associated electrical infrastructure investments.

In the natural gas distribution system, PSE aims to inject green hydrogen directly into the system in the early 2030 timeframe. We are currently studying the technical and operational limits of hydrogen blending and anticipate an upper hydrogen limit of 15 percent by volume. Based on historical gas volumes in the system, this equates to an annual hydrogen consumption of approximately 41,000 tonnes. The blending strategy that is currently under development will address the technical and operational characteristics of blending hydrogen, including the location of third-party electrolyzers, hydraulic characteristics of the gas distribution system, hydrogen storage, and impact on the electrical grid. We do not expect the industrial supply of green hydrogen to materialize in the region until 2028, and the ramp-up to a full 15 percent blend will likely take several years.

Initial interest in power purchases for electrolyzers indicates that adequate regional supplies will support peak power generation and gas blending by up to 15 percent in the future. This interest and regulatory and political support appear to have created the conditions to move this energy source from the fringes to a mainstream commodity over the next 20 to 30 years. Over the short term, we will continue to study market developments, engage with developers, and support adoption to ensure the gains are permanent and long-lasting.

This plan assumes an electrolyzer plant that would come on line in the 2028 winter period and provide 5 percent of the blend volume, then another 5 percent in 2030, and another 5 percent in 2032 for a total of 15 percent by volume of blending into the gas distribution system. We relied on assumptions in the E3 Pacific Northwest report[7] as the basis for the cost curve for developing electrolyzer-based green hydrogen.

4.3. Demand-side Resource Alternatives

We first conduct a conservation potential assessment to develop demand-side alternatives for portfolio analysis. This study reviews existing and projected building stock and end-use technology saturations to estimate possible savings by installing more efficient commercially available technologies. The broadest savings measure from making these installations (or replacing old technology) is called the technical potential. This is 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 achievable levels when accounting for market barriers. To be consistent with electric measures, we assumed that all natural gas retrofit measures' achievability factors are 85 percent. Like electric measures, all natural gas measures receive a 10 percent conservation credit from the Power Act of 1980. We then organized the measures into a conservation supply curve, from lowest to highest levelized cost.

Next, we grouped individual measures on the supply curve into cost segments called bundles. For example, all measures with a levelized cost between $2.2 per Dth and $3.0 per Dth may be grouped into bundles and labeled Bundle 2. In the 2021 Gas Utility IRP, the highest cost bundle was Bundle 12, and this was a catch-all bundle with all measures costing above $15 per Dth. Initial portfolio runs showed that bundle 11 was the most cost-effective. Thus, we decided to expand bundle 12 into smaller segments. As a result, there are eighteen bundles in this plan.

From:

- Bundle 12: >$1.50/Th

To:

- Bundle 12: $1.50/Th–$1.75/Th
- Bundle 13: $1.75/Th–$2.00/Th
- Bundle 14: $2.00/Th–$2.25/Th
- Bundle 15: $2.25/Th–$2.50/Th
- Bundle 16: $2.50/Th–$2.75/Th
- Bundle 17: $2.75/Th–$3.00/Th
- Bundle 18: >$3.00/Th

The codes and standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that take effect at a future date. This bundle is always selected in the portfolio, effectively representing a reduction in the load forecast.

[7] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Figure E.8 shows the price bundles and corresponding savings volumes in the achievable technical potential developed for this plan. The bundles are shown in dollars per therm, and the savings for each bundle demonstrated in 2033 and 2050 are in thousand dekatherms per year (MDth/year). We developed these savings using PSE's weighted average cost of capital (WACC) as the discount rate.

We are trying to acquire as many cost-effective natural gas demand-side resources as we can as quickly as possible. We can alter the acquisitions or ramp rate of natural gas sales DSR by changing the speed at which we acquire discretionary DSR measures. In these bundles, the discretionary measures assume a 10-year ramp rate; they are acquired during the first 10 years of the study period. Because of this acceleration, there is a drop off in savings after the tenth year.

Table E.8: Natural Gas DSR Cost Bundles and Savings Volumes (MDth/year)

Bundle	2033	2050
Codes & Standards ($)	2,751	6,744
Bundle 1: <0.22	1,252	1,822
Bundle 2: 0.22–0.30	1,288	1,894
Bundle 3: 0.30–0.45	1,371	2,155
Bundle 4: 0.45–0.50	1,373	2,158
Bundle 5: 0.50–0.55	1,853	2,686
Bundle 6: 0.55–0.62	1,903	3,177
Bundle 7: 0.62–0.70	2,386	3,770
Bundle 8: 0.70–0.85	3,568	6,594
Bundle 9: 0.85–0.95	3,613	6,675
Bundle 10: 0.95–1.20	4,198	7,708
Bundle 11: 1.20–1.50	4,735	8,493
Bundle 12: 1.50–1.75	5,893	11,145
Bundle 13: 1.75–2.00	5,979	11,276
Bundle 14: 2.00–2.25	6,219	11,587
Bundle 15: 2.25–2.50	6,360	11,793
Bundle 16: 2.50–2.75	6,511	11,984
Bundle 17: 2.75–3.00	6,704	12,322
Bundle 18: 3.00–99.00	9,477	16,499

➔ See Appendix C: Conservation Potential Assessment for more detail on the measures, assumptions, and methodology used to develop DSR potentials.

In the final step, we used the natural gas portfolio model (GPM) to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, we further divided the cost bundles by market sector and weather and non-weather-sensitive measures. We added increasingly expensive bundles to each scenario until the GPM rejected bundles were as not cost-effective. The bundle that significantly reduced the portfolio cost was deemed the appropriate level of demand-side resources for that scenario. Figure E.3 illustrates the methodology described above.

Figure E.3: General Methodology for Assessing Demand-side Resource Potential

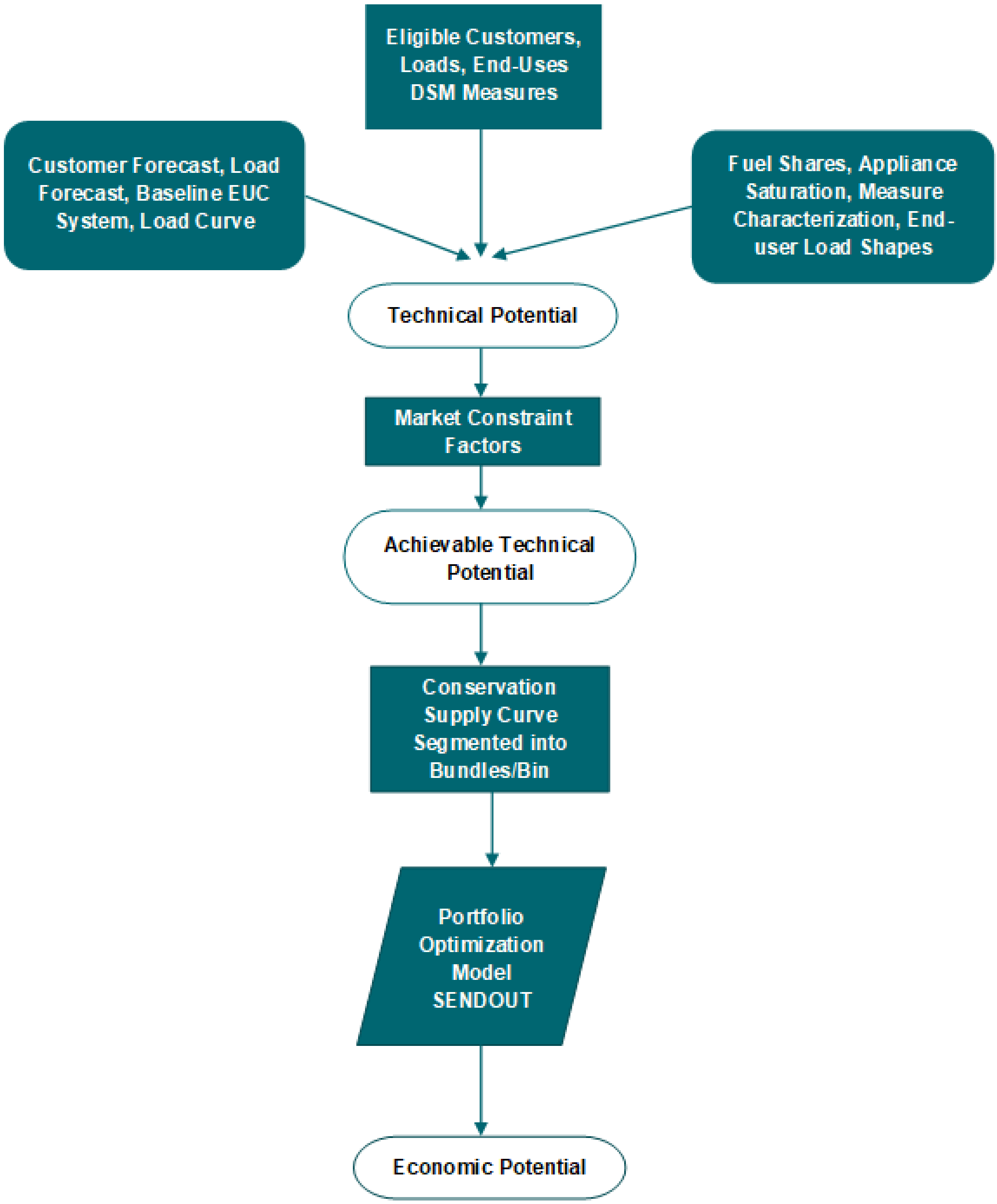


Figure E.4 shows the range of achievable technical potential among the eighteen cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the optimal level of demand-side natural gas resource for a particular scenario.

Figure E.4: Demand-side Resources — Achievable Technical Potential Bundles

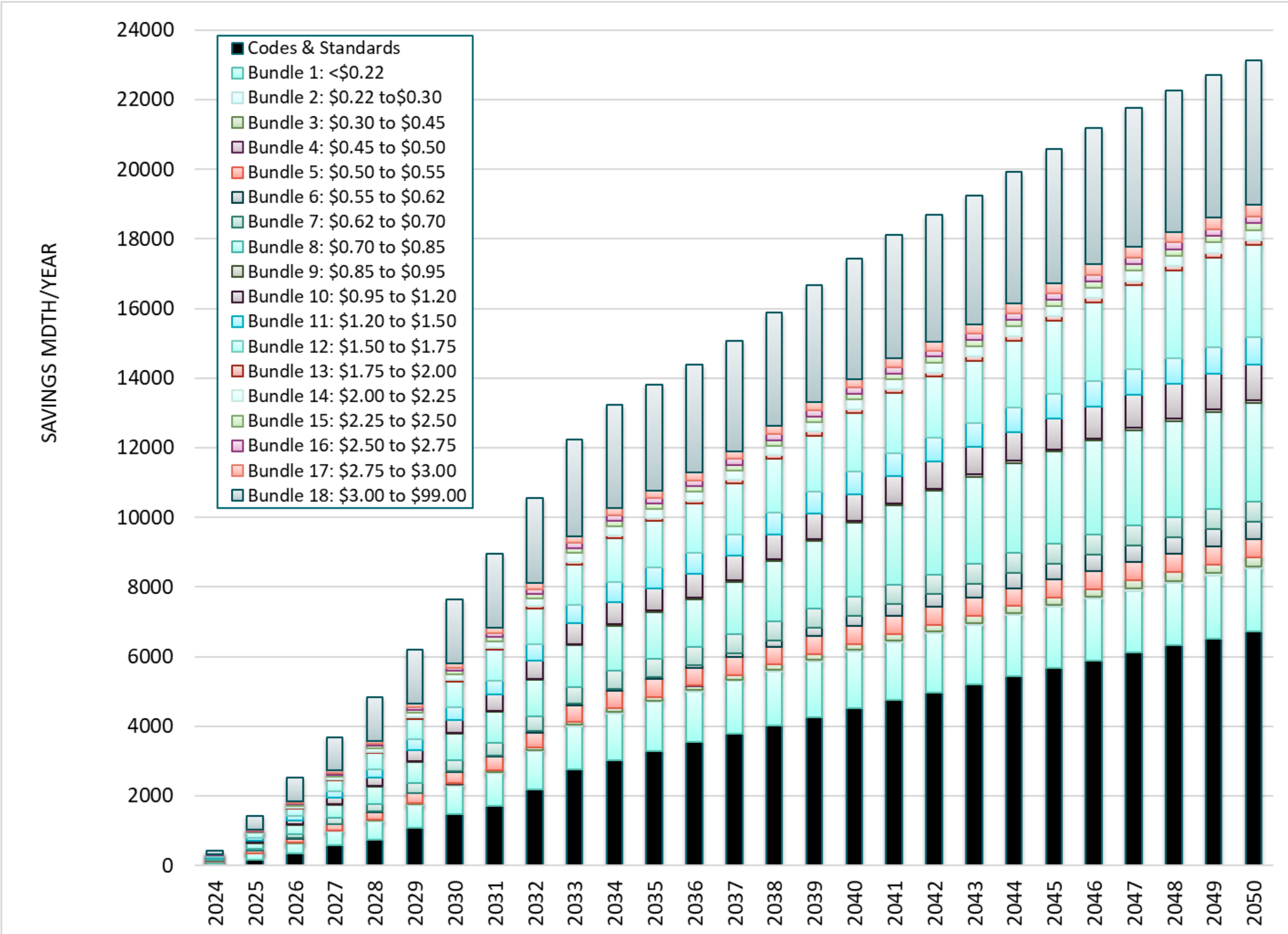


Figure E.5 shows DSR savings subdivided by customer class. We used this input format in the GPM for all bundles in the 2023 Gas Utility IRP scenarios.

Figure E.5: Savings Formatted for Portfolio Model Input by Customer Class

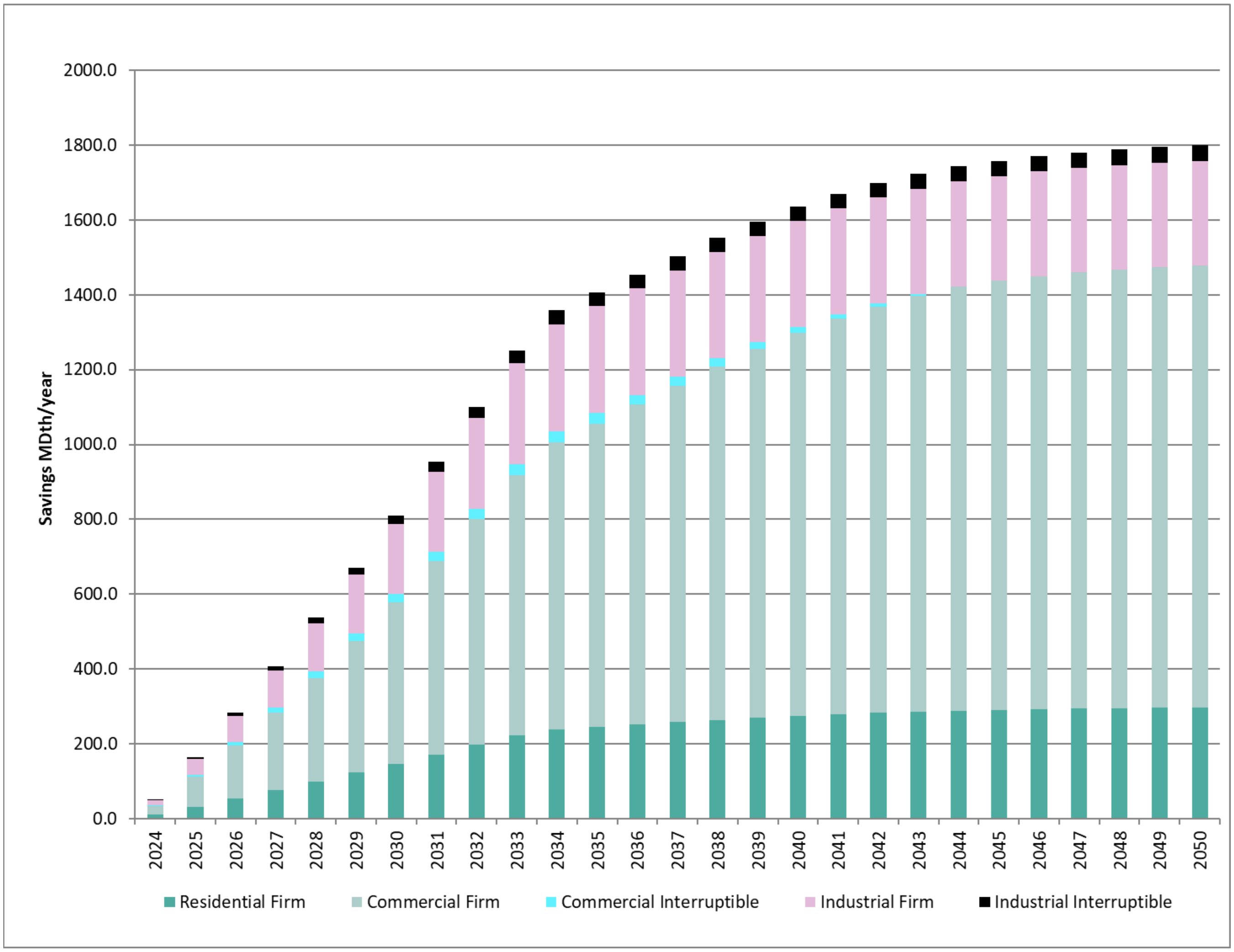


Table E.9 shows DSR savings for transport customers who emit under 25,000 tons of carbon dioxide, which we included per the requirements of the CCA. These customers only use and pay for the delivery service on their distribution system and were not included in the portfolio modeling. The CPA consultant had an estimate of the energy efficiency available from these customers and provided a top-down energy efficiency potential for PSE. As very little information on end uses and loads is available to PSE, a more detailed study to determine the energy efficiency potential is warranted later per the CCA program requirements. The CPA consultant provided an economic screening based on the proxy avoided costs using the expected or mid-allowance carbon price, the social cost of greenhouse gases (SCGHG), and 2023 gas commodity costs.

Table E.9: Conservation Potential for Transport Customers with under 25,000 tons of Carbon (MDth/Year)

Description	2033	2050
Codes & Standards	0	0
Bundle 1: <$0.22	1,771	2,503
Bundle 2: $0.22 to$0.30	1,814	2,614

Description	2033	2050
Bundle 3: $0.30 to $0.45	1,957	3,481
Bundle 4: $0.45 to $0.50	1,959	3,492
Bundle 5: $0.50 to $0.55	1,961	3,509
Bundle 6: $0.55 to $0.62	1,979	3,619
Bundle 7: $0.62 to $0.70	2,017	3,677
Bundle 8: $0.70 to $0.85	2,044	3,728
Bundle 9: $0.85 to $0.95	2,048	3,734
Bundle 10: $0.95 to $1.20	2,075	3,799
Bundle 11: $1.20 to $1.50	2,322	5,320
Bundle 12: $1.50 to $1.75	2,357	5,526
Bundle 13: $1.75 to $2.00	2,367	5,549
Bundle 14: $2.00 to $2.25	2,381	5,667
Bundle 15: $2.25 to $2.50	3,575	8,842
Bundle 16: $2.50 to $2.75	3,680	9,686
Bundle 17: $2.75 to $3.00	3,702	9,711
Bundle 18: $3.00 to $99.00	3,764	9,970

5. Climate Commitment Act — Electrification Scenarios

We studied various_electrification scenarios to reduce emissions as mandated by the CCA. These combine gas conservation measures using hybrid heat pumps and direct conversion from gas to electric. We developed three scenarios in the CPA for input to this plan's analysis:

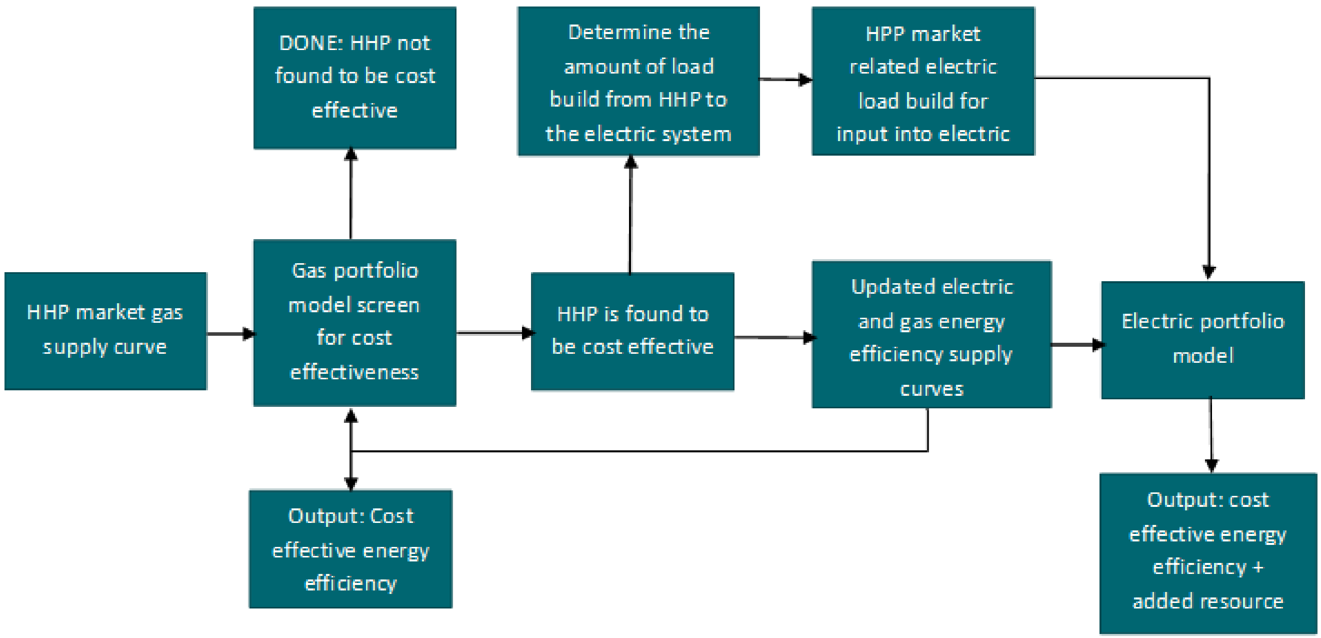
- Full electrification policy
- Hybrid Heat Pump (HHP) market
- Hybrid Heat Pump (HHP) policy

HHP Market: In this scenario, the CPA developed a supply curve using dual-fuel or hybrid heat pumps for space heating that uses gas for cold weather heating below 35ºF when electric strip heating normally supports heating in a heat pump. This approach avoids the peak day spike on the electric grid from the electric strip heating element in a fully electric heat pump. Electric peak would require additional infrastructure investment on the electric grid to accommodate this peak load. Instead, the peak in an HHP is on the gas side, which the current infrastructure can accommodate.

We added the HHP market supply curve in the gas model with all the measured costs, and the gas model screened it for cost-effectiveness. The cost-effective level from the gas model then informs the electric load builds we incorporate in the electric portfolio analysis and the adjustments we need to the electric and gas energy efficiency supply curves.

Figure E.6 shows the process flow for developing the appropriate, cost-effective energy efficiency and the load impacts on the gas and electric systems.

Figure E.6: Analytical Process for Evaluating HHP Market Options in the Gas and Electric System



HHP Policy: In this scenario, the CPA developed a supply curve that would electrify the gas end uses upon end-of-life replacement of end-use gas equipment. This scenario used dual-fuel or hybrid heat pumps for residential space heating that works as described above.

Unlike the HHP market scenario, the HHP policy adds some electric peak demand and keeps a gas peak load from the HHP:

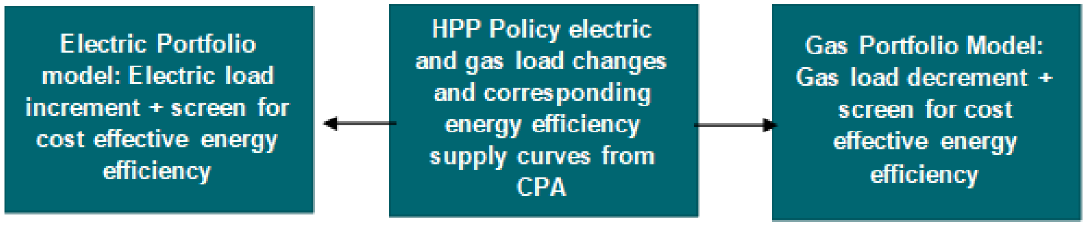
- The HHP policy adds to the electric peak demand from the non-space heating residential end uses that are electrified.
- The HHP policy adds electric peak demand from 30 percent of the industrial load assumed electrified plus 70 percent of the commercial load assumed to be electrified in the Conservation Potential Assessment (CPA).

➔ See Appendix C: Conservation Potential Assessment for more information.

Although the peak demand picture is mixed, keeps significant gas peaks demand, and adds some electric peak demand, the energy impacts in this scenario are different. The gas energy use declines significantly, and the electric energy load build is significant.

The analytical process for the HHP policy scenario is simpler than the HHP market since we assume an end-of-life replacement without regard to economic considerations. We aim to capture the total cost impact on the system for such an approach. In essence, the load is treated as an increment on the electric side and a decrement on the gas side, with the attendant load shape considerations.

Figure E.7: Analytical Process for Evaluating HHP Policy Options in the Gas and Electric System

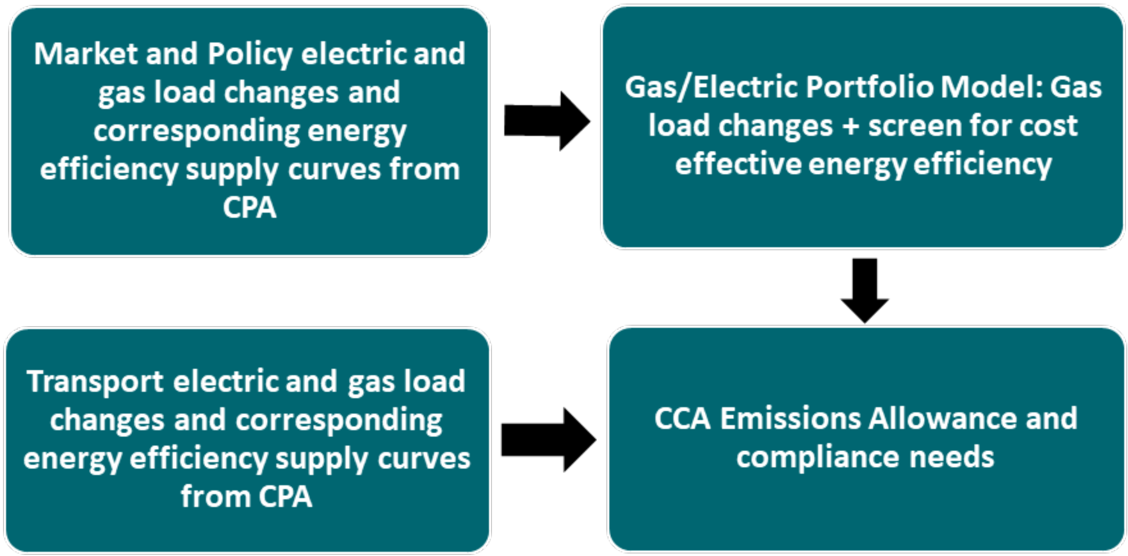


Full Electrification Policy*:* The third scenario assumes that gas end-use equipment is replaced with electric equipment on end-of-life, akin to a policy restricting gas appliance replacements with gas-using equipment. This assumes that residential space heating gas furnaces are replaced with a standard code-compliant electric heat pump. Like most standard heat pumps, such heat pumps switch to electric resistance heat, often known as auxiliary heat, when outside temperatures dip below 30-35°F. There are no cold weather heat pumps in this initial replacement, but there are more efficient heat pump enhancements in the energy efficiency supply curve that accompanies this load reduction/build option. The utility would incentivize the placement of a more efficient heat pump, just as it does with all the other end-use measures. Like the HHP policy scenario, the electric demand increment and the gas load decrements are available simultaneously, as the loads are driven not by economics but by policy. The analytical process is like the one for the HHP policy. See Figure E.7.

We accompanied all three electrification scenarios with a supply curve for the small transport customers whose emissions are under 25,000 tons per year on average from 2015–2019. Transport customers are not gas sales customers and follow a separate analytical process. Since the transport customers' obligation for PSE is only carbon allowances, we could use the allowances to purchase energy efficiency offsets that would reduce emissions. The amount of energy efficiency available at the CCA allowance prices is economically screened in the CPA, and a final economic potential supply curve is provided in the CPA. We input this into the emissions compliance calculations to determine the net allowance needed.

➔ See Appendix C: Conservation Potential Assessment for more details.

Figure E.8: Developing the CCA Allowance Need



6. Resource Alternatives Costs

Table E.10 summarizes resource costs and modeling assumptions for the pipeline alternatives considered in the 2023 Gas Utility IRP, and Table E.11 summarizes resource costs and modeling assumptions for storage alternatives.

Table E.10: Renewal Pipeline Segment Costs

Alternative	From/To	Capacity Demand ($/Dth/Day)	Variable Commodity ($/Dth)	Fuel Use (%)	Earliest Available	Comments
NWP TF-1	Sumas to PSE	0.49	0.09	1.6	Nov. 2024	Contracts aggregated and offered in Nov. 2024, Nov. 2028, and Nov. 2030
NWP TF-1	Stanfield to PSE	0.49	0.09	1.6	Nov. 2024	Contracts aggregated and offered in Nov. 2024 and Nov. 2028
NWP TF-1	Starr Road to PSE	0.49	0.09	1.6	Nov. 2034	-
NWP TF-1	Plymouth to PSE	0.15	0.09	1.6	Apr. 2023	Maximum 15 MDth/d, available from 3rd Parties effective Apr. 2023 associated with Plymouth LNG contract

Note: The Capacity Demand Charge is an average rate over the study period

Table E.11: Resource Costs for Needle Peaking Alternatives

Alternative	Storage Capacity (MDth)	Maximum Withdrawal Capacity (MDth/day)	Days of Full Withdrawal (days)	Capacity Demand Charge ($/Dth/day)	Earliest Available	Comments
Plymouth LNG	241.7	15	16	0.0474	Apr. 2023	Existing plant — requires LT firm NWP capacity
Swarr	90	30	3	0.107	2027	Existing plant requiring upgrades — on-system, no pipeline required

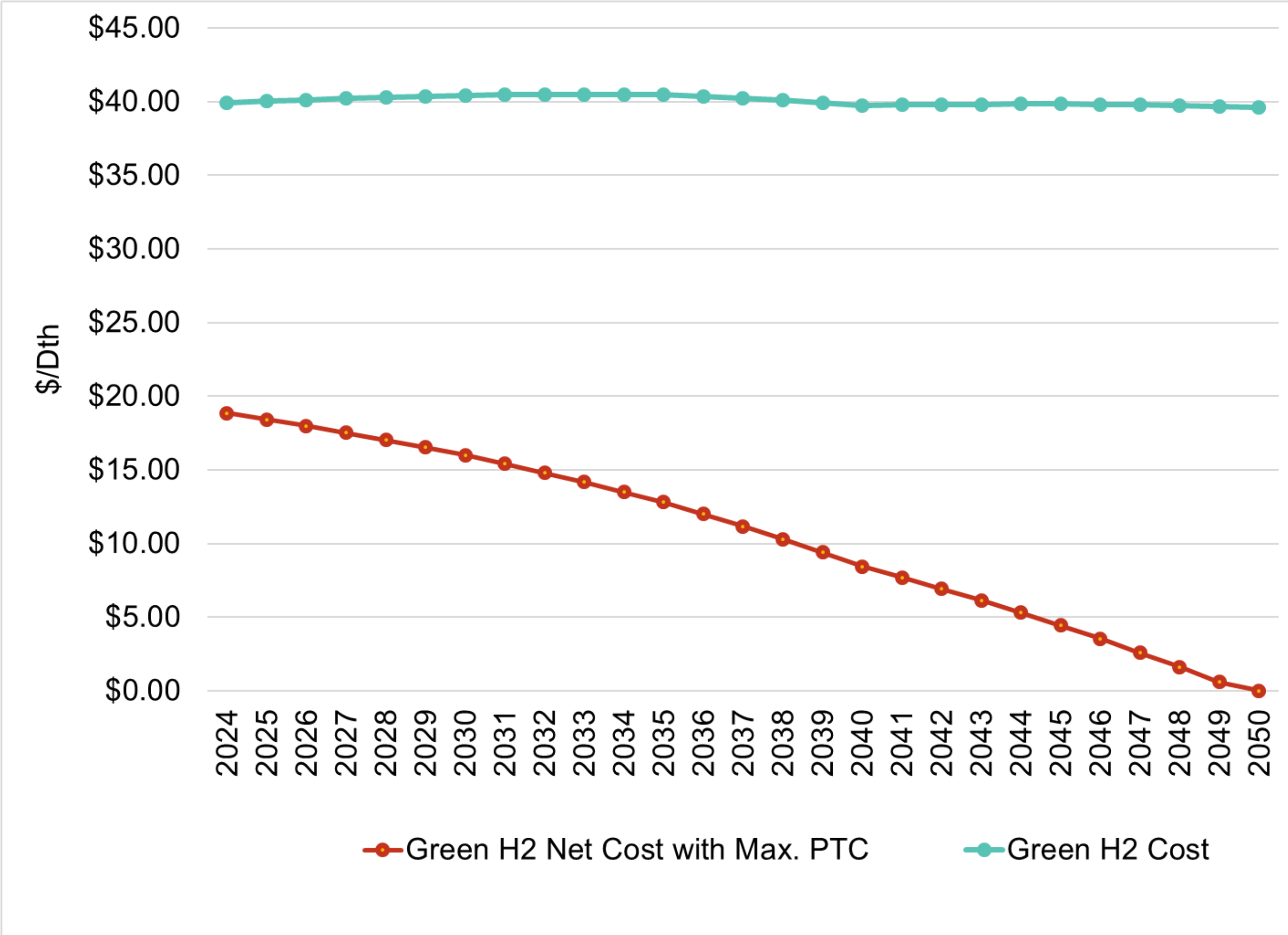
6.1. Green Hydrogen Costs

The federal government recently introduced several powerful incentives to spur green hydrogen development, scalability, and adoption. In late 2021, the Bipartisan Infrastructure Law contained funding for regional hubs nationwide that demonstrate how hydrogen suppliers and end-users can be connected at an industrial scale, laying the groundwork for future commercial opportunities. More recently, the Inflation Reduction Act (IRA) contained production tax credits that incentivize using green power and unionized labor to create green hydrogen. If certain thresholds for power and labor are met, a $3 per kg production tax credit is available, which is approximately a 75 percent reduction compared to the non-PTO commodity cost. Other efforts, including the Department of Energy's Hydrogen Earth Shot, are designed to lower the non-subsidized cost of hydrogen to $1 per kg in one decade.

When comparing hydrogen to natural gas, a baseline of $8 per MMBtu of natural gas is roughly equivalent to $1 per kg of hydrogen. In other words, for the same energy content, a hydrogen supplier contract of $1 per kg would equate to purchasing natural gas at $8 per MMBtu, or 1,000,000 cu ft. Before the passage of the IRA, most cost curves showed a 2020 price point of $4 to $5 for hydrogen, with a relatively stable high price due to the lack of adoption and inability to reach economies of scale. The recent passage of the CCA effectively increases the price of natural gas over time. In conjunction with the IRA subsidies, hydrogen became cheaper than natural gas in the early 2030s. As the region passes through this window, demand will likely increase due to the lower fuel cost, Environmental, Social, and Governance (ESG) commitments, and regulatory mandates at the federal and state levels.

We based the price forecast in Figure E.9 on a dedicated renewable solar electricity source and the price forecast after applying the IRA incentive at $3 per kg of green hydrogen.

Figure E.9: Cost Curve for Washington-based Green Hydrogen Using an Electrolyzer



6.2. Renewable Natural Gas Costs

Table E.12 shows the levelized cost for the various RNG supply options modeled in the gas analysis.

Table E.12: Levelized Cost of RNG

Alternative	RNG Contract	Source	Receipt Point	Max. MDTh/yr	Levelized Cost $/Dth	Year Offered
9	RNG-physical N-1	PNW	Sumas	1,600	20.93	2024
10	RNG-physical N-2	PNW	Sumas	1,388	19.53	2025
11	RNG Attribute-1	N. America	Sumas	3,000	20.77	2024
12	RNG Attribute-2	N. America	Sumas	1,000	21.71	2025
13	RNG Attribute-3	PNW	Stanfield	340	20.25	2024
14	RNG Attribute-4	N. America	Sumas	8,000	19.01	Annual
15	RNG-physical O-1	PNW	On-system	70	19.14	2024

GAS ANALYTICAL METHODOLOGY & RESULTS

APPENDIX F

PUGET SOUND ENERGY

Contents

1. Analytic Methodology

We begin our analysis of Puget Sound Energy's (PSE's) natural gas supply portfolio by comparing 27-year demand forecasts with existing long-term resources to estimate resource needs. Once we identify the resource need, we use planning tools, optimization analyses, and input assumptions to determine the lowest-reasonable-cost portfolio of natural gas resources presented in multiple scenarios.

In the natural gas industry, supply planning is done on a daily basis -- not on an hourly basis. When we say **peak temperature**, we mean 13°F on average for the day, not just during one hour.

2. Gas Peak Day Planning Standard

We completed a detailed cost-benefit analysis during the 2005 least cost plan (LCP), the basis for the current planning standard.[1] In this plan, the 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP), we updated the demand forecast to incorporate the effects of climate change on annual heating and cooling degree days and daily average peak temperatures. Although the annual heating degree days decline over the study period of this plan, the peak temperatures, based on extreme temperature occurrences, support a winter design day peak standard of 13°F, consistent with the prior standard.[2] Thus, we used the 13°F peak design standard in this plan.

3. Deterministic Optimization Analysis

We developed two natural gas scenarios for this plan's analysis: The reference and electrification scenarios, as shown in Table F.1. Scenario analysis allows us to understand how different resources perform across various future economic and regulatory conditions. Scenario analysis also clarifies the robustness of a particular resource strategy; it helps determine if a specific strategy is reasonable under a wide range of possible circumstances.

Table F.1: 2023 Gas Utility IRP Analysis Scenarios

Condition	Reference Case[1]	Electrification WA State Energy Strategy (SES)[2]
CCA Constraint Parameter[1]	Price	Follow SES Line
Allowance Price[2]	Mid	Floor
Renewable Fuel Source Location	North America	North America
Heating Load shift	Economic	Force in Electrification Supply Curve
Demand	Mid (F22)	Mid (F22)
Gas Growth?	Yes	Yes
Gas Price	Mid	Mid

Notes:

1. The price constraint allows PSE to purchase allowances to meet Climate Commitment Act (CCA) requirements. The Follow SES Line constraint imposes a physical emissions constraint as the priority before allowance purchases are permitted.

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[1] For a detailed discussion of the peak planning standard see Chapter Nine in the 2021 IRP.

[2] For a more detailed discussion on the climate models and impacts on energy and peak temperatures, see Chapter Five: Demand Forecast.

2. Climate Commitment Act-related analysis used three allowance prices:
   - Ceiling Price — an allowance issued by the Washington State Department of Ecology (Ecology) at a fixed price to limit price increases.
   - Floor Price — the minimum price at which bids are accepted during an auction.
   - Mid-Price — a hybrid pricing scheme; the pre-2030 period based on the forecast from Ecology and post-2030 period leverages are linked to the California Energy Commission 2021 forecast, modeling the future connection between the two carbon markets.
3. We also tested seven sensitivities in the natural gas sales analysis. Sensitivity analysis allows us to isolate the effect of a single resource, regulation, or condition on the portfolio.

Table F.2: 2023 Gas Utility IRP Natural Gas Portfolio 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

4. Gas Portfolio Model

We used a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and natural gas resource acquisition. The current GPM is SENDOUT Version 14.3.0 from Hitachi Energy, 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.

Although the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge that this technique provides the model with perfect foresight — 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 impossible in the real world. One way we navigate the uncertainty is to create scenarios and sensitivities which help us understand the impacts on the portfolio when variables change. 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.

4.1. SENDOUT Model

SENDOUT is an integrated toolset for gas resource analysis that models the gas supply network and the portfolio of supply, storage, transportation, and demand-side resources (DSR) needed to meet demand requirements. Table 1.1 shows how we used SENDOUT for natural gas resource analysis. We included loads, existing resources, emission adders, and resource alternatives as inputs in the SENDOUT model, and it produces a least-cost portfolio based on those inputs.

SENDOUT can operate in two modes: For a defined planning period, it can determine the optimal set of resources to minimize costs; or, for a defined portfolio, it can determine the least-cost dispatch to meet demand requirements for that portfolio. SENDOUT solves both problems using a linear program (LP) to determine how a portfolio of resources (energy efficiency, supply, storage, and transport), including associated costs and contractual or physical constraints, should be added and dispatched to meet demand in a least-cost fashion. The LP considers thousands of variables and evaluates tens of thousands of possible solutions to generate a solution. A standard planning-period dispatch considers the capacity level of all resources as given and therefore performs a variable-cost dispatch. A resource-mix dispatch can look at various potential capacity and size resources, including their fixed and variable costs.

Puget Sound Energy's gas portfolio model analysis follows a five-step process:

1. Set up a database with existing resources and demand forecasts.
2. Update the inputs for natural gas prices, carbon adders, and new resource alternatives.
3. Perform a long-run capacity expansion analysis to get a least-cost portfolio for each scenario and sensitivity.
4. Analyze the results.
5. Develop a resource plan.

4.2. SENDOUT Inputs

Natural Gas Prices

For natural gas prices, PSE uses a combination of forward market prices and fundamental forecasts acquired in spring 2020 from the consulting firm Wood Mackenzie. The natural gas price forecast is an input for SENDOUT.

➔ We described natural gas price inputs in Chapter Four: Key Analytical Assumptions.

CO_2 Price Inputs

RCW 80.28.380[3] requires that the natural gas analysis include the cost of greenhouse gases when evaluating the cost-effectiveness of natural gas conservation targets. We added the social cost of greenhouse gas (SCGHG) to the natural gas commodity price to implement this requirement.

➔ We provided detailed inputs in Chapter Four: Key Analytical Assumptions.

Demand-side Resources

SENDOUT provides a comprehensive set of inputs to model a variety of energy efficiency programs. Costs can be modeled at an overall program level or broken down into detailed accounts. We can model the impact of demand-side resources on the load at the same level of detail as demand. SENDOUT can integrate demand- and supply-side resources in the long-run resource mix analysis to determine the most cost-effective size of demand-side resources.

➔ We provided detailed inputs in Appendix C: Conservation Potential Assessment.

Natural Gas Supply

SENDOUT allows a system to get supply from long-term natural gas contracts or short-term spot market purchases. We can model specific physical and contractual constraints such as maximum flow levels and minimum flow percentages daily, monthly, seasonal, or annually. SENDOUT uses standard gas contract costs; we can change the rates monthly or daily.

[3] RCW 80.28.380

Storage

➔ More information on natural gas storage is in Appendix E: Existing Resources and Resource Alternatives.

SENDOUT allows leased or company-owned storage sources to serve the system. Storage input data include the minimum or maximum inventory levels, minimum or maximum injection and withdrawal rates, injection, and withdrawal fuel loss to and from interconnects, and the period of activity (i.e., when the gas is available for injection or withdrawal). There is also the option to define and name volume-dependent injection and withdrawal percentage tables (ratchets), which we can apply to one or more storage sources.

Transportation

SENDOUT provides the means to model transportation segments to define flows, costs, and fuel loss. Flow values include minimum and maximum daily quantities available for sale to gas markets or for release. Costs include standard fixed and variable transportation rates and a per-unit cost generated for released capacity. We can also model seasonal transportation contracts.

➔ More information on natural gas transportation is in Appendix E: Existing Resources and Resource Alternatives.

Demand

SENDOUT allows the user to define multiple demand areas, and it can compute a demand forecast by class based on weather. We segregated the demand input into two components:

1. Base load, which is not weather dependent
2. Heat load, which is weather dependent

We also computed both factors as a function of customer counts. The heat load factor is estimated by dividing the remaining non-base portion of the load by historical monthly average heating degree days (HDD) and monthly forecasted customer counts to derive energy per HDD per customer. The demand is input into SENDOUT monthly and includes the customer forecast, the baseload factors, and the heat load factors computed over the 20-year demand forecast period.

➔ More information on the natural gas demand forecast is in Chapter Five: Demand Forecast.

5. Gas Portfolio Results

The results of the SENDOUT model runs provide a view of the lowest cost portfolios in each scenario and sensitivity. In this section, we provide the results of the portfolio analysis. There are two scenarios in the gas analysis: the reference and electrification scenarios.

➔ More information on the natural gas portfolio results is in Chapter Six: Gas Analysis.

5.1. Scenario One: Reference Scenario

Portfolio additions represent the least cost builds for that scenario or sensitivity.

Figure F.1: Reference Scenario Portfolio Additions

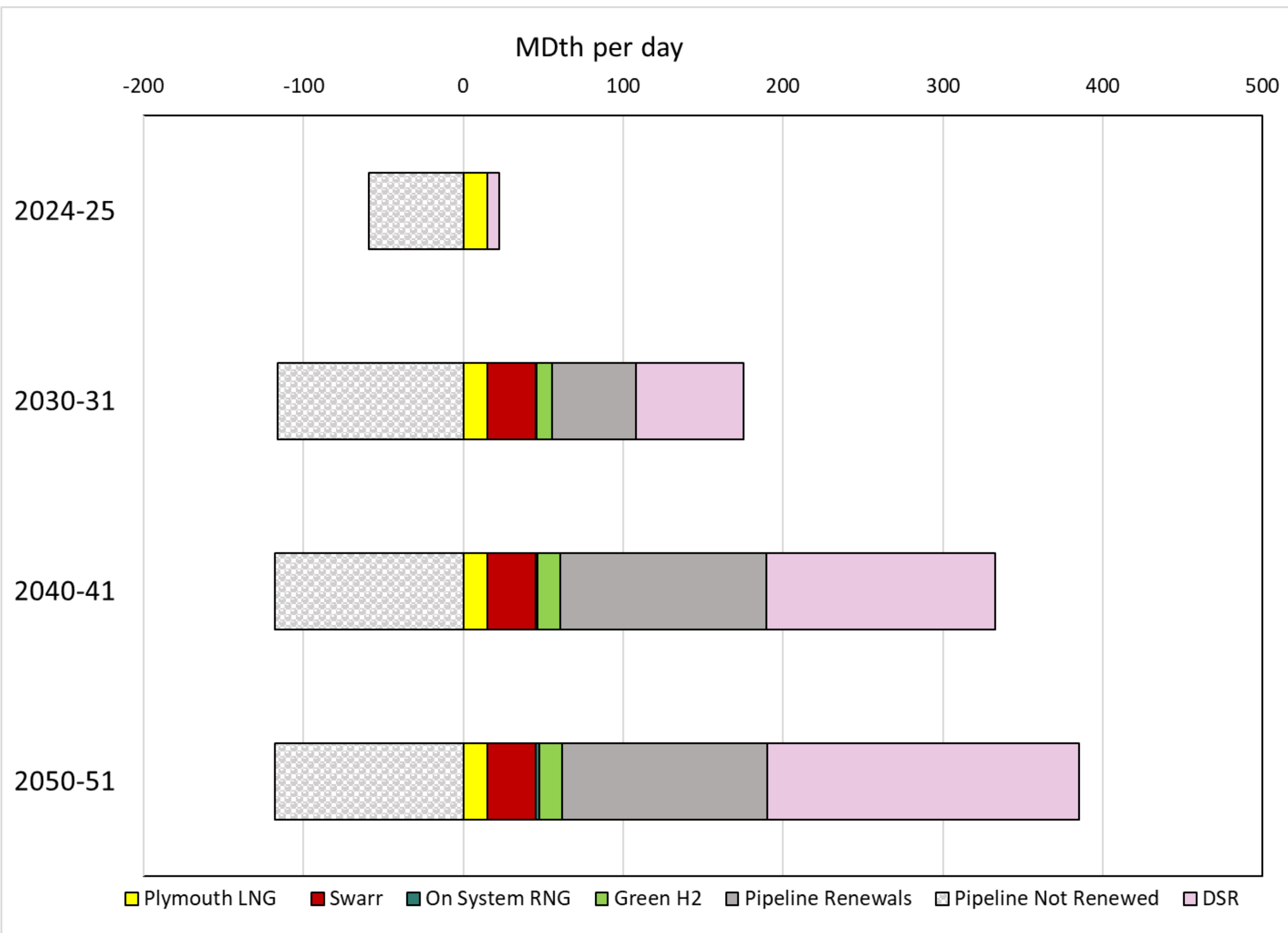
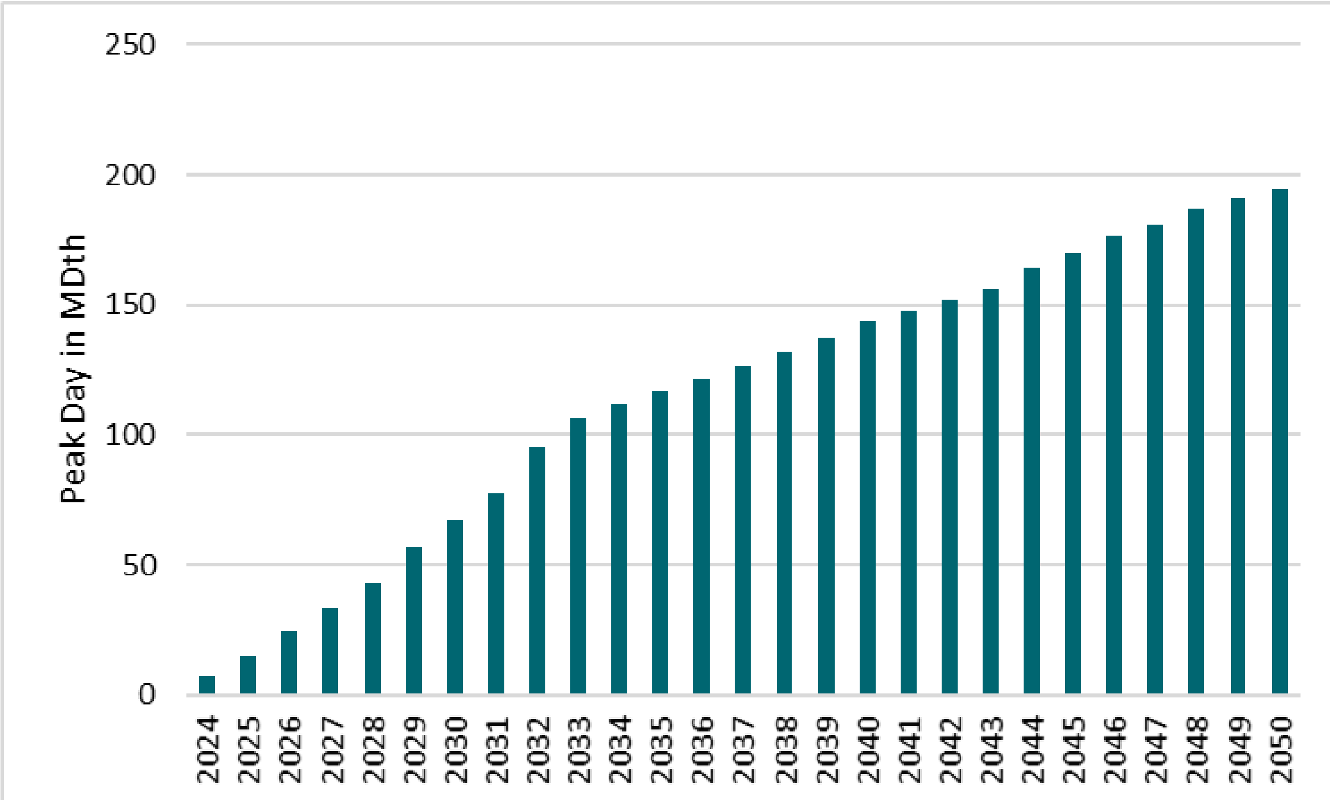
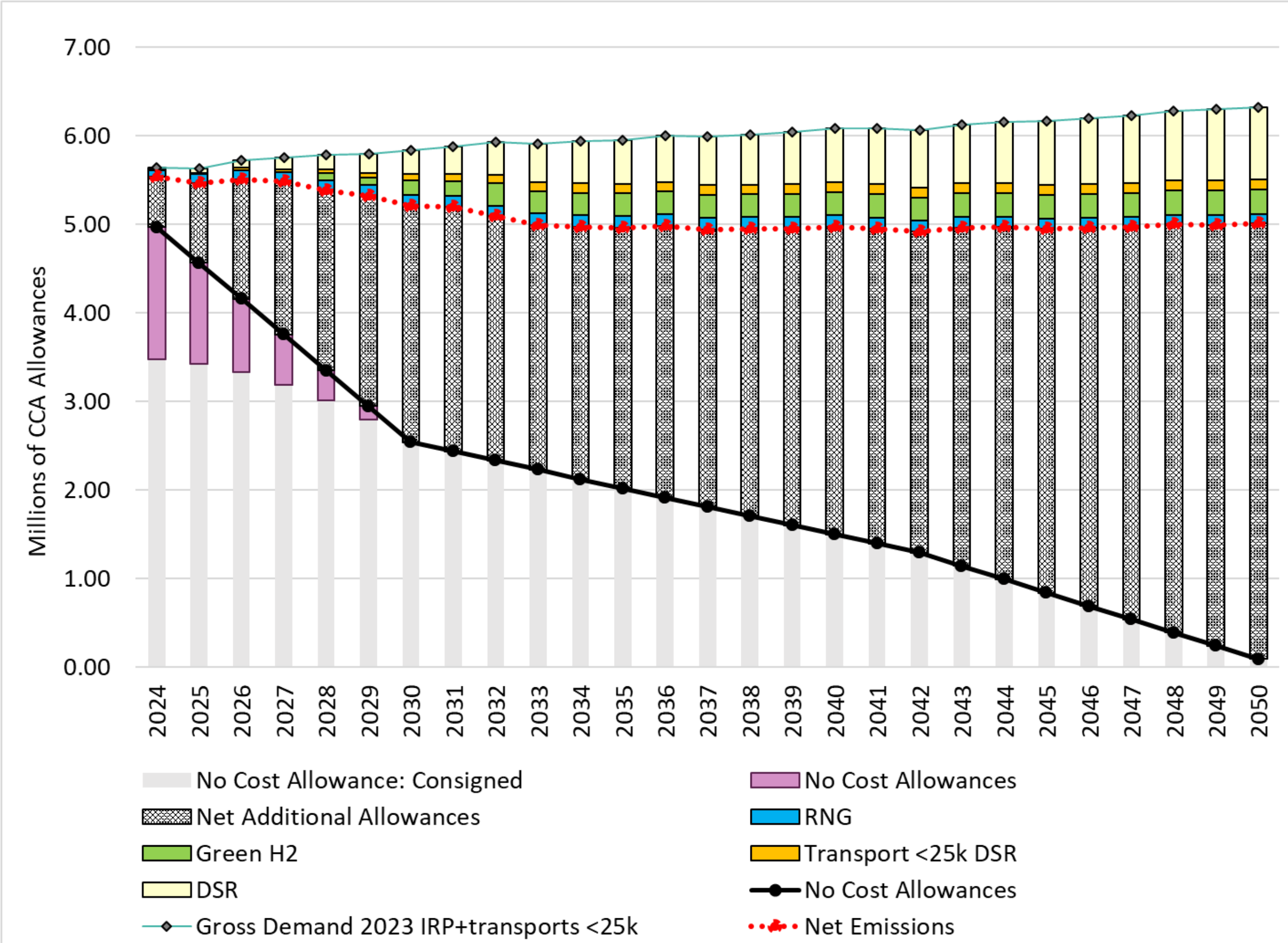


Figure F.2: Reference Scenario — Demand-side Resource Additions



We provided the data for portfolio additions in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least cost portfolio in that scenario or sensitivity.

Figure F.3: Reference Scenario — CCA Emissions



5.2. Scenario Two: Electrification Scenario

Portfolio additions represent the least-cost builds for that scenario or sensitivity.

Figure F.4: Electrification Scenario — Portfolio Additions

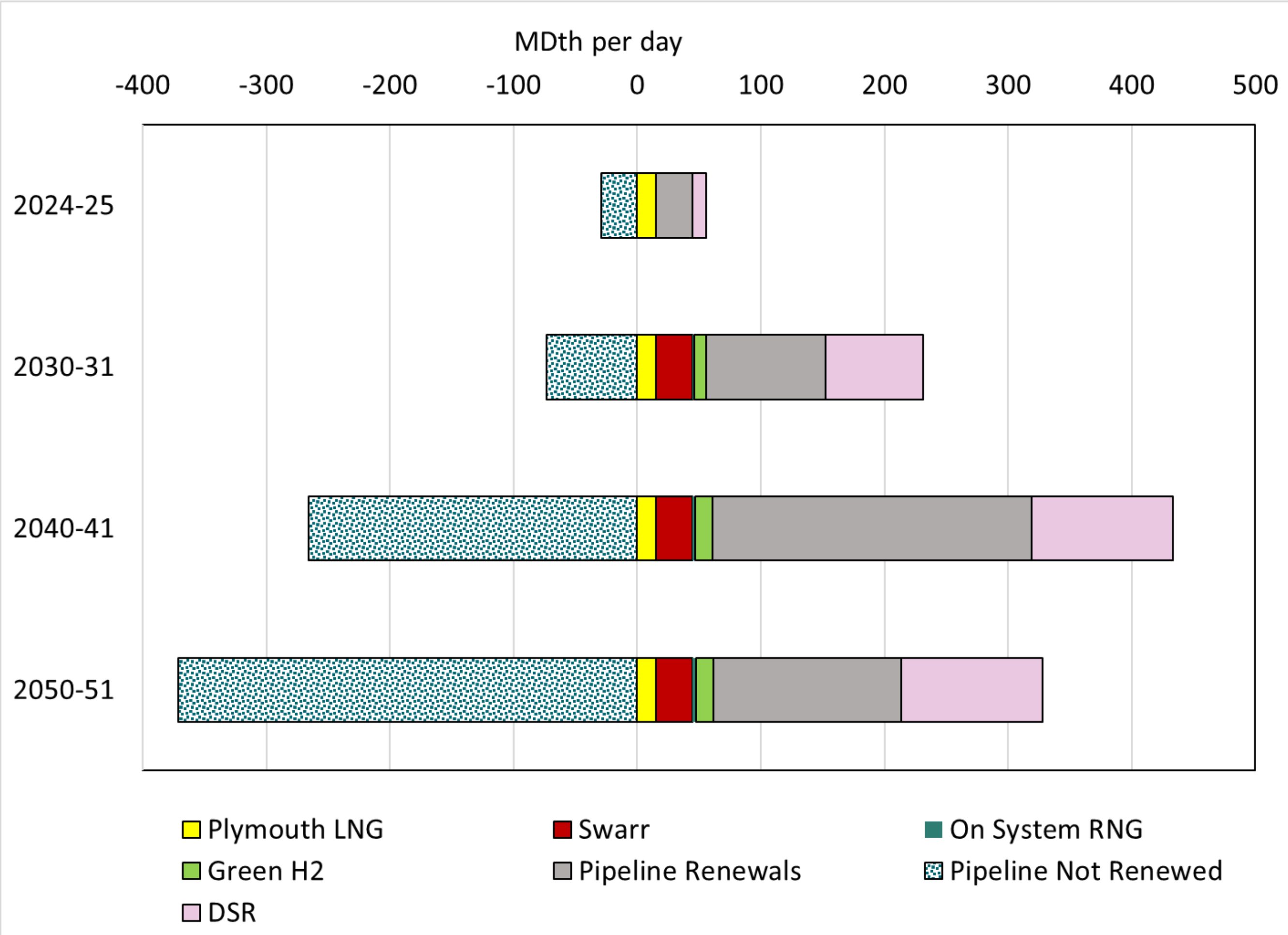
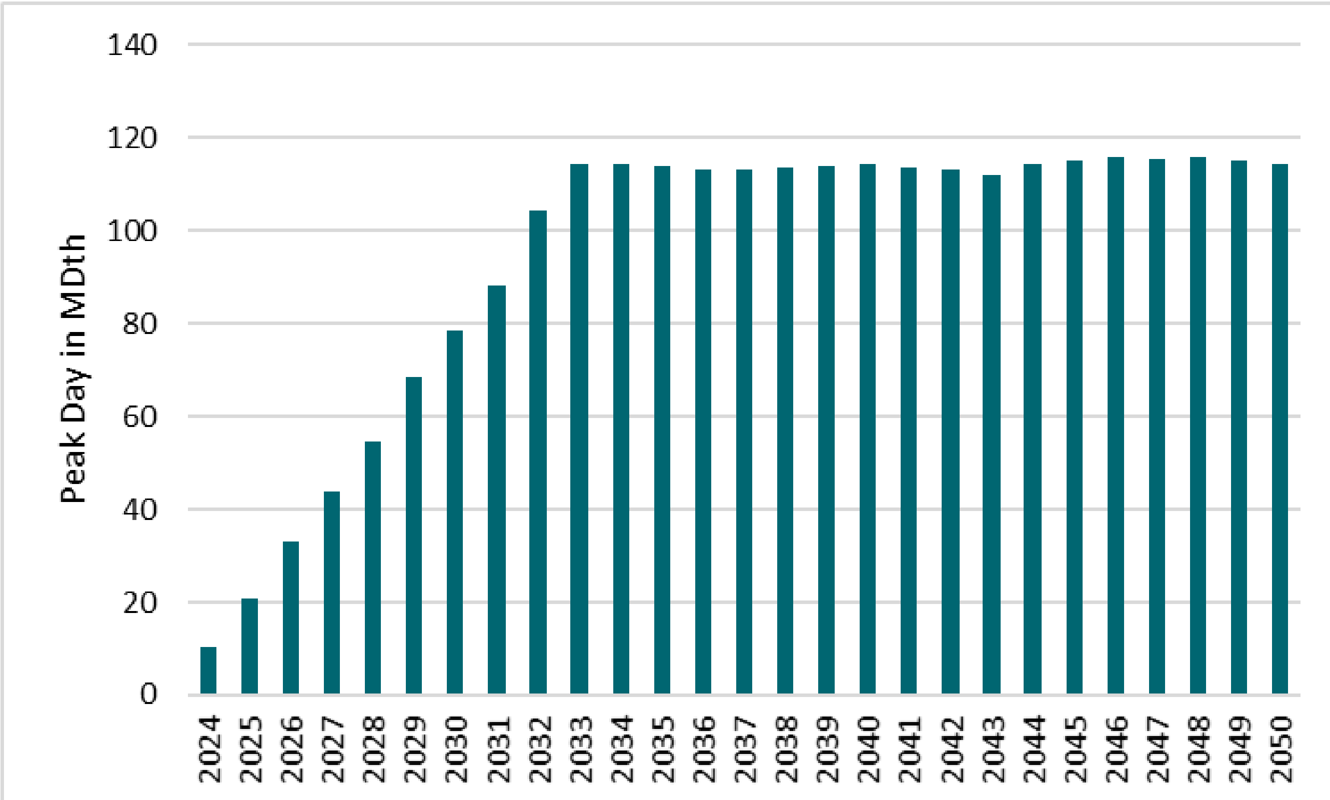
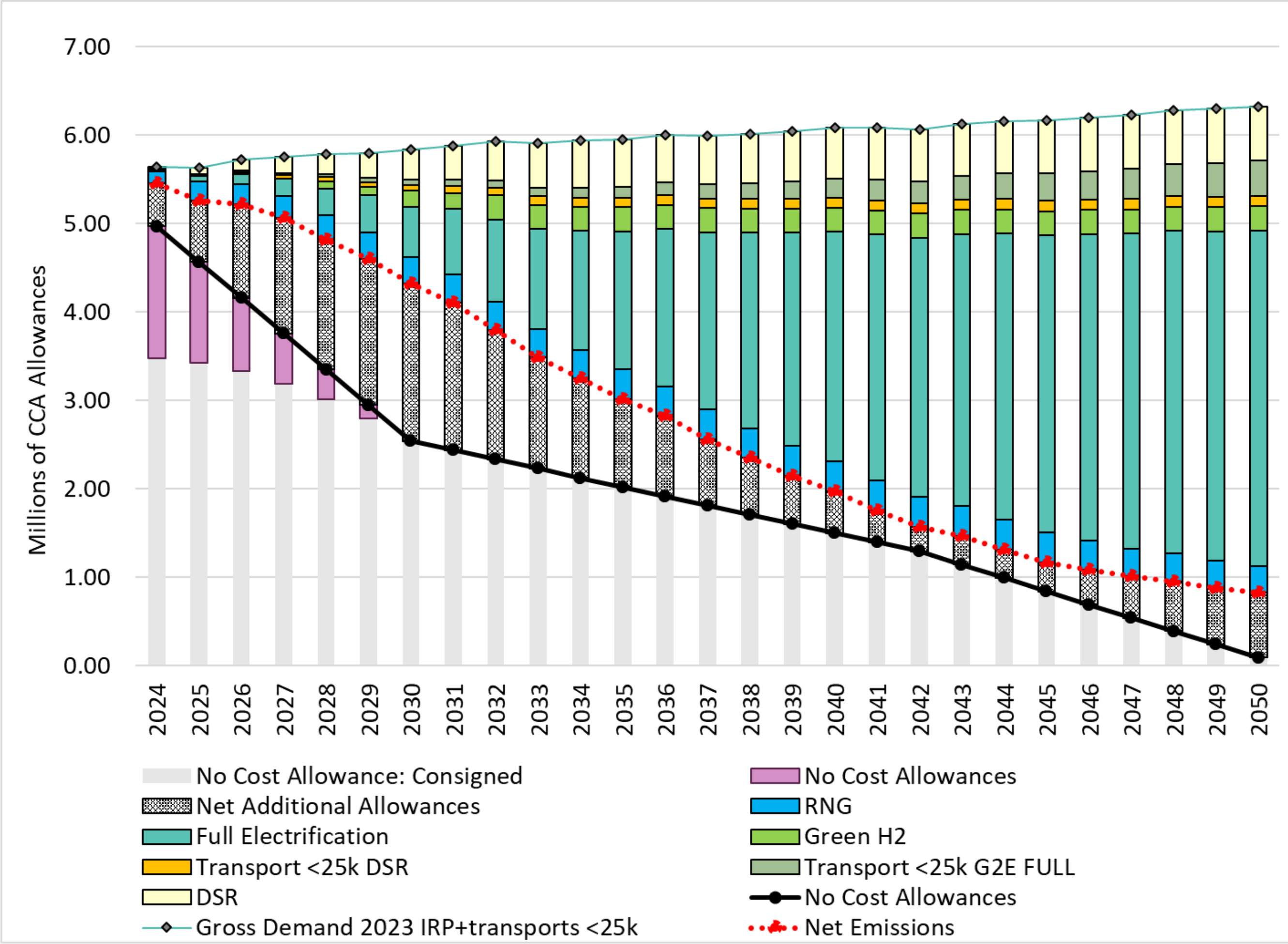


Figure F.5: Electrification Scenario — Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the portfolio emissions profile on the least-cost portfolio in that scenario or sensitivity.

Figure F.6: Electrification Scenario — CCA Emissions



5.3. 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 F.3 and described them in the following sections.

Table F.3: 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	High	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.

Figure F.7: CCA Allowance Price High — Portfolio Additions

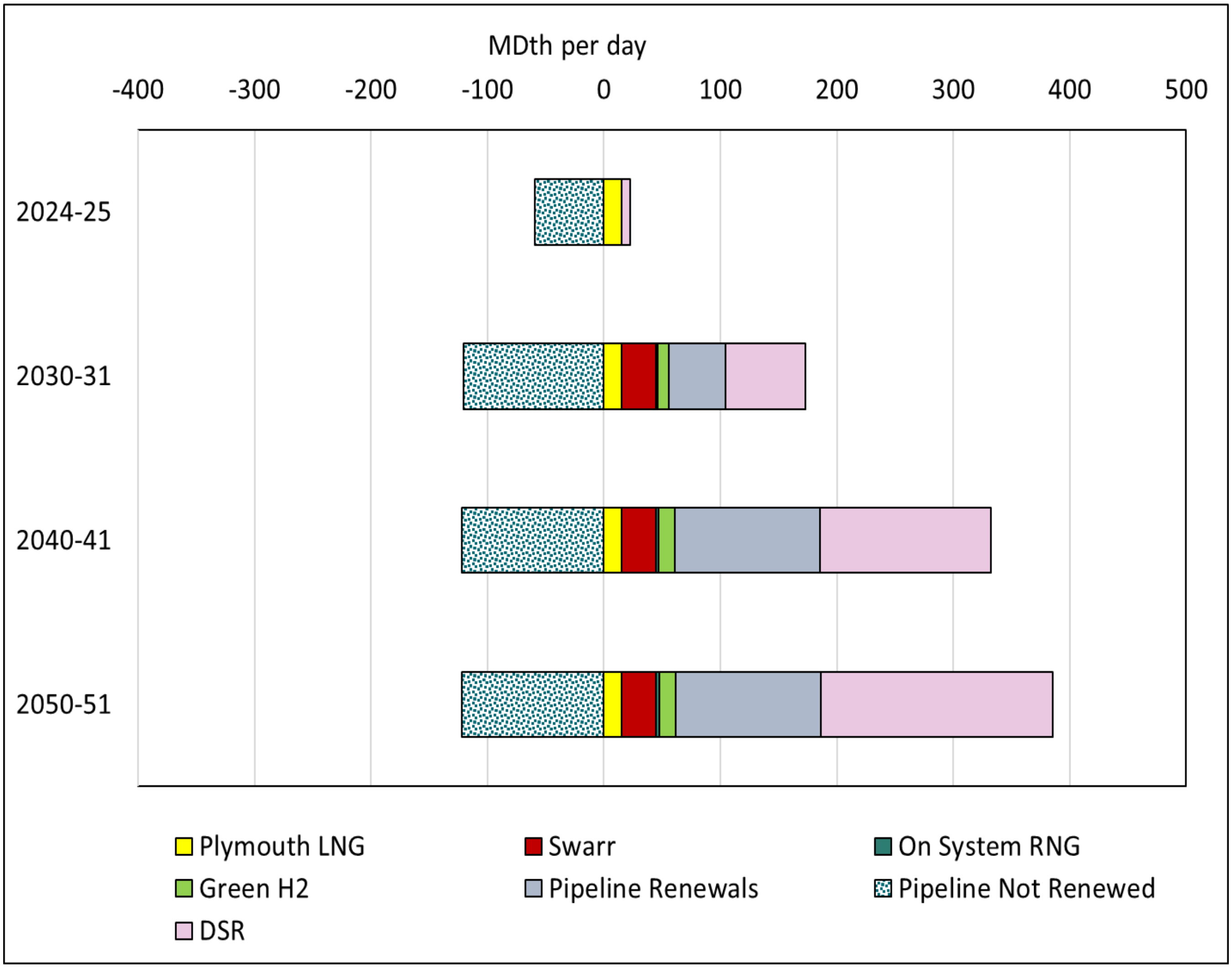
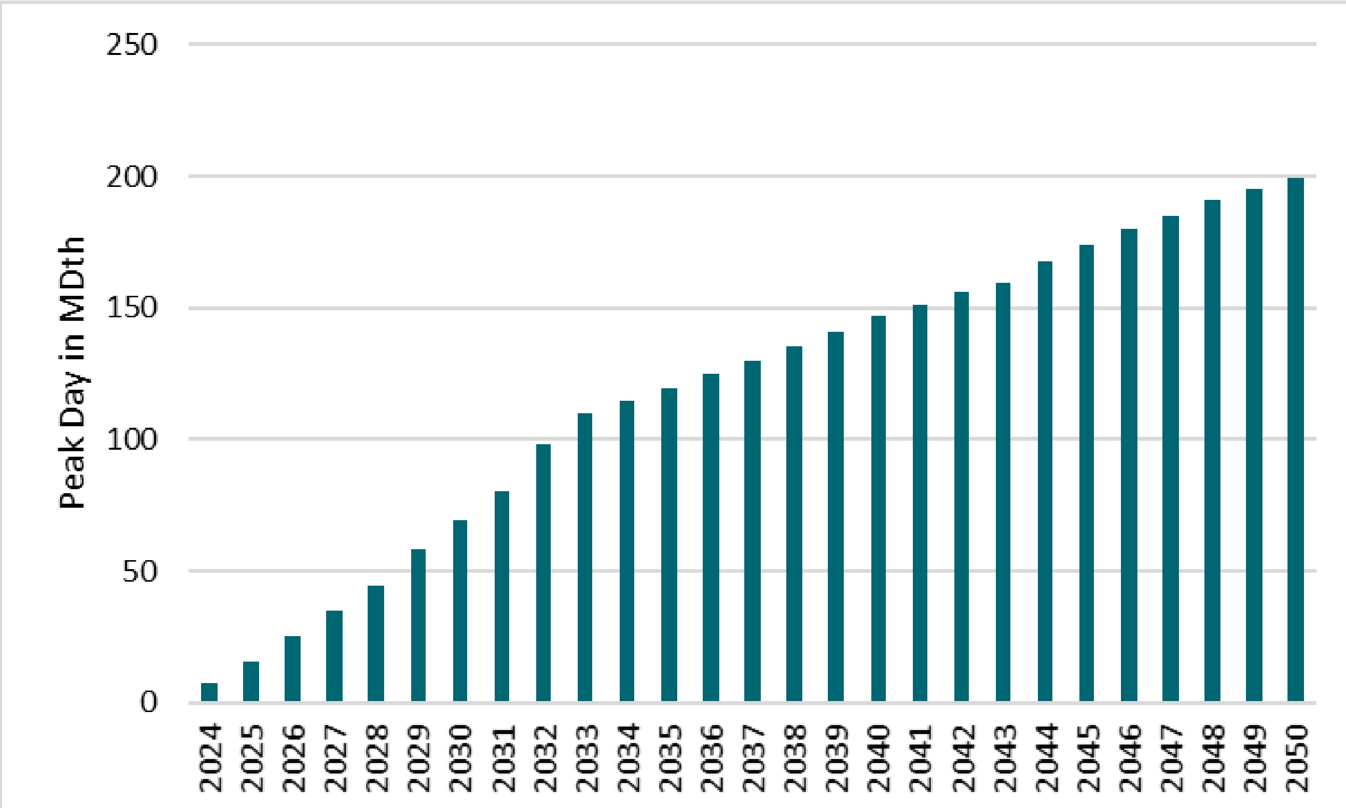
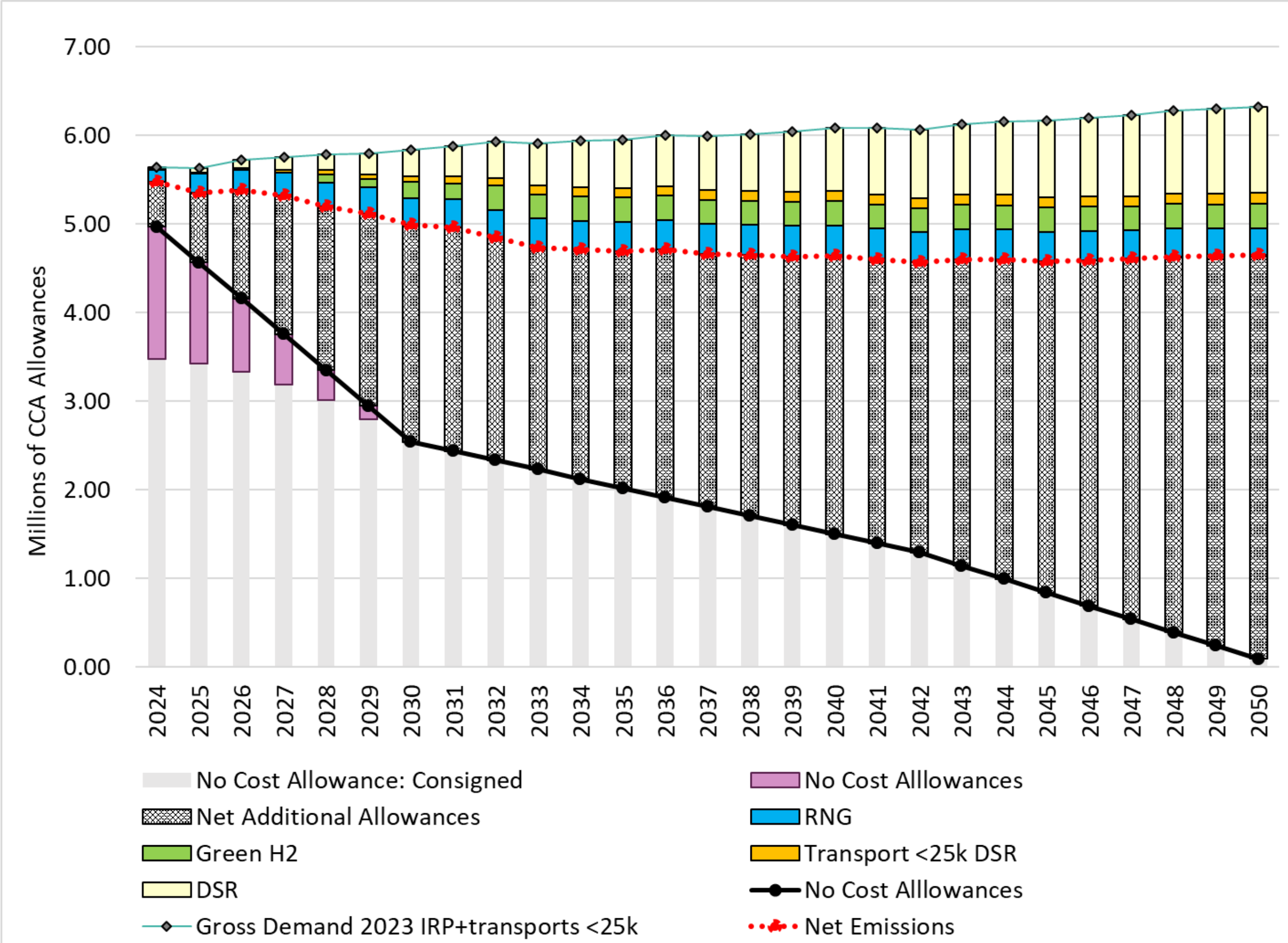


Figure F.8: CCA Allowance Price High Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least- cost portfolio in that scenario or sensitivity.

Figure F.9: CCA Allowance Price High – CCA Emissions



B — CCA Allowance Price Low

This sensitivity tests the impacts of a low floor allowance price.

Figure F.10: CCA Allowance Price Low — Portfolio Additions

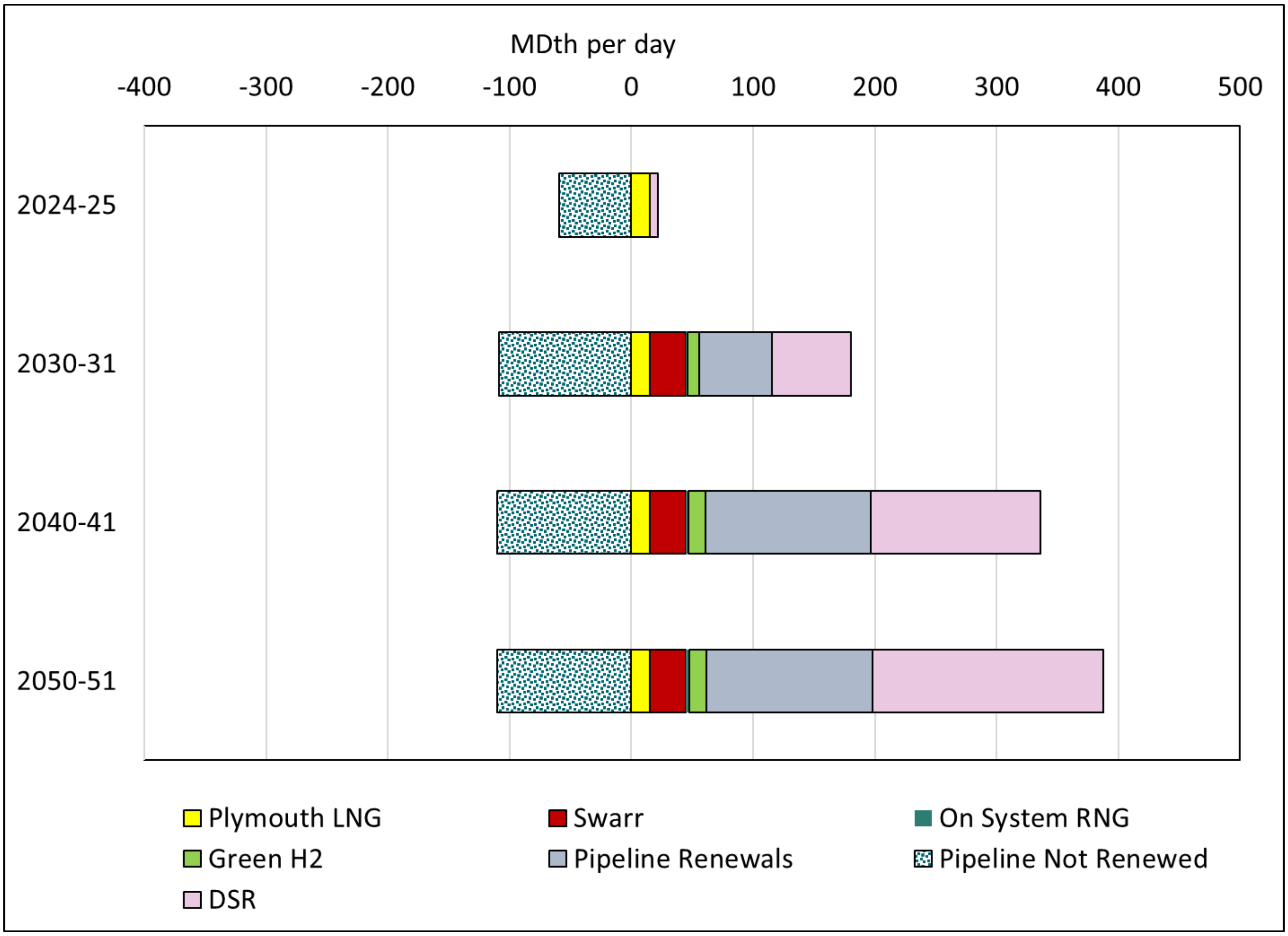
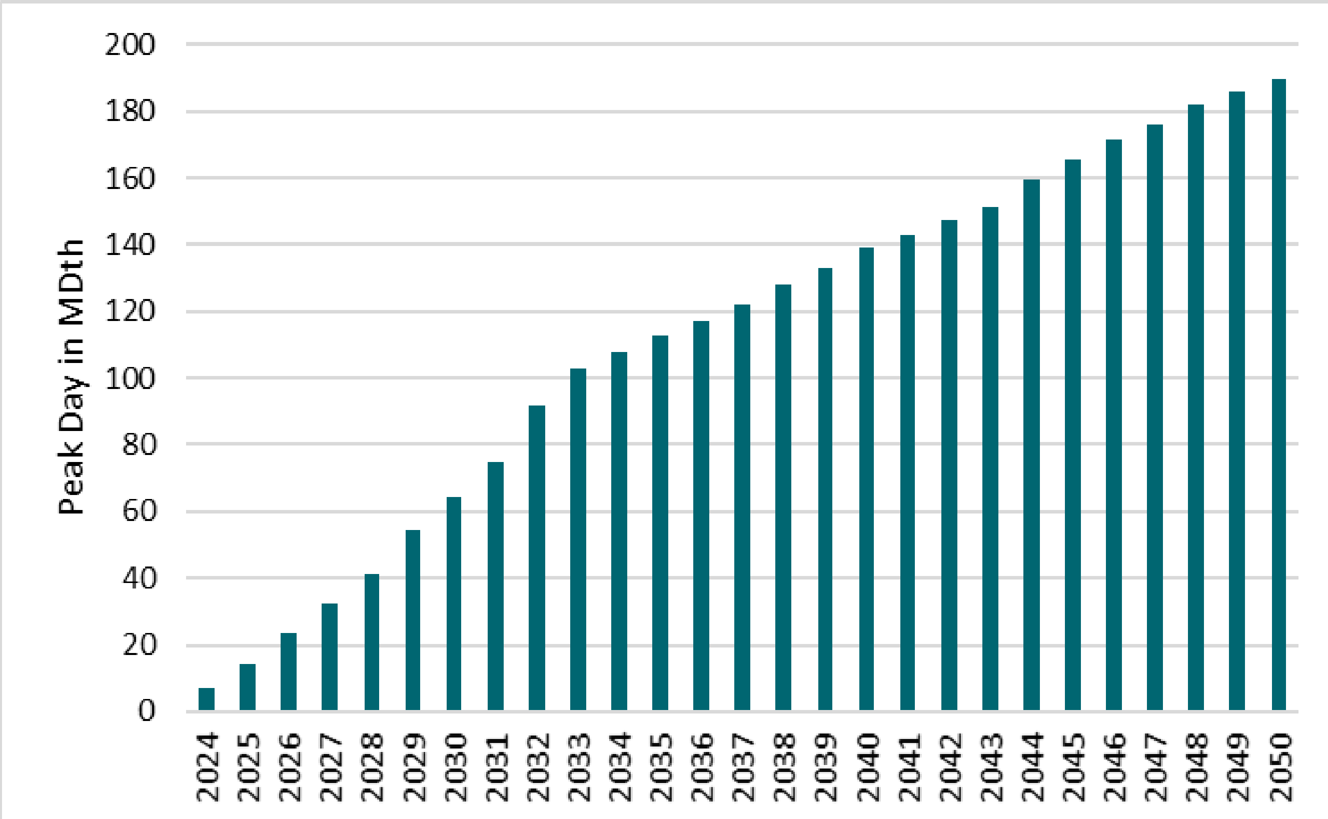
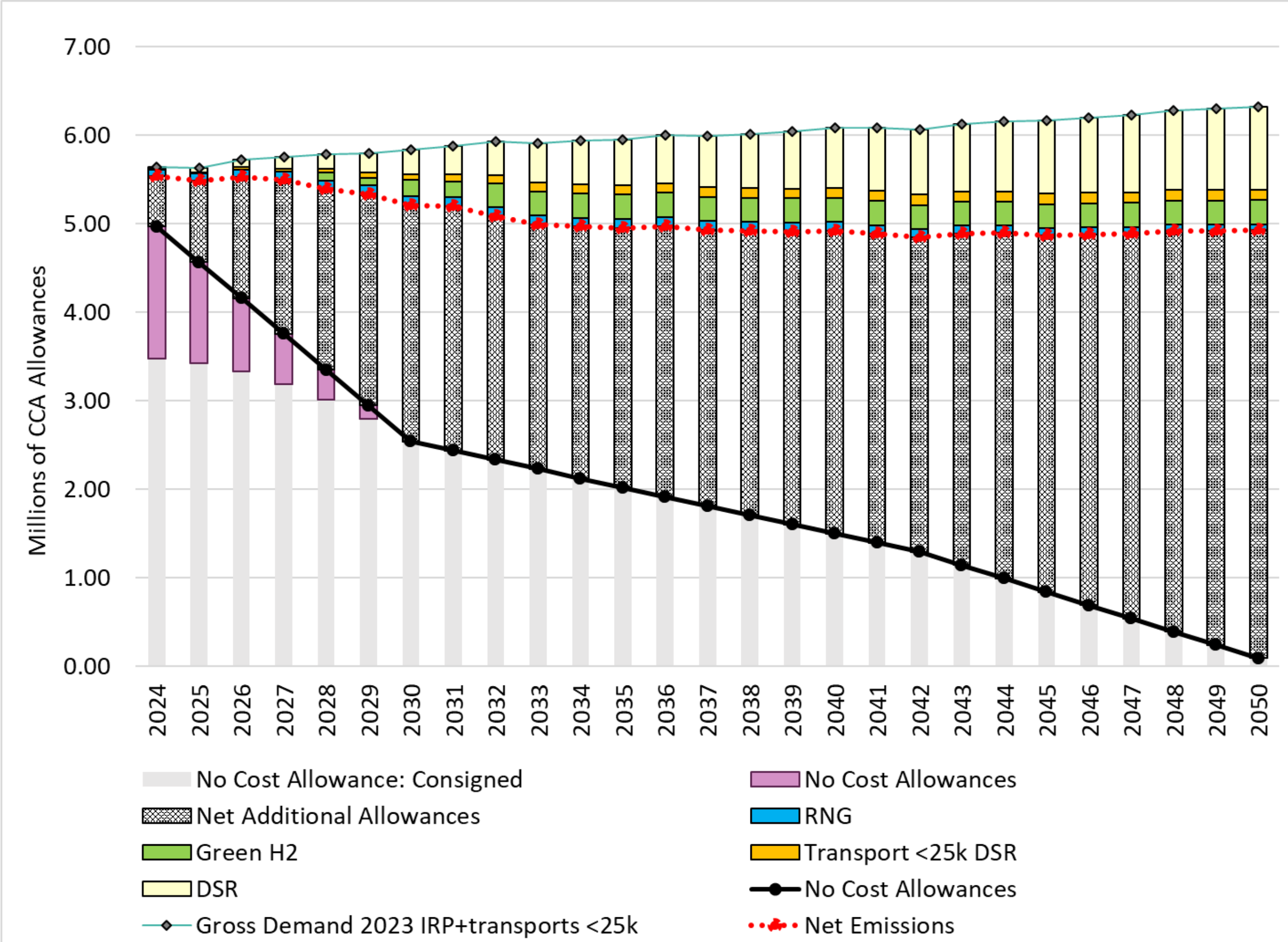


Figure F.11: CCA Allowance Price Low — Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.12: CCA Allowance Price Low — CCA Emissions



C — Limiting Emissions Without Regard to Price

This sensitivity minimizes carbon emissions with the resource options in the gas model before it purchases above the allocated 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.

Figure F.13: Limiting Emissions without Regard to Price — Portfolio Additions

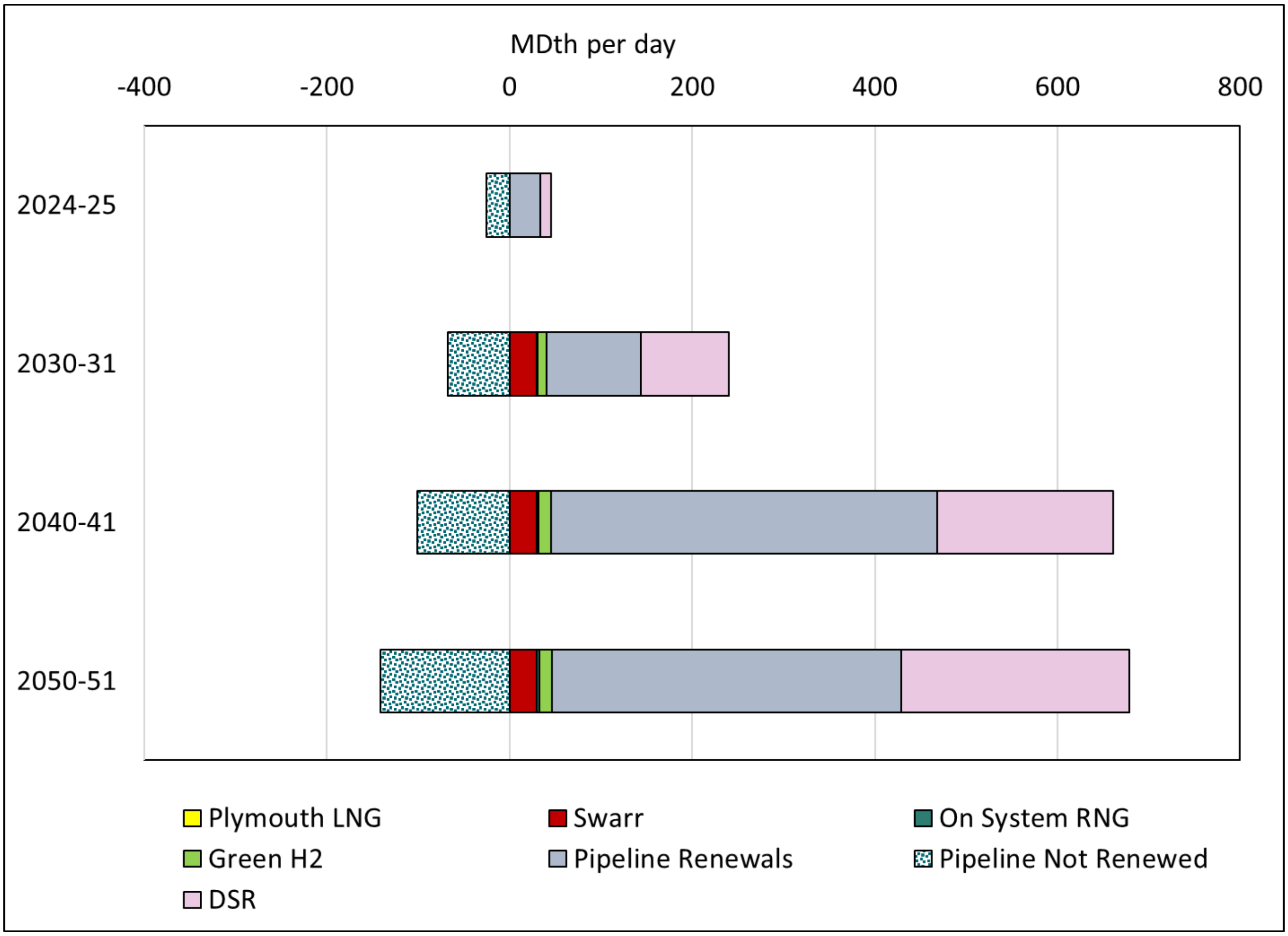
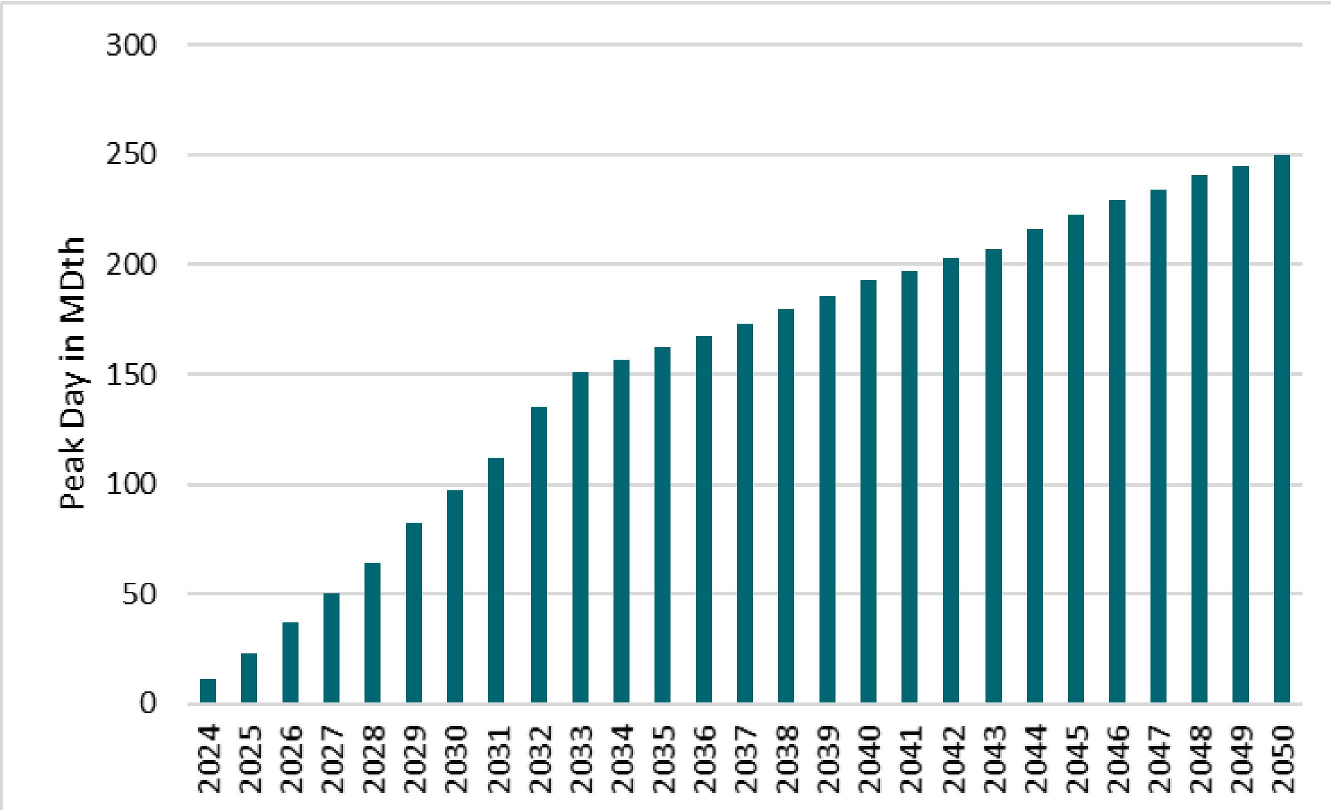
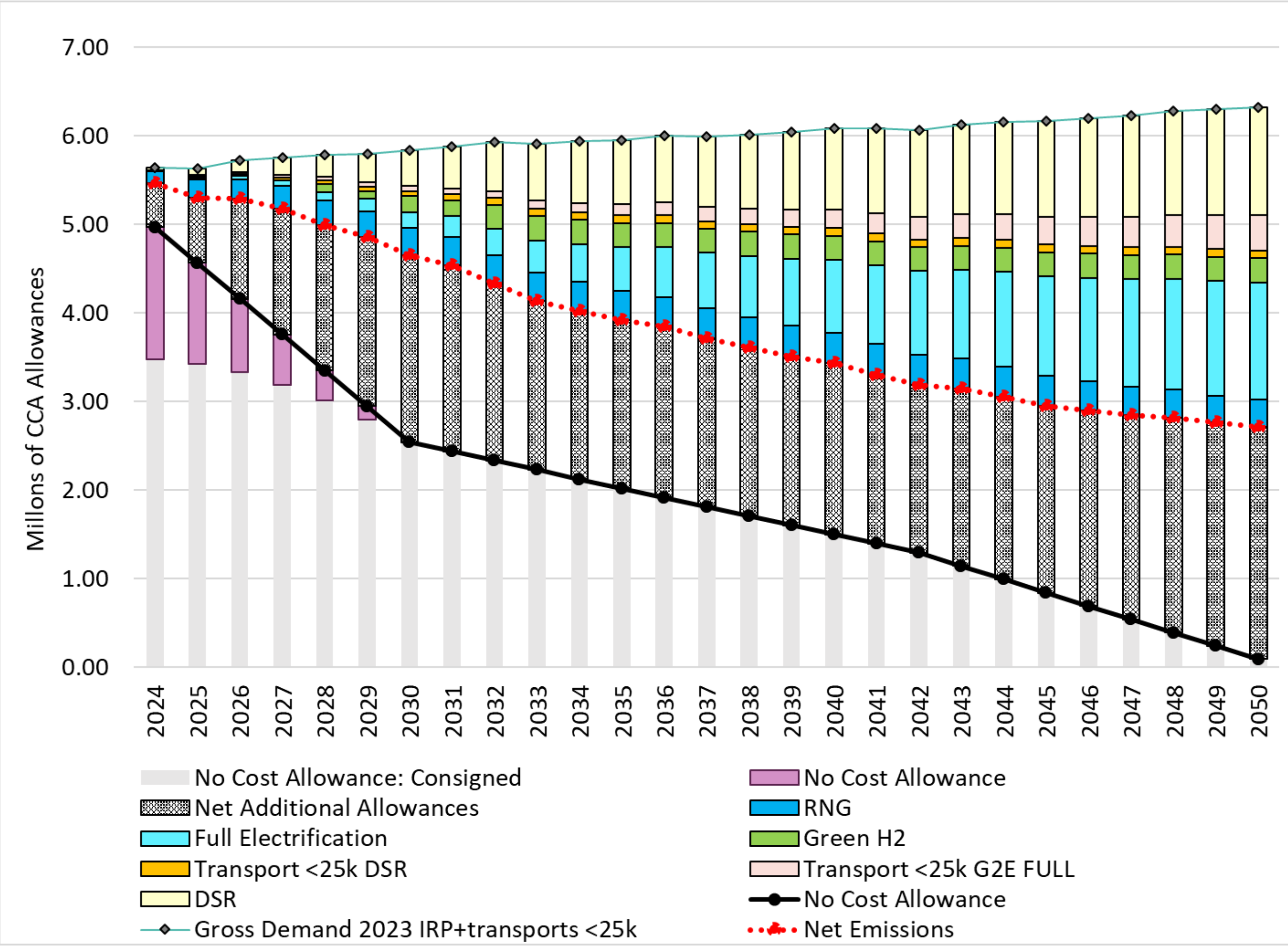


Figure F.14: Limiting Emissions without Regard to Price — Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.15: Limiting Emissions without Regard to Price — CCA Emissions



D — Alternate Fuel Sourcing Not Limited to PNW

This sensitivity model removes the constraint of sourcing alternate renewable fuels from the PNW to include North America; this applies to RNG and green hydrogen.

Figure F.16: Alternate Fuel Sourcing Not Limited to PNW — Portfolio Additions

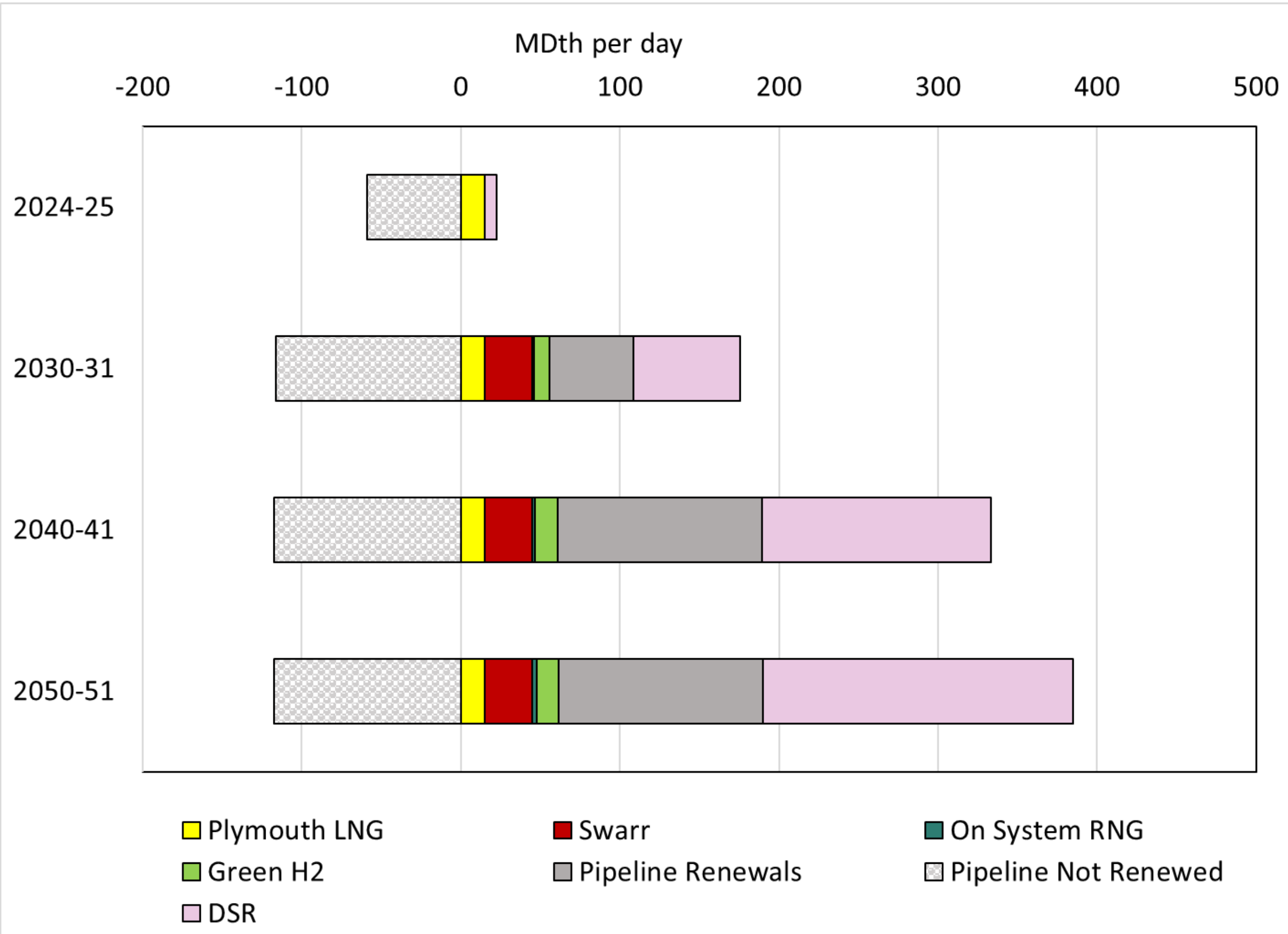
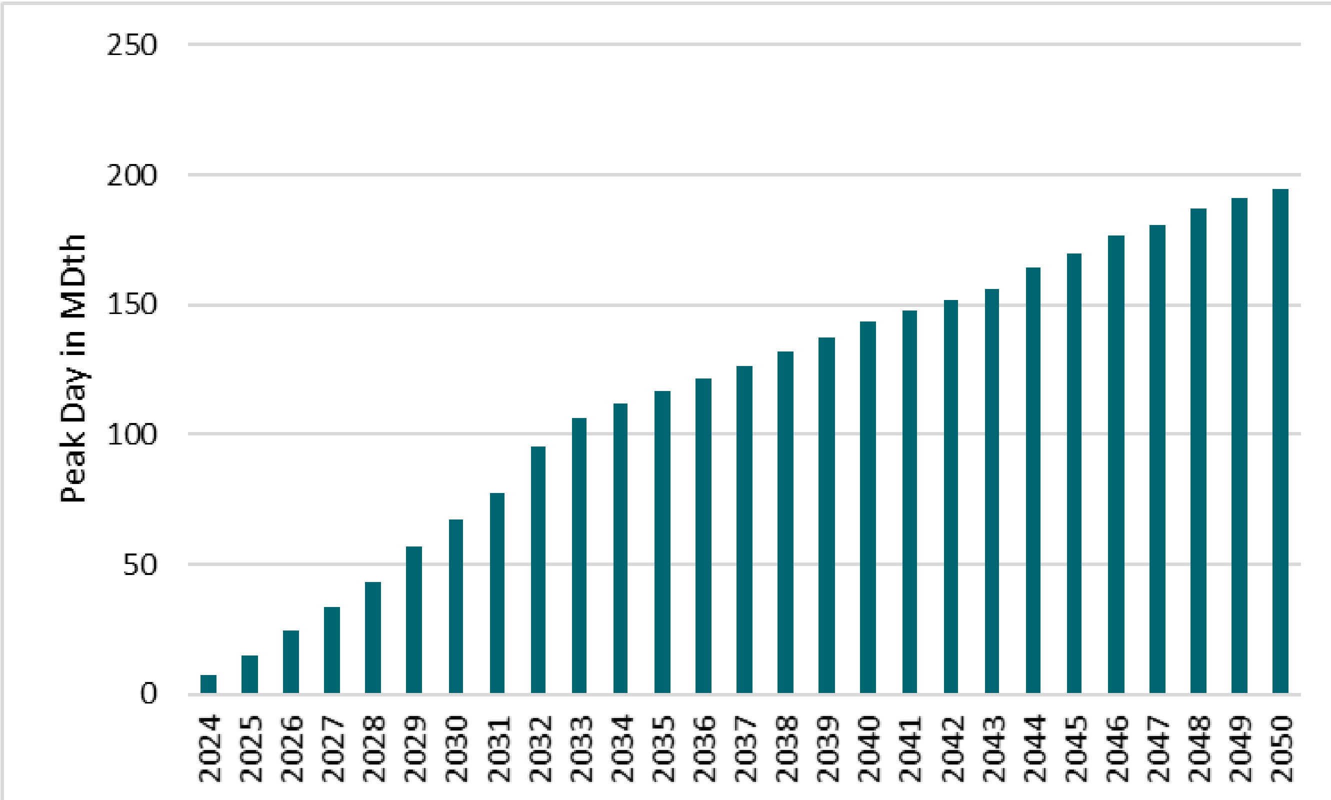
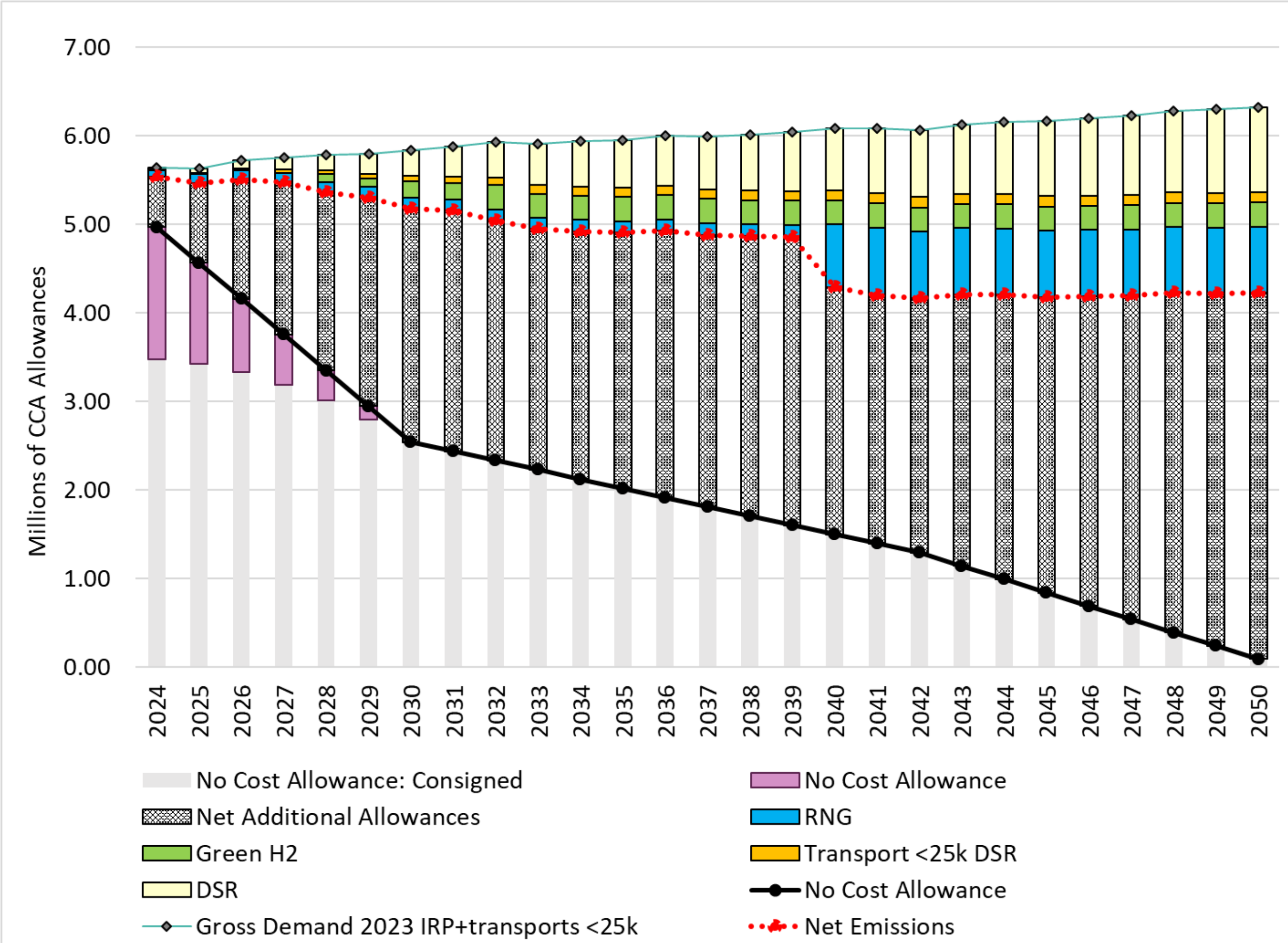


Figure F.17: Alternate Fuel Sourcing Not Limited to PNW — Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.18: Alternate Fuel Sourcing Not Limited to PNW — CCA emissions



E — Hybrid Heat Pump 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 will be electrified.

Figure F.19: Hybrid Heat Pump Adoption Policy Portfolio Additions

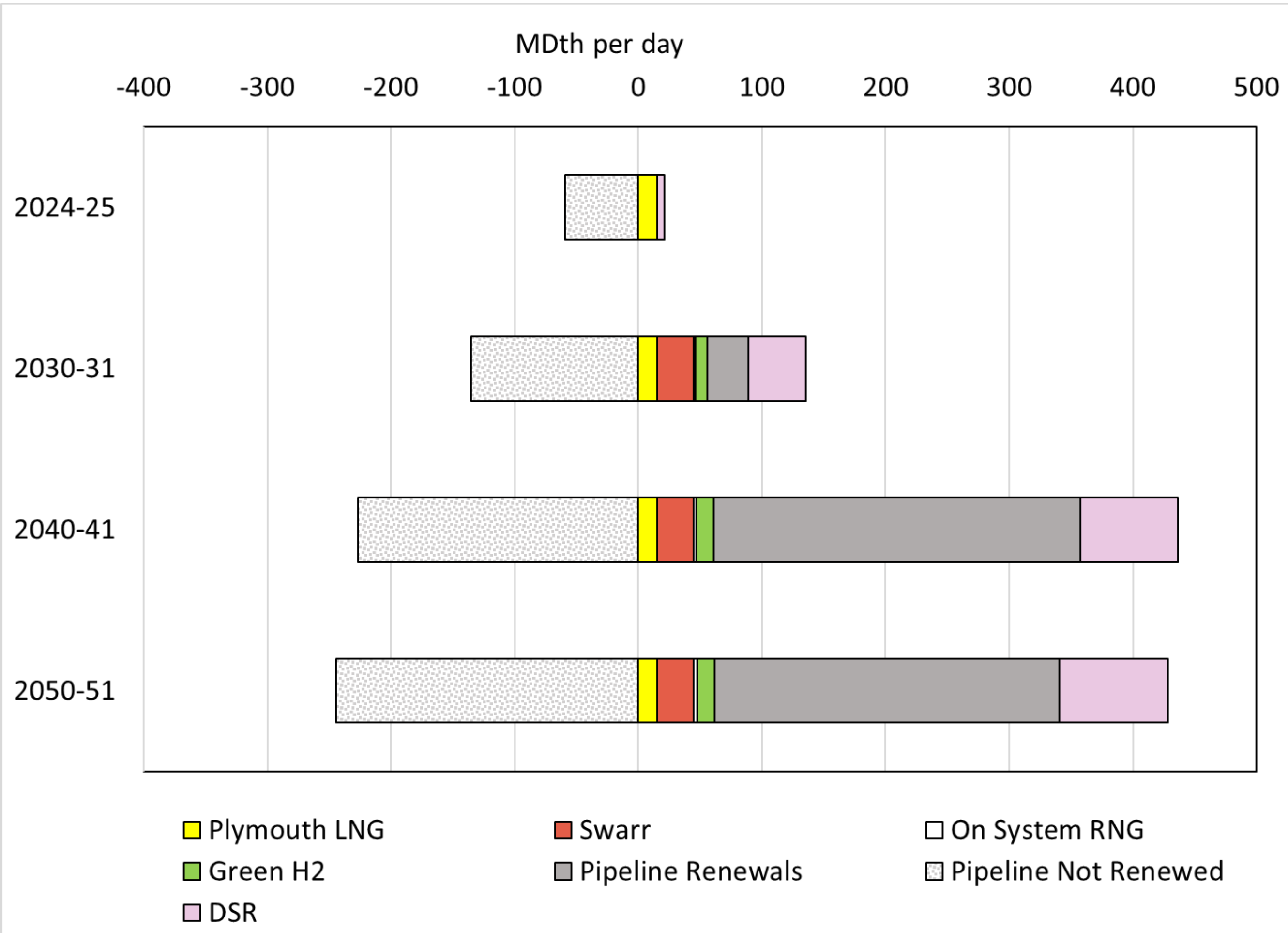
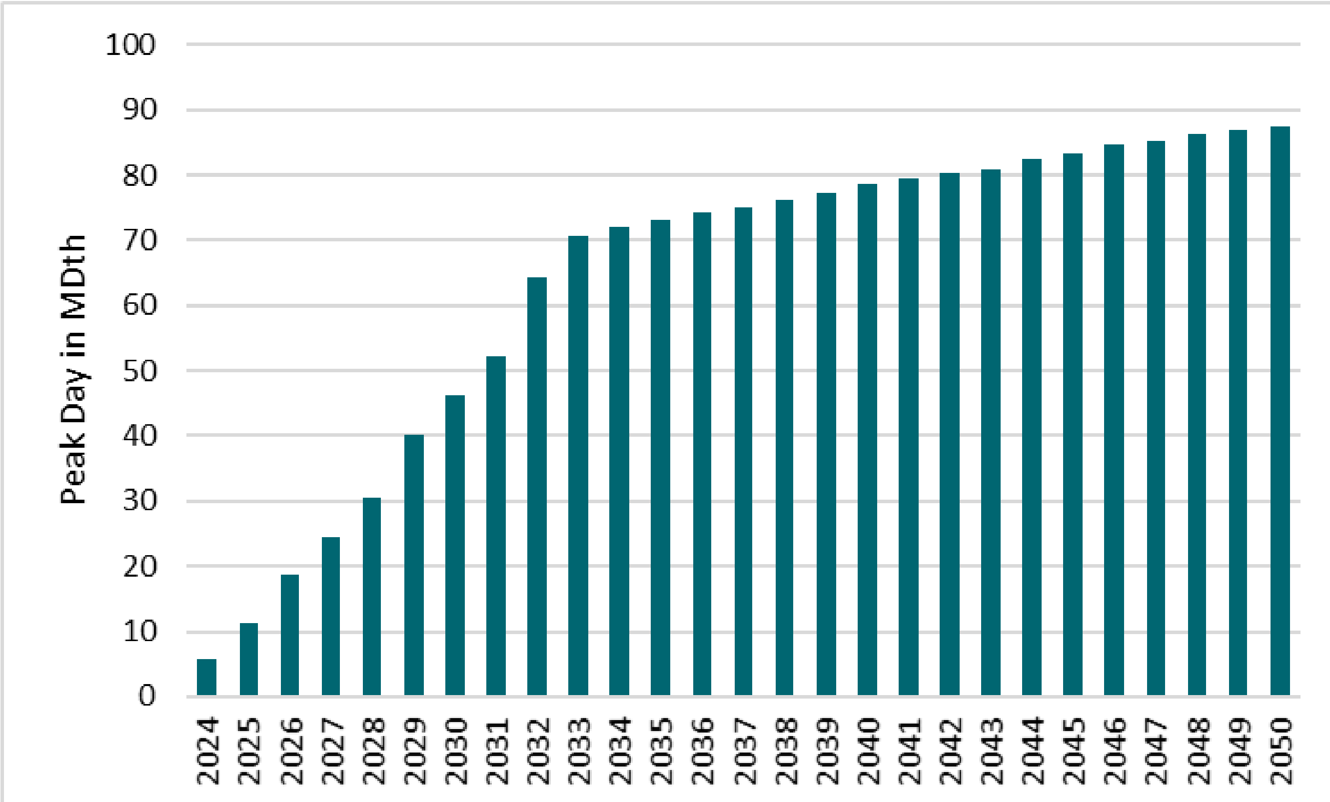
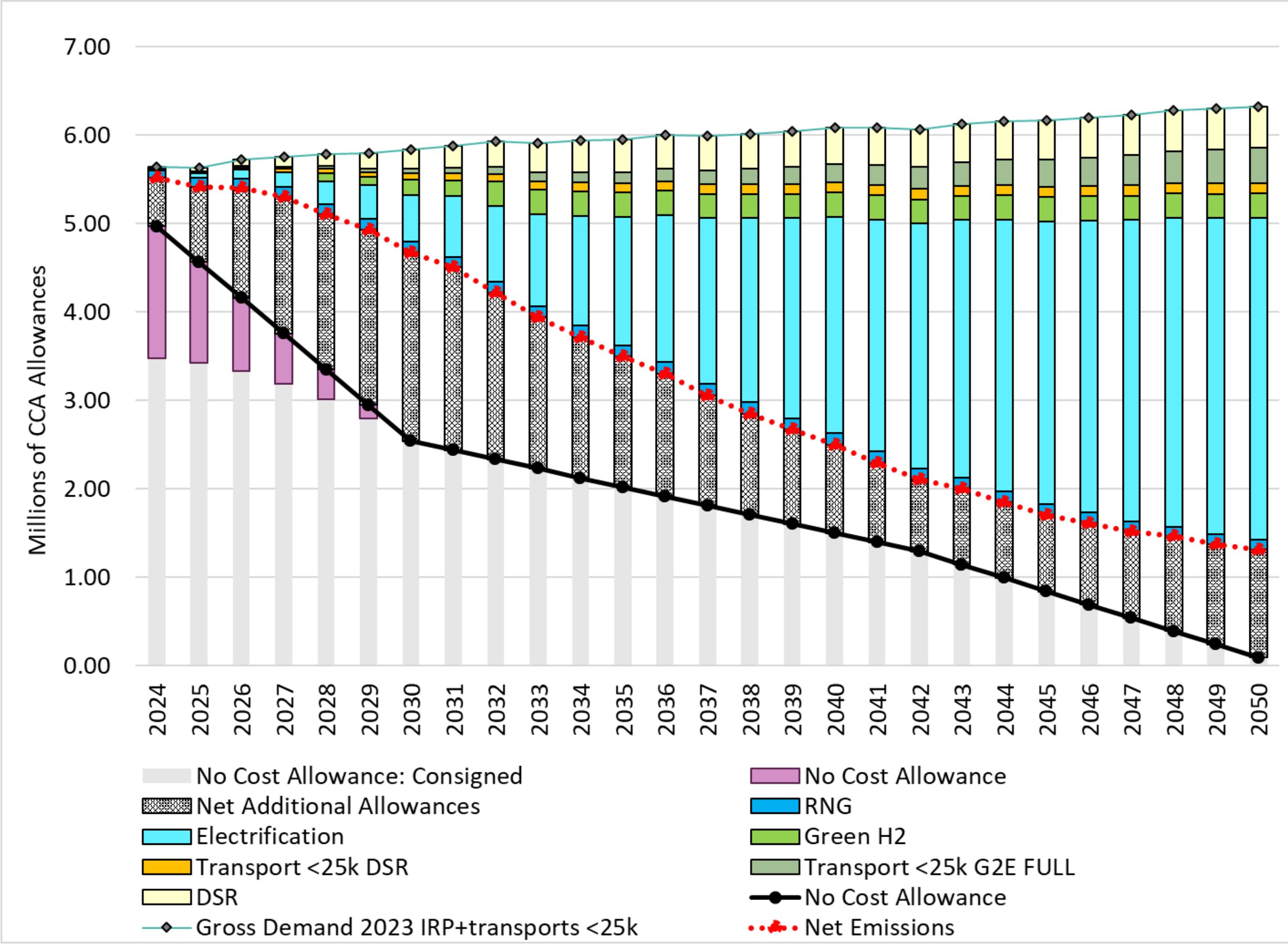


Figure F.20: Hybrid Heat Pump Adoption Policy — Demand-side Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.21: Hybrid Heat Pump Adoption Policy — CCA Emissions



F — Zero Gas Growth

This sensitivity looks at the impact of zero-gas customer growth. Portfolio additions represent the least cost builds for that scenario or sensitivity.

Figure F.22: Zero Gas Growth — Portfolio Additions

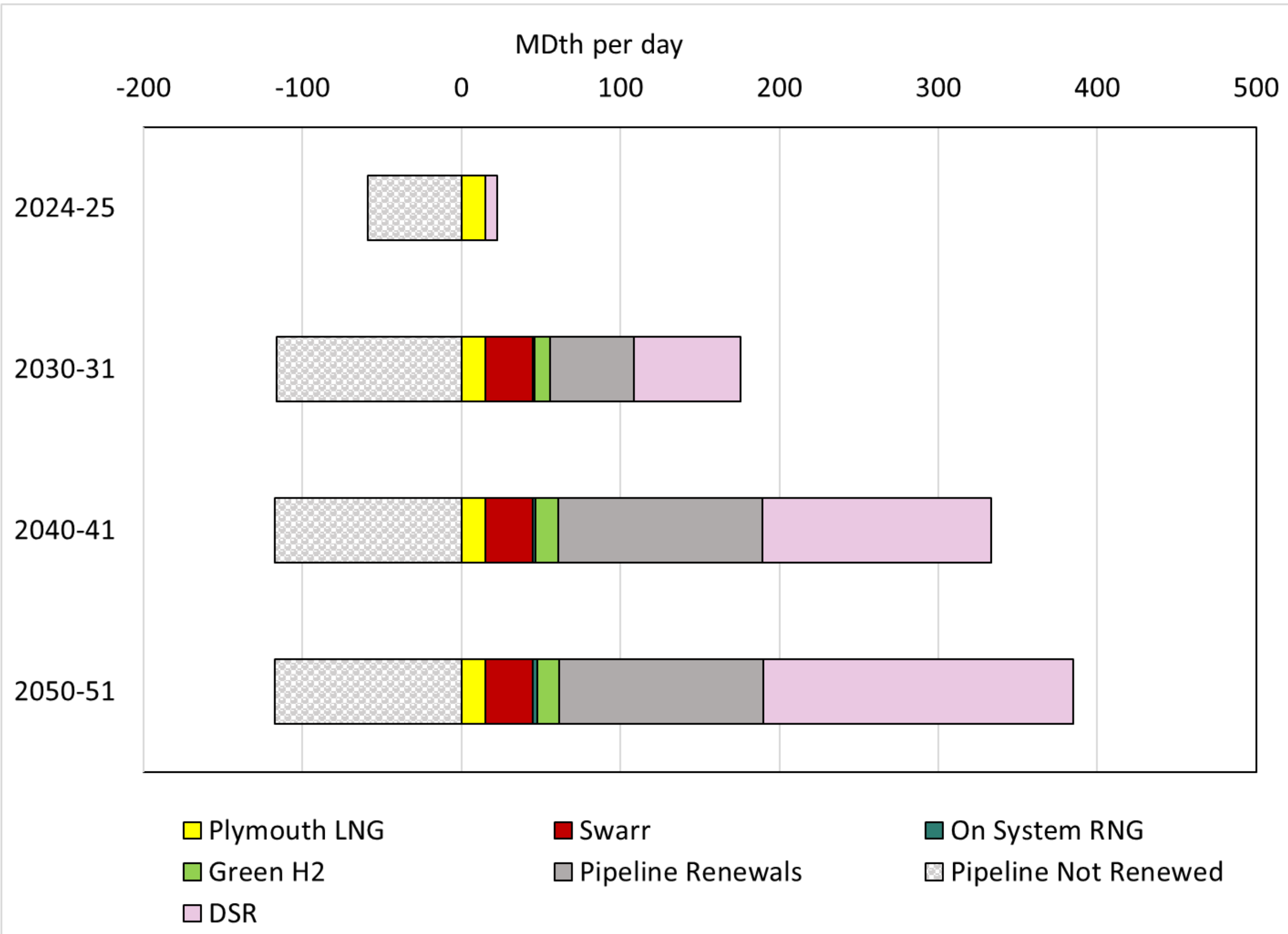
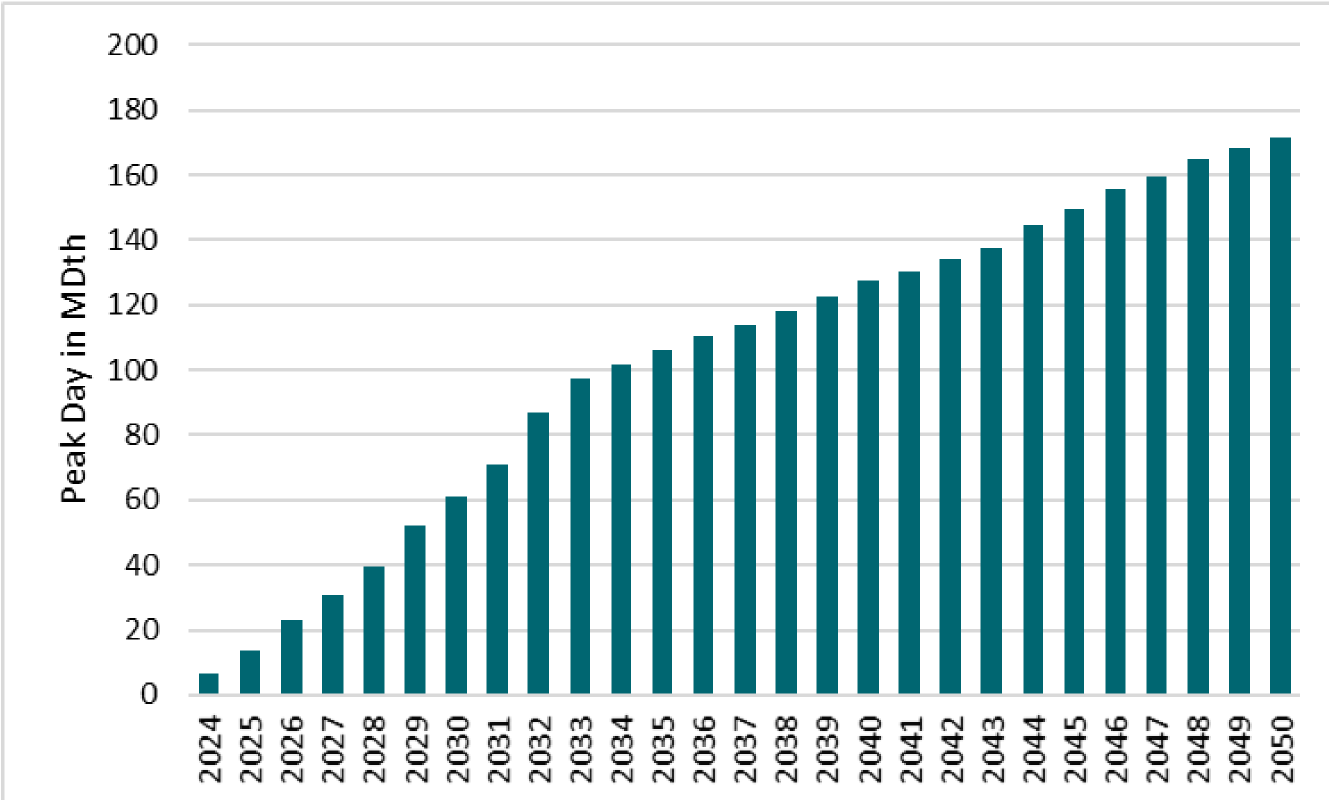
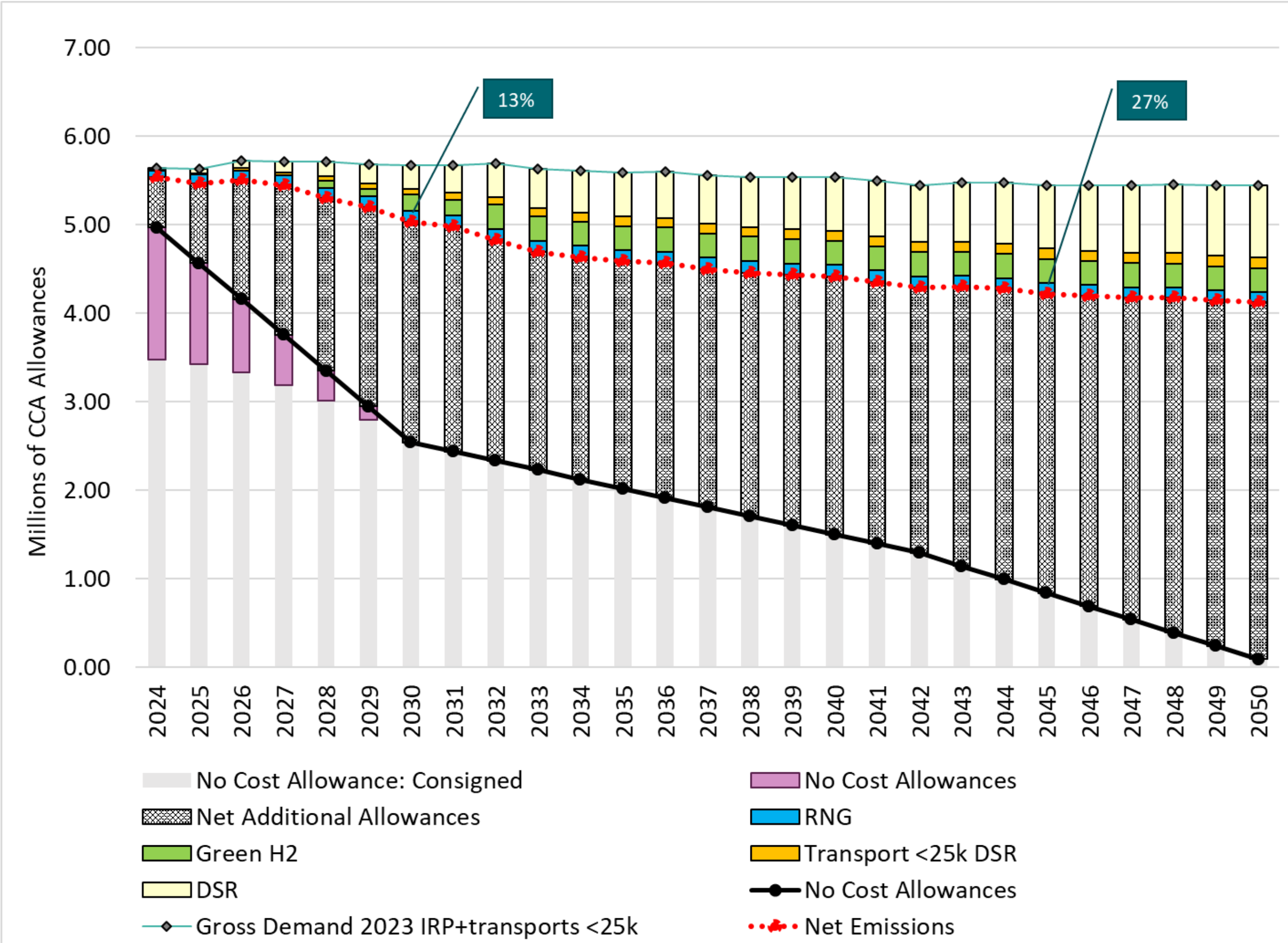


Figure F.23: Zero Gas Growth — Demand-side Resources Additions



Data for portfolio additions is in the output data files on the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.24: Zero Gas Growth – CCA Emissions



G — High Gas Prices

Portfolio additions represent the least cost builds for that scenario or sensitivity.

Figure F.25: High Gas Prices - Portfolio Additions

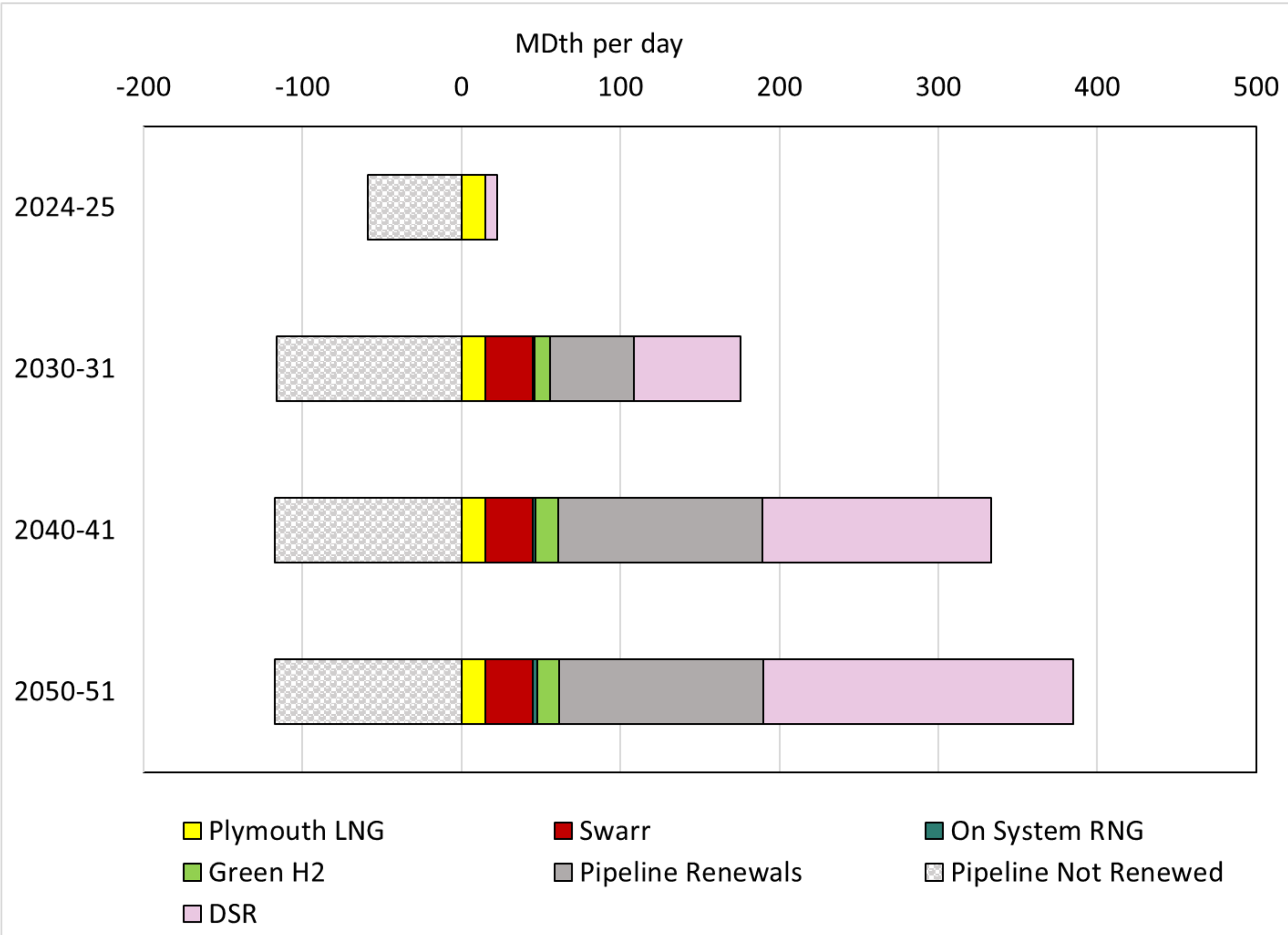
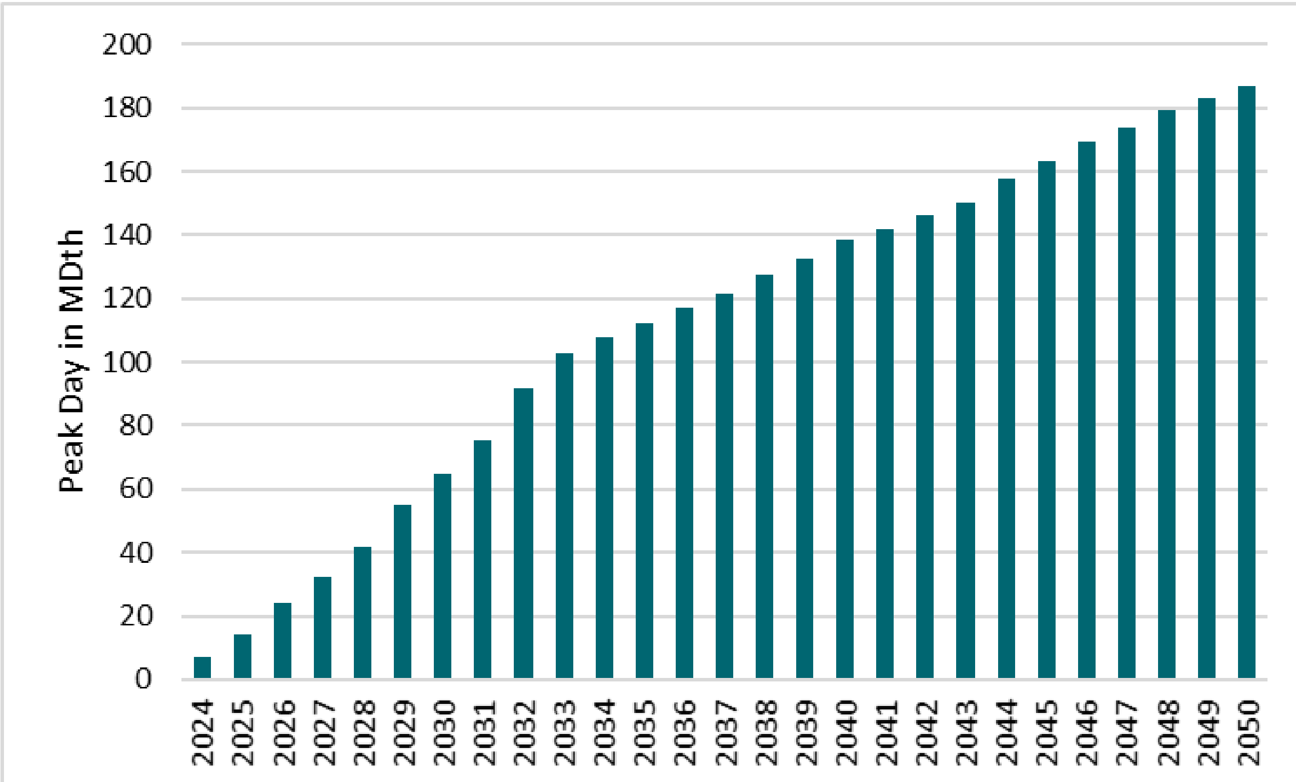
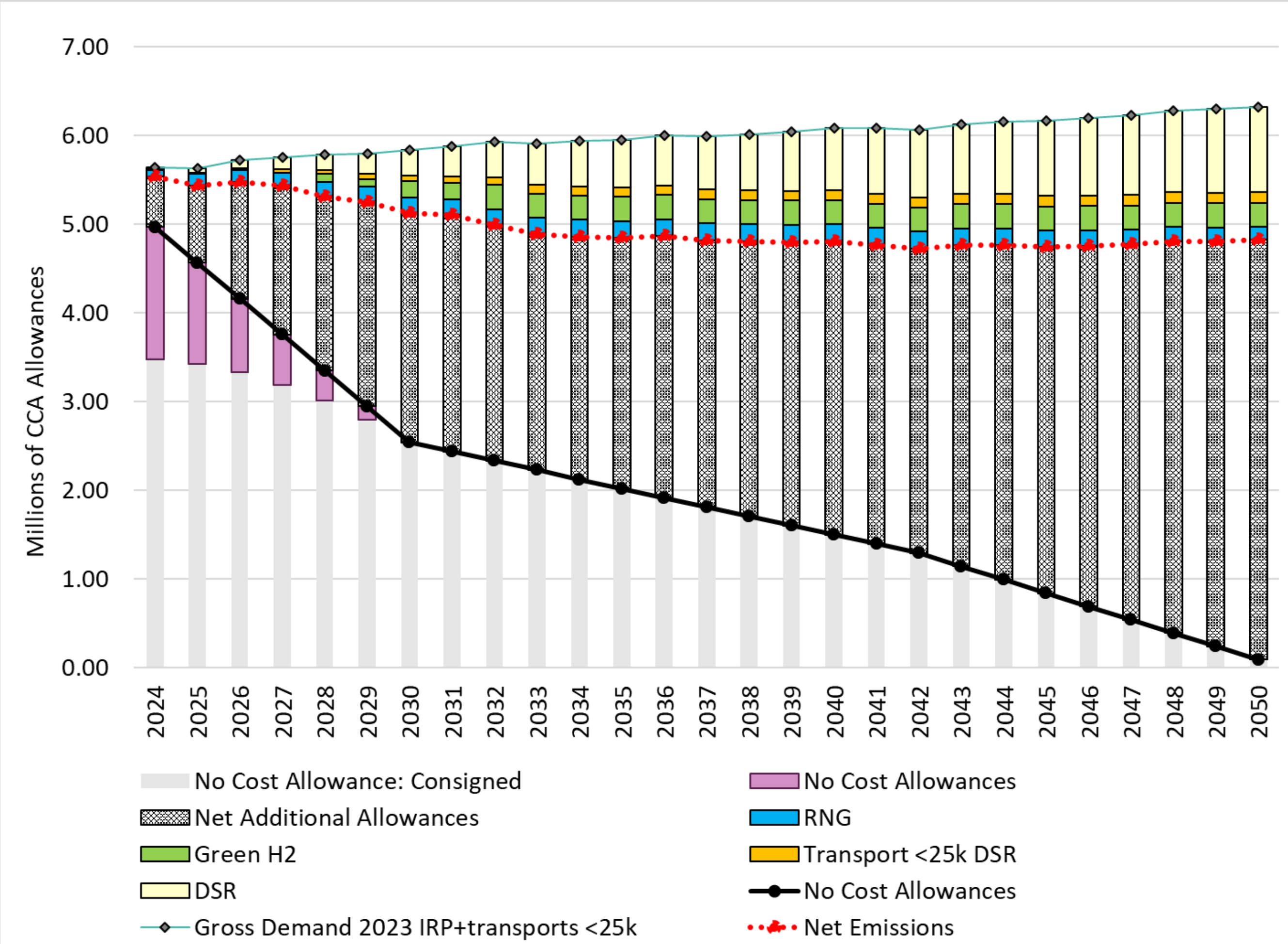


Figure F.26: High Gas Prices - Demand Side Resources Additions



Data for portfolio additions is in the output data files uploaded to the 2023 Gas Utility IRP website. We based the emissions profile for the portfolios on the least-cost portfolio in that scenario or sensitivity.

Figure F.27: High Gas Prices — CCA Emissions



DELIVERY SYSTEM PLANNING
APPENDIX G

PUGET SOUND ENERGY

Contents

1. Introduction

Puget Sound Energy's (PSE) energy delivery system is the network of distribution and transmission wires and pipelines that deliver energy from the energy source to the customer meter. We design our system to deliver energy safely, reliably, affordably, cleanly, and on-demand under all system conditions. Our system design plans include actions to meet all regulatory requirements, including North American Electric Reliability Corporation (NERC) standards that govern the bulk electric system and Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations that govern pipeline safety. Crucially, we plan so we can meet our customers' future energy needs.

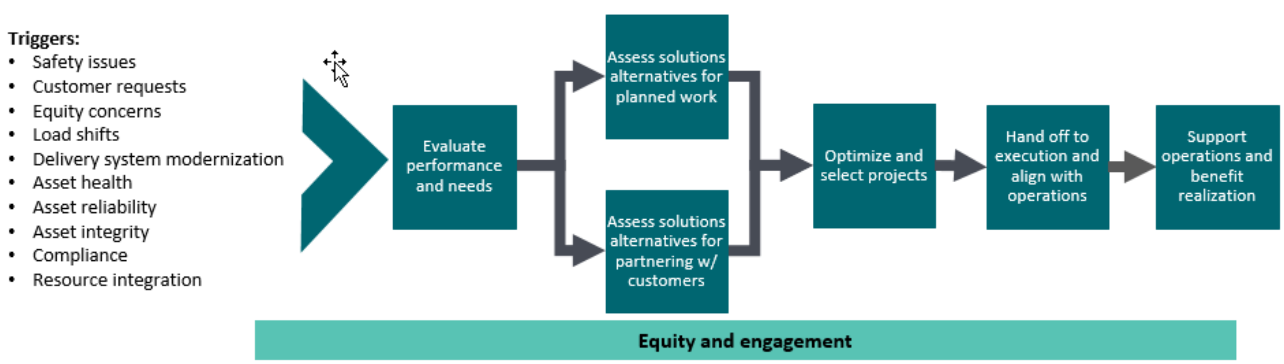
We also plan a flexible system that adapts to changes in customer use, advances in emerging technologies, and increased penetration of more diverse and distributed clean energy sources. We anticipate meeting future energy needs using a hybrid, complementary approach that balances electric, gas, and other energy sources (such as renewable natural gas and hydrogen) and delivers them optimally. We prioritize key foundational technology investments, specific asset hardening to improve reliability and resiliency to major events, intelligent demand-side management systems to optimize energy use, and backbone major infrastructure improvements. These efforts to modernize and improve our delivery system are necessary to meet regulatory requirements and future energy demand needs.

Meeting these needs and our decarbonization goals requires a flexible planning framework, a modern energy delivery system, a focus on research, and continuous improvement. Delivery System Planning (DSP) is the structured approach we use to analyze delivery system needs and potential solutions, prioritize the portfolio, ensure customer equity, and realize benefits.

2. Delivery System Planning

Pipeline and electric delivery system planners prepare 10-year plans as required for integrated resource plans (IRPs) and annual implementation plans. This section describes the current process for developing both types of plans.

Figure G.1: PSE Delivery System Planning Operating Model



We begin the PSE planning process with a needs assessment. Then we evaluate solution alternatives and recommendations. We start the needs assessment with county- and local-level load forecasts. We evaluate the system's current performance and future needs based on data analysis and modeling tools. Our planning considerations include internal inputs such as integrity indices, system performance, equity, company goals and commitments, and the root causes of historical 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. We identify recommended alternative(s) that will proceed to project planning if approved. We also identify the portfolio of projects that will proceed based on optimized benefits and costs for a given funding level, supported by approval in the company budget. The process is the same for both long- and short-term planning

2.1. Analysis Process and Needs Assessment

Many different critical factors drive energy delivery system needs. We consider these factors to identify the right system needs, as described in the next section.

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. However, demand is uneven within the service area, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is the most extreme. We carefully evaluate system performance during peak load periods each year, update system models, and compare these models against future demand and growth forecasts. These steps prepare us to determine where we need additional infrastructure investment to meet peak firm (committed) loads. Customer usage patterns determine the peak conditions we must design the delivery system to accommodate.

Our gas load is primarily residential. Therefore, peak conditions align with cold-temperature weather events that occur each year during the winter months, November–March. Every day, the greatest draw on the system occurs between 5 a.m. and 9 a.m., when most households begin their morning routine of waking up in a warm house, taking hot showers, and cooking morning meals. During these high-demand periods, the lowest pressures in the system occur. A system failure to meet these peak demands will result in low system pressures that cannot support the proper operation of customer equipment, affecting comfort and introducing safety risks. This situation requires the pipeline system operator to manually close each customer meter until proper delivery system pressures are reestablished, then subsequently perform a safety check and relight each appliance, further inconveniencing the customer. As a result, pipeline planning criteria are conservative to ensure the minimum pressures are maintained even during cold weather extremes.

Energy efficiency consists of measures and programs that upgrade or replace existing building components that affect energy use, such as heating, ventilation, water heating, insulation, and appliances with more energy-efficient options. These replacements can reduce peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress from peak loading, system imbalance, or in response to market prices participate in demand response (DR). Interruptible rates, which offer reduced costs for energy delivery to customers who agree to curtail use when requested, are a subset of demand response. When we use DR to relieve loading at critical times, it can reduce the need for increasing the capacity of traditional delivery infrastructure. We use interruptible rates in PSE's service area and depend significantly on curtailing these customers to meet demand.

Aging Infrastructure: Refreshing aging infrastructure is essential to modernizing the delivery system. Equipment that has reached the end of life creates integrity issues, potentially causing leaks or failure to operate when needed.

System Integrity: The Pipeline and Hazardous Materials Safety Administration (PHMSA) requires PSE to monitor and remediate pipeline transmission and distribution systems risks.

Operational Flexibility: The ability to isolate pipelines and transfer load is important when responding to unplanned and planned outages and performing necessary equipment maintenance.

Safety and Regulatory Requirements: These contractual and legal requirements drive action for immediate mitigation, and as a result, we identify and resolve them outside of this long-term planning process.

We review PSE's delivery system annually to ensure pipeline integrity and mitigate risk. Past leaks, equipment inspection, maintenance records, customer feedback, employee knowledge, and analytic tools identify areas where improvements are likely required and where such improvements mitigate risks to the public and PSE's customers. We collect 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 mitigate integrity concerns. We implement programs to address these risks, which often result in the replacement of assets or increased monitoring. Programs are also in place to manage aging infrastructure by replacing pipelines nearing the end of their useful life.

We included external inputs, such as new regulations, municipal and utility improvement plans, customer feedback, and company objectives, such as PSE's asset management strategy in the system evaluation. These inputs help us understand commitments and evaluate opportunities to mitigate impact and improve service at least cost. For example, the Washington Utility and Transportation Commission (Commission) issued a policy statement in 2012 allowing gas utilities to file a plan to replace pipes with a higher risk of failure. We considered PSE's commitment to this plan in the evaluation. In 2016, the National Transportation Safety Board (NTSB) recommended the pipeline industry develop guidance on safe pipeline operations to protect 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 provides tools needed to track and improve safety performance continuously and comprehensively. We obtain annual updates to local jurisdiction six-year Transportation Improvement Plans to gain a long-term planning perspective on upcoming public improvement projects. As transportation projects develop through design, engineering, and construction, we work with local jurisdictions to identify and minimize potential utility conflicts and seek opportunities to address system deficiencies and needs.

We rely on several tools to help identify needs and operational concerns and to weigh the benefits of alternative actions to address them. Table G.1 summarizes these tools, the planning considerations (inputs) that go into each, and the results (outputs) they produce. We use each tool to provide data independently and then put it in our investment decision optimization tool (iDOT), which creates an understanding of the benefits and risks.

Table G.1: Natural Gas Delivery System Planning Tools

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

Note: Puget Sound Energy's pipeline system model is a large integrated model of the entire delivery system using a software application (Synergi® Gas) that is updated to reflect customer loads and system and operational changes. This modeling tool predicts capacity constraints and system performance in various temperatures and under different load or gas blend scenarios. We compare results to actual system performance data to assess the model's accuracy.

Modeling is a three-step process. First, we build a map of the infrastructure and its operational characteristics using geographic information (GIS) and asset management systems. For pipelines, these details include the diameter, roughness, and length of the pipe, connecting equipment, regulating station equipment, and operating pressure. Next, we identify customer loads, specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or telemetry readings. Finally, we take into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the heat content of the fuel, the status of components (valves or switches closed or open), and forecast future loads to model scenarios of infrastructure or operational adjustments.

Our goal is to find the optimal solution to a given issue. Where issues surface, we use the model to evaluate alternatives and their effectiveness. We augment potential options with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for current and future loads.

The performance criteria at the heart of PSE's infrastructure improvement planning process are:

- Safety and compliance with all regulations and contractual requirements (100 percent compliance).
- The ability to remove equipment from service for maintenance and provide flexibility for emergency response.
- The heat content of the fuels to meet tariff requirements (985 BTU per cubic foot).

- 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 maximum pressure acceptable in the system (defined by CFR 192.623[1] and WAC-480-93-020[2]).
- The minimum pressure that must be maintained in the system (the level at which appliances fail to operate).
- The nature of service each type of customer has contracted for (firm or interruptible).
- The temperature at which the system is expected to perform (52 DD Peak Hour).

We begin our evaluation by reviewing existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations, and opportunities. Planning triggers are specific performance criteria that indicate the need for a delivery system study. There are different triggers or thresholds for transmission, bulk distribution (high pressure) and distribution (intermediate pressure), capacity, and reliability. We identify a need when performance criteria are not met.

We expect the planning assumptions, guidelines, and performance criteria to change over time due to the evolving policies pursuing electrification, demand-side resources at the local neighborhood level, and deferral of traditional infrastructure investments in favor of new technologies. We expect delivery system planning margins to increase to account for greater uncertainty of loads due to variability of participation in behavior-based conservation and demand response programs. Puget Sound Energy's delivery system planning assumptions relative to conservation and demand response have historically incorporated outputs generically at a high level, but these assumptions, while appropriate for resource planning, may not be suitable for local neighborhood decisions and reliability until such programs reach greater maturity. Higher cost conservation is likely customer-type specific, and as a result, greater study and specific application of targeted conservation programs are necessary for conservation to be reliable. We may also need to develop assumptions regarding demand response program participation, as customer adoption may change as home occupancy changes over time.

We engage with Commission pipeline safety staff in various forums, such as annual audits and quarterly roundtable discussions that also inform our planning considerations.

2.2. Solutions Assessment and Criteria

We list the alternatives available to address delivery system capacity, integrity, aging infrastructure, and operational flexibility in Table G.2. Each option has its costs, benefits, challenges, and risks. We included traditional pipeline solutions and non-pipe alternatives in the analysis.

Table G.2: Alternatives to Address Delivery System Capacity and Reliability

Alternatives	Pipeline System
Add energy source	City-gate station, district regulator, alternate fuels like renewable natural gas and hydrogen blended gas
Strengthen feed to the local area	New high-pressure main, new intermediate pressure main, replace main

1 CFR 192.623
2 WAC-480-93-020

Alternatives	Pipeline System
Improve existing facility	Regulation equipment modification, uprate system
Load reduction	Conservation, load control equipment, possible new tariffs

We also manage short-term issues like peaking events or temporary conditions created by a pipeline construction project through deployment of temporary sources or operational actions such as the following:

- 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

2.2.1. Non-pipe Alternative Analysis

Our non-pipe alternative analysis is a screening process that breaks down evaluation of utilizing existing resources, applying emerging technologies like renewable natural gas injection and hydrogen blending, or reducing customer demand. We perform an economic and feasibility analysis whose results provided a recommended solution. The planning process compares alternatives, seeking the least-cost solution that maximizes value for customers and interested parties. We evaluated a traditional pipeline solution, a full non-pipe solution, and any potential hybrid options that fit the program.

Puget Sound Energy has historically used non-pipe alternatives like CNG injection, system uprates, and even an LNG Peak shaving facility. We are monitoring and investigating technologies that will be beneficial low-carbon alternatives in the future, including renewable natural gas injection or hydrogen blending into the supply to meet a localized need. Additionally, we are advancing the load reduction alternatives. Such options may depend on customer participation for siting, control, or actionable behavior, and seek to continue developing our understanding and confidence in these as permanent solution alternatives. These alternatives include greater use of demand response through smart thermostat technologies, and higher efficiency and hybrid or dual-fuel customer heating equipment.

In 2018–2019, we piloted a gas demand-response program to determine the potential for peak capacity reductions using smart thermostats. In 2022, PSE's Virtual Power Plant software phase one was implemented for demand response and was used in pilots in Bainbridge Island (electric) and in the Duvall (gas) area to address system needs. An additional pilot area is being planned for Bonney Lake area. Pilot results allow us to evaluate the potential for using demand response as an NPA to delay supply and distribution investments. We will continue to build on our demand response experience to help determine what role this new tool can play in alternatives to pipeline infrastructure. We will also leverage demand-side resources through reliable local programmatic energy efficiency offerings. Lessons from our pilot will benefit local applications we use to manage loads and defer infrastructure investments. We anticipate leveraging energy-saving technologies will address some local delivery system constraints, but not all, with effectiveness subject to local characteristics of each area.

Puget Sound Energy has a targeted electrification pilot planned in 2023–2024 that will inform a strategy to be published in 2025. This will include a framework for a benefit-cost analysis of targeted electrification as a non-pipe alternative to address integrity, operational, or reliability concerns.

2.2.2. Criteria and Evaluation

We establish technical and non-technical solution criteria to ensure implemented solutions fully address the needs. Based on the needs identified, we perform a solutions study where we develop project alternatives. Solutions studies consider opportunities to partner with customers, PSE programs, or a PSE pilot. We vet the solution alternatives and evaluate them against specific solution criteria. Technical solutions must meet all performance criteria as we described. We also assess how to avoid adverse impacts on system integrity or operating characteristics, how long the solution will last, and whether it will delay the need for additional investments for a specified time. We also consider our customers' rate burden as PSE recovers investments. Non-technical solution criteria include permitting feasibility, 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, we compare the relative costs and benefits of various solutions (projects) using iDOT, a project portfolio optimization process and tool. Based on PowerPlan's Asset Investment Optimization (AIO) software, iDOT allows us to capture project and program criteria and benefits and score them across 13 factors associated with five 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, alignment with interested parties, 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 to help us evaluate infrastructure solutions.

We calculate project costs using various tools, including historical cost analysis and unit pricing models based on estimated engineering costs and service provider contracts. We refine cost estimates as projects move through detailed scoping. Through this process, we review alternatives and vet recommended solutions through an internal peer review process. Projects that address routine infrastructure replacement are proposed at a program level and incorporated into a parallel path in the iDOT process. We use risk assessment tools to prioritize projects within these programs; for example, we prioritize vintages of wrapped steel and polyethylene facilities for replacement based on known risks such as leak history, pipe condition, and the pipe's proximity to certain structures.

The iDOT tool also helps us examine projects in greater detail than a simple cost/benefit analysis. The iDOT software includes health and safety improvements, environmental impact, sustainability, customer value, and interested party. As a result, projects that contribute intangible value receive due consideration in iDOT.

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 customers, interested parties, and PSE relative to given financial constraints. We make additional minor adjustments to ensure the portfolio addresses resource planning and other applicable constraints or issues, such as known permitting or environmental process concerns. We have periodically reviewed this process, the optimization tool, and the resulting portfolio with Commission staff.

iDOT builds a hierarchy of the value these benefits provide against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure we assign proper weight and priority throughout the evaluation process. In 2022, we changed the underlying tools that enable the iDOT process from Price Waterhouse Cooper's (PWC) Folio to PowerPlan's Asset Investment Optimization tool. In 2023, we will update the benefits to include equity considerations and a specific carbon emissions reduction or methane emissions reduction benefits. In 2023, we will also determine how best to incorporate interested party input into the benefit review and weighting process.

Our delivery system planning process will mature as we better understand the customer benefit assessment process prescribed in the Clean Energy Transformation Act (CETA). The CETA-required advisory group engagements will help us further refine the definitions of energy security and resilience and guide how we consider and apply energy and non-energy benefits relative to vulnerable populations and highly impacted communities. We will also participate in a commission led Distributional Equity Analysis that will continue our methodology

2.3. Project Planning and Implementation Phase

Once we complete the described process for a particular project and portfolio and senior management reviews and approves it for funding, the initiation phase is complete, and we start the project planning phase. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects, we may capture this in our SAP software system through a notification process or supported by a business case that addresses needs with programs. The project planning phase involves developing detailed engineering and technical specifications, pursuing real estate rights-of-way, planning communications, and considering potential coordination with other projects in the area. We assess implementation risks and develop mitigation plans. Puget Sound Energy's 10-year plan, included in Section 3 of this document, reflects the projects we are initiating. Once we move a project to the project planning phase, we have established the need; IRP engagement ends, and community engagement begins.

Once we have reviewed the project need and initiation recommendations, we develop annual and two-year work plans for project planning and implementation feasibility. We coordinate work plans with other internal and external work and resource plans. We make final adjustments when we compare the system portfolio with other company objectives, such as necessary generator, dam work, or customer initiatives. Although we consider annual plans final, we adjust them throughout the year based on changing factors such as public improvement projects that arise or are deferred, changing forecasts of new customer connections, or project permitting delays 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. We may review alternatives through project lifecycle phase gates and detailed routing and siting discussions.

We communicate long-range plans to the public through local jurisdictional tools such as the city and county comprehensive plans required by the Washington State Growth Management Act. This information often demonstrates to local jurisdictions, residents, and businesses the need for improvements well before a project is in the project planning, design, permitting, and construction process. We post updated project maps and details on PSE.com.

3. Pipeline Delivery System

Puget Sound Energy delivers gas with pipes and pressure regulating stations. Puget Sound Energy's pipeline delivery system is responsible for providing gas safely, reliably, and on demand. We must also meet all regulatory requirements that govern the system. To accomplish this, PSE must do the following:

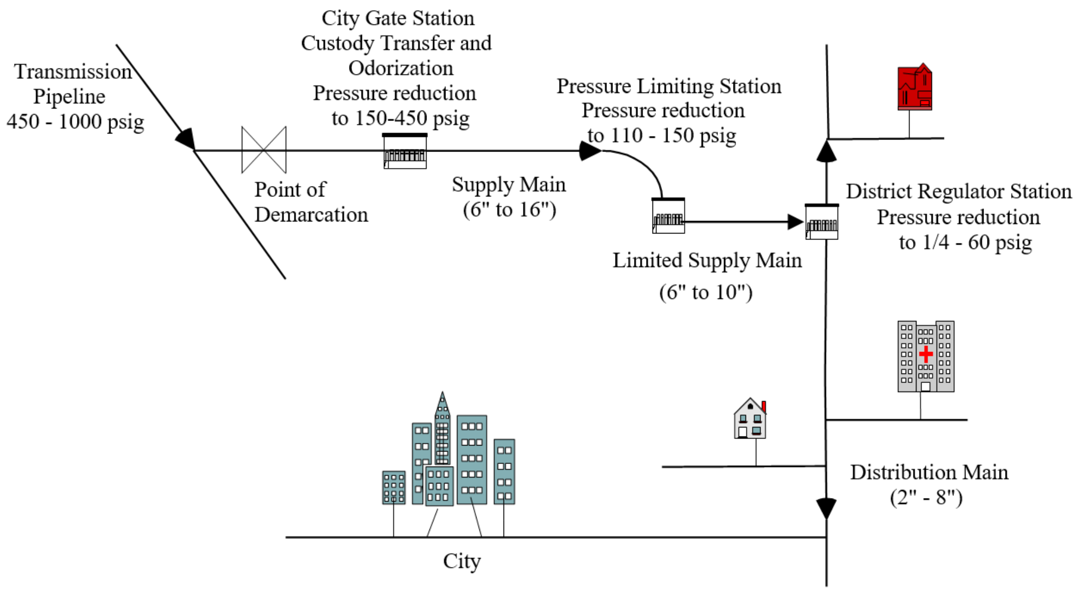
- Address reliability performance and system integrity concerns
- Integrate gas supply resources owned by PSE or others
- Meet both peak demands and day-to-day demands at the local and system levels
- Meet state and federal regulations and complete compliance-driven system work
- Monitor and improve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

Our goal for the planning process is to fulfill these responsibilities as cost-effectively and equitably as possible. We use this process to evaluate system performance to bring issues to the surface, identify and evaluate possible solutions, understand impacted customers, and explore potential alternatives' costs and consequences. This information helps us make the most effective and cost-effective decisions.

3.1. How the Pipeline Delivery System Works

Utilities transport gas at a variety of pressures through pipes of various sizes (see Figure G.1). Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge (psig)) to city gate stations. City gate stations reduce pressure to 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. The gas then flows through a network of piping (mains and services) to a meter assembly at the customer’s site, where pressure is reduced to what is appropriate for the operation of the customer’s equipment (0.25 psig for a stove or furnace). A meter tracks how much the customer uses.

Figure G.2: Illustration of Pipeline Delivery System



The gas pipeline system in the United States was first built in the late 1800s and eventually expanded into a networked, two-way flow. Pipeline materials and operating pressures have changed over time. Gas was not introduced to the Puget Sound region until 1956, using higher pressures and smaller diameter pipes because of changing technologies. Now, new plastic pipes replace older cast iron pipes to cost-effectively renew existing infrastructure in urban areas. Although the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Because gas pipelines are often located in increasingly congested rights-of-way, protecting pipelines from damage is even more critical than ever.

3.2. 10-year Pipeline Delivery System Plan

The gas resource planning process focuses on conservation and demand-side resources and the future of low-carbon alternative fuels. In the next decade, we will modernize the pipeline system to:

- Address major backbone infrastructure needs
- Ensure pipeline safety
- Reduce greenhouse gas emissions

Puget Sound Energy's modernization of the pipeline system and focus on safety will provide more opportunities for programs such as demand response and position the pipeline system to be agnostic to fuel type as alternative fuel supply chains mature, supply increases, and costs decrease. The 10-year pipeline infrastructure plan includes vital investments in multiple areas.

The key investment areas discussed in the following pages are interrelated. Our 10-year plan addresses needs that are either existing or predicted based on the processes described in section two of this document. We conduct delivery system studies yearly, which surface new needs or constraints in future 10-year plans. In addition, the latter years of the plan may change substantially in this time of energy and load evolution. This 10-year plan provides direction to inform decisions about specifically funded actions and plans.

3.2.1. Improve Visibility, Analysis, and Control

Advanced Metering Infrastructure (AMI): Puget Sound Energy is in year four of replacing the current aging and obsolete Automated Meter Reading (AMR) system and gas customer modules with Advanced Metering Infrastructure (AMI) technology. This new AMI technology is an integrated system of smart modules, communications networks, and data management systems that give PSE and our customers greater visibility into customer use and load information. It enables two-way metering between PSE and its customers.

Data and Control: We have modernized monitoring tools, replacing manual field charts with digital equipment, and will continue to evaluate the greater use of automated valves to provide control where needed.

3.2.2. Reduce Greenhouse Gas Emissions

Eliminating Leaks and Methane Release: We will continue to eliminate leaks from the pipeline system, eliminating all non-hazardous[3] leaks as we find them by the end of 2022. We will continue to evaluate operating practices and methods to further minimize methane releases, for example, by increasing contractor awareness when working around pipelines to prevent damage during construction, repairing leaks more quickly than regulations require, or capturing gas when construction work requires pipelines to be depressurized and purged.

Cleaner Fuels: Puget Sound Energy has integrated some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and we will continue to look for innovative ways to harvest more RNG, streamline interconnection, and remove obstacles.

Over the last few years, we have evaluated the advantages of mixing various renewable, zero/lower carbon fuels (including hydrogen) into our existing natural gas. These evaluations have aimed to assess options to reduce our carbon emissions. During this research and learning phase, it has become evident that it will be necessary to extend our knowledge and practical experience of mixing renewable, zero/lower carbon fuels into our existing natural gas stream. We are currently accomplishing this in a limited manner by combining bio-methane and waste-based renewable natural gas with our natural gas in limited locations on our gas system. As we continue this research into renewable, zero/lower carbon fuels, it is apparent that the next logical step is to obtain additional first-hand experience with these fuels by completing demonstration and pilot projects especially related to hydrogen blending.

Demonstrations and pilot projects are the best way to obtain the experience, technical skills, and operations experience needed to safely blend these fuels with minimal impact on customer end-use applications. This demonstration and pilot project approach leverages current industry research and experience and allows us to seek partnership opportunities where necessary. We can also perform PSE-led demonstrations and functional pilot projects to begin answering outstanding questions and increase confidence, skills, and the training required to move to

[3] Hazardous leaks require immediate repair or repair within defined timeframes.

hydrogen mixing as quickly and efficiently as possible. The focus of these demonstration and pilot projects concerning hydrogen mixing in the near term include but are not limited to confirming the following areas:

- A blend of 10 percent to 20 percent of hydrogen (by volume), supported by PSE's existing gas system piping, customers, and natural gas supplies
- Impact on commercial/industrial customer equipment
- Pipeline integrity
- Residential and commercial customer appliances can use a low-level blend with minimal impact on equipment
- Safety protocols with hydrogen blends, including odorant, leak detection, and response

The scope listed above would also help inform additional future hydrogen mix strategy demonstrations and pilot projects as we progress toward reducing carbon emissions.

3.2.3. Ensure Pipeline Safety and Reliability

Ensuring a Healthy System: To provide overall reliability and safe operations, we expect to replace or upgrade the following system components in the next 10 years. Other steps we will implement to ensure a healthy system include:

- Continuing PSE's industry leadership in mitigating sewer cross bores[4]
- Deploying 34 programs to address pipeline safety risks associated with pipelines, pressure regulation equipment, and meters
- Investing more in risk mitigation programs under the recently passed Pipeline Reauthorization Act Rules
- Pipeline and Hazardous Materials Safety Administration (PHMSA) new requirements for transmission pipelines
- Remediating buried customer meter set equipment
- Replacing 200 to 300 miles of gas main (for example, DuPont pipelines that are prone to catastrophic failure)

Maintaining System Reliability: With real possibilities to reduce carbon emissions by increasing the use of renewable natural gas and blending alternative fuels such as hydrogen with gas, we will continue to address system needs to meet customer choice expectations. We will continue to develop and deploy non-pipe alternatives (NPA) like demand response technologies and targeted electrification that help offset increased loads because of customer growth or changes in fuel heat content.

3.2.4. Maintain Strong Security, Cyber Security, and Privacy

As critical infrastructure becomes more technologically complex, it is even more crucial for PSE to adapt and mature the physical security of critical assets and cybersecurity practices and programs to take advantage of new technology opportunities such as Internet of Things (IoT) devices. To ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape, we utilize a variety of industry standards to measure maturity. We also foster strong working relationships with technology vendors to ensure their approach to cybersecurity matches our expectations and needs. Puget Sound Energy's telecommunications strategy will evolve to support

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[4] Sewer cross bores occur when gas pipe, installed by bore technologies, crosses through unlocatable sewer pipes.

required security and reliability, leveraging existing communication networks such as the AMI communication mesh network.

3.2.5. Major Backbone Infrastructure Projects

Major infrastructure projects are driven by reliability needs and proceed in two phases. The initiation phase includes developing the need, evaluating alternatives, and identifying a proposed solution. The implementation phase includes project planning, for which we test the need and proposed solution, and then design, permitting, and construction begin. Once a project is in implementation, location-specific activities begin, including engagement with the local community. We provide informational updates to customers through the IRP process for projects in this phase. We are working to develop more detail and engagement with the customers when a project is in the initiation phase.

Lessons learned from the PSE demand response pilot support the 2023 Gas Utility Integrated Resource Plan preferred portfolio that identifies the opportunity to meet increasing resource needs using conservation, demand-side management, and targeted electrification programs. As we learn more, we will continue to screen new needs for NPA potential to support this forecast and refine data and tools.

We currently have no major backbone projects in the implementation phase.

➔ See Chapter Six: Gas Analysis for NPA analysis process.

3.3. Major Pipeline Projects Planning Process

We begin studying an area with a needs assessment when specific study triggers affect system reliability, including critical gas pipeline pressures and flows, load/customer growth projections, gas supply contracts, excessive cold weather actions (CWAs), and other information.

We gather data and make assumptions with the following guidance.

Planning Study Triggers:

- Gas customer outages
- Increased CWAs
- Maximum flow guidelines are reached
- Minimum pressure guidelines are crossed
- Safety or risk mitigation

Modeling Assumptions:

- The latest PSE load forecasts factor in localized system performance and growth.
- The loads in the model contain no interruptible loads for these studies.
- The projected heat content for the models includes the resource plan results.
- We baselined all models against actual flows, loads, and pressures to ensure accuracy.

- We used the latest PSE gas models that contain all pipes down to the service level and the latest gas load files. We calculated gas loads for every gas customer on our system based on their history and then temperature-compensated this and applied it to the models.

Solution criteria include technical and non-technical measures that must be met. We developed solutions criteria for system performance in reliability, cost, and constructability.

Technical Solution Criteria:

- Must address all relevant needs identified in the needs assessment report
- Must be able to meet a 25-year planning horizon — staging (phased approach) is acceptable
- Must be safe
- Must meet all performance criteria for supply and distribution system requirements, including reliability
- Must not cause any adverse impacts on the reliability or operating characteristics of PSE's system

Non-Technical Solution Criteria:

- Constructible to meet capacity need dates, both current and future
- Meet environmental impacts and permitting requirements
- Must assess and account for community and transportation impacts
- Reasonable, prudent project costs
- Utilize proven/mature technology

3.4. Major Pipeline Projects in Initiation Phase

We have three projects in the initiation phase summarized in Table G.3. We also include specific project descriptions in the following pages with summaries of the need and potential solutions evaluated, including NPAs.

Table G.3: Summary of 10-year Major Pipeline Implementation Projects

Major Pipeline Projects	Date Needed	Need Driver
Bonney Lake Reinforcement Project	Existing	Reliability and Operational Flexibility
North Lacey Reinforcement Project	Existing	Reliability and Operational Flexibility
Gas Reliability Marine Crossing	Existing	Reliability, Operational Flexibility, and Aging Infrastructure

3.4.1. Bonney Lake Reinforcement

The Bonney Lake study area includes the Lake Tapps and South Prairie areas, with approximately 20,000 residential and commercial gas customers.

Estimated need date: Existing

Date need identified: 2008

Needs assessment: A high-pressure gas supply system needs assessment was performed for the Bonney Lake Study area. This needs assessment determined that a long-term supply solution should be developed for the area while continuing to deploy CWAs to address immediate reliability concerns.

Needs identified: The current high-pressure supply system is undersized and falls below current design requirements during a peak demand event for existing gas loads.

- **Operational flexibility:** Three CWAs are scheduled for this area along with 100 percent curtailments; actions markedly insufficient to address the reliability concerns. Manual operations carry an inherent operational risk that an action may not be possible when needed due to weather and road conditions and/or equipment and personnel issues. There are limitations to manual operations based on location and availability of sufficient equipment and trained personnel.
- **Reliability:** The growth in the Bonney Lake area since 2013 has averaged four percent per year. The system cannot meet minimum design requirements without manual operations (see operational flexibility in the next bullet). The potential for gas customer outages exists.

Current Status: The needs assessment is complete, and we expect the study process for traditional pipeline solutions and NPAs to be completed in early 2023.

3.4.2. North Lacey Reinforcement

The North Lacey area includes Lacey and the north and east Olympia areas and serves approximately 21,000 customers. The project will reinforce the Olympia system.

Estimated need date: Existing

Date need identified: 2009

Needs assessment: The supply system needs reinforcement to serve recent customer loads. The models show significant low-pressure issues when we consider pipeline restrictions.

Needs identified: The current high-pressure supply system is undersized and falls below current design requirements during a peak demand event for existing gas loads.

- **Operational flexibility:** We have two CWAs scheduled for this area with 100 percent curtailments. These actions are markedly insufficient to address the reliability concerns. Manual operations carry an inherent operational risk that an action may not be possible when needed due to weather and road conditions and/or equipment and personnel issues. There are limitations to manual operations based on location and availability of sufficient equipment and trained personnel.
- **Reliability:** The supply system cannot meet minimum design requirements without manual operations. The downstream distribution system cannot maintain adequate system reliability when the upstream supply system cannot maintain itself.

Current Status: We expect to complete the detailed needs assessment and alternatives review in 2023.

3.4.3. Gas Reliability Marine Crossing

The marine crossing in King County serves roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island.

Estimated need date: Current

Date need identified: 2018

Needs assessment: A high-pressure gas supply system needs assessment was performed for the Gig Harbor peninsula, Vashon Island, and Maury Island area. This needs assessment determined that a long-term supply solution should be developed while creating a backup supply solution for the area.

Needs identified: The dynamic marine environment in which this crossing has operated for more than 50 years has resulted in the need for reinforcement or replacement of parallel 8-inch undersea high-pressure laterals. Seafloor movement and fatigue induced by ocean currents have resulted in the crossing nearing the end of its service life.

- **Aging infrastructure:** Segments of the undersea pipeline infrastructure have maintenance concerns requiring mitigation.
- **Operational flexibility:** The existing marine crossing is the only gas pipeline supply to roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island. Although PSE's Gig Harbor liquid natural gas (LNG) facility augments the supply to meet system peak loads, a pipeline connection is required to maintain gas service to all customers in the area.
- **Reliability:** The supply system cannot meet minimum design requirements should the lateral exceed fatigue limitations. As a result, the downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system cannot maintain its system pressure.

Solution assessment: We developed solutions criteria in capacity, reliability, cost, constructability, and customer impact.

Solution criteria:

- Must be able to be constructed and permitted within a reasonable timeframe
- Must have reasonable project costs
- Must have the most negligible customer impact
- Must meet all technical criteria
- Must use mature technology

Evaluation of solution alternatives: We are completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions to determine the most cost-effective solution for this area's need.

Current Status: Project initiation to review alternative solutions is in progress, and we expect to complete it in 2023. We expect to complete system modifications to enable the operation of an emergency backup supply plan in 2023;

this will ensure we meet customers' needs should the marine crossing experience a failure before the project is completed.