ELECTRIC PROGRESS REPORT APPENDICES A–L

2023

PUGET SOUND ENERGY

2023 ELECTRIC PROGRESS REPORT

TABLE OF CONTENTS

PSE PUGET SOUND ENERGY

Table of Contents: Appendices

Appendix A: Public Participation

1. Introduction
2. Public Participation Approach
3. Participants
4. Timeline, Meetings and Topics
5. Meeting Documentation

Appendix B: Legal Requirement

1. Introduction
2. Regulatory Requirements

Appendix C: Existing Resource Inventory

1. Introduction
2. Supply-side Resources
3. Demand-side Resources

Appendix D: Generic Resource Alternatives

1. Introduction
2. Renewable and Storage Resource Technologies and Assumptions
3. Thermal Resource Technologies and Assumptions
4. New Resource Technologies and Assumptions
5. Resource Technologies Not Modeled
6. Tables

Appendix E: Conservation Potential and Demand Response Assessments

1. Introduction
2. Treatment of Demand-side Resource Alternatives
3. Distribution Efficiency

Appendix F: Demand Forecasting Models

1. Introduction

2. Model Estimation
3. Base and Final Demand
4. Stochastic Demand Forecasts
5. Climate Change Assumptions

Appendix G: Electric Price Models

1. Introduction
2. 2021 Integrated Resource Plan
3. Modeling Power Prices
4. Electric Price Forecast Results
5. Electric Price Stochastic Analysis

Appendix H: Electric Analysis and Portfolio Model

1. Introduction
2. AURORA Electric Price Model
3. AURORA Portfolio Model
4. Modeling Inputs
5. Embedding Equity
6. Financial Assumptions
7. AURORA Stochastic Risk Model
8. PLEXOS Flexibility Analysis Model
9. Avoided Costs
10. Incremental Costs of Renewable Resources

Appendix I: Electric Analysis Inputs and Results

1. Introduction
2. Modeling Inputs
3. Modeling Outputs

Appendix J: Economic, Health and Environmental Assessment of Current Conditions

1. Introduction
2. Named Communities
3. Customer Benefit Indicators

Appendix K: Delivery System Planning

1. Introduction
2. Electric Projects in Implementation Phase
3. Electric Projects in Initiation Phase

Appendix L: Resource Adequacy

1. Introduction
2. Resource Adequacy Overview
3. Resource Adequacy Inputs and Updates
4. Resource Adequacy Modeling Approach
5. Detailed Results for Generic Resources
6. Comparison with the 2021 Integrated Resource Plan
7. Western Resource Adequacy Program Methodology

PUBLIC PARTICIPATION
APPENDIX A

PUGET SOUND ENERGY

Contents

1. Introduction 1

2. Public Participation Approach 1

2.1. Techniques and Objectives 2

3. Participants 4

4. Feedback Themes 6

4.1. Resource Alternatives and Emerging Technologies 6

4.2. Impacts of the Inflation Reduction Act 6

4.3. Clean Energy Transformation Act Compliance 6

4.4. Climate Change Considerations 7

4.5. Public Participation Process 7

5. Timeline, Meetings, and Topics 7

5.1. January 2022 7

5.2. February 2022 8

5.3. March 2022 8

5.4. April 2022 9

5.5. May 2022 9

5.6. June 2022 9

5.7. July 2022 10

5.8. August 2022 10

5.9. September 2022 11

5.10. October 2022 11

5.11. November 2022 12

5.12. December 2022 12

5.13. January 2023 12

5.14. February 2023 13

5.15. March 2023 13

6. Meeting Documentation 13

6.1. January 20, 2022 Webinar 13

6.2. March 22, 2022 Webinar 13

6.3. June 6, 2022 Webinar 14

6.4. July 12, 2022 Webinar 14

6.5. August 24, 2022 Webinar 14

6.6. September 13, 2022 Webinar 15

6.7. September 28 and 30, and October 25, 2022 Webinars 15

6.8. December 12, 2022 Webinar 15
6.9. March 14, 2023 Webinar 16

1. Introduction

Public participation is required and essential to developing Puget Sound Energy's 2023 Electric Progress Report (2023 Electric Report) for the 2021 Integrated Resource Plan (IRP). Puget Sound Energy (PSE) continues to expand and evolve the ways 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 Electric Report analysis. 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 eleven public meetings in 2022 before filing the 2023 Electric Report 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

Public participation for the 2023 Electric Report is built 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 IRP and subsequent 2023 Electric Report. The IAP2 framework, and various public participation techniques, helped PSE 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.

For the 2023 Electric Report, all meetings were open to the public, and we encouraged all 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 members of 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 particular 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, PSE conducted brainstorming sessions weeks before every public meeting to develop clear objectives.

PSE's public participation practices prioritize transparency and accessibility. These practices include:

- Making comments from members of the public about the 2023 Electric Report 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 Electric Report available
- Making meeting summaries and materials from 2023 Electric Report 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 schedule of report public meetings and significant topics to be covered on the PSE website (pse.com/irp)
- Providing transcripts of the chat log from public meetings and enable 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 the 2023 Electric Report. 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

All webinars were recorded and posted 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 by PSE 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 the 2023 Electric Report.

2.1.8. Other Communication Tools

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

- Triangle Associates conducted phone interviews with interested members of the public before public engagement meetings to discuss key concerns and explore process improvements.
- 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 reminded interested parties about upcoming webinars and deadlines, and included summaries of public feedback and updates on the status of the report's development.

3. Participants

One hundred and thirty-five organizations and 251 unique individuals participated in the development of the 2023 Electric Report. The participating organizations are listed below.

1099 Energy

1890 & Co

Absaroka Energy LLC

Armada Power

Atlas Renewable Power

Auto Grid

Avangrid Renewables

Avista

BayWa r.e.

Beacon Energy

Bonneville Power Administration

Brightnight Power

Broad Reach Power

BV Power

C Power Energy Management

Cadmus Group

Capital Power

Cascade Natural Gas

Chelan PUD

City of Des Moines

City of Enumclaw

City of Issaquah

City of Kenmore

City of Lake Forest Park

City of Mercer Island

City of Olympia

City of Puolsbo

City of Redmond

City of Seattle

City of Tacoma

Clear Energy Brokerage

Climate Solutions

Con Edison Clean Energy Business

Convergent Energy + Power

Creative Renewable Solutions

DNV

Ease Engineers

Ecoplexus

Elemental Energy

Enel

Energy Analytics

Energy GPS

Energy Solutions

Eolian Energy

esVolta

Flex Charging

Fortis

Franklin Energy

Frontier

General Electric

Generac Power Systems

Glarus Group

Guidehouse Consulting

Hardy Energy Consulting

Hecate Energy

Hull Street Energy

IATC

IBEW

IBV Energy

Illume Advising

Innergex

Invenergy

Jera Americas

King County

KL Gates

Laborers Local 252

Lakeridge Resources

Lightsource BP

Lloyd Reed Consulting

Matrixes Corp.

Monolith Energy Consulting

Mitsubishi Power Americas

Monolith Energy

Nationwide Energy Partners

NextEra Energy Resources

Northwest Power and Conservation Council

Northwest Power and Conservation Council

Novis Renewables

NW Energy Coalition (NWEC)

NWGA

NW Natural

Obsidian Renewables, LLC

One Energy Renewables

Optimum Building Consultants

Oracle

Pacific Architects and Engineers (PAE)

Pacific Northwest Utilities Conference Committee (PNUCC)

Pasco Energy

PGN

Phil Jones Consulting

Pierce County

Plus Power

Potelco

Power Ex

Q Cells

R Plus Energy

Renewable Northwest

Rye Development

Sageston Ventures

Sapere Consulting

SBW Consulting

Scout Clean Energy

Sierra Club

Snohomish County

Solar Horizon

SPI

Storage Alliance

Strata Clean Energy

Stratagen Consulting

Sun2oPartners

Sunenergy Systems Inc

Tenaska

The Masthead Group

TransAlta

Triangle Associates

Tuusso Energy LLC

UA Local 32

Wartsila

Washington Solar Energy Industries Association (WASEIA)

Wattbridge

West Rock

Western Energy Board

Washington Power Pool

Washington Environmental Council

Washington State Department of Commerce

Washington State Office of the Attorney General, Office of the Attorney General Public Counsel Unit

Washington Utilities and Transportation Commission (UTC)

Western Power Pool

Western Solar

Williams Companies

WRSI

Zipcon

4. Feedback Themes

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

4.1. Resource Alternatives and Emerging Technologies

Throughout the reporting process, interested parties expressed a desire to see PSE model alternative energy and energy storage solutions. For this report, PSE modeled several of these technologies, including:

- Advanced nuclear (SMR)
- Biodiesel
- Green hydrogen
- Hybrid renewables and diverse energy storage

Many interested parties expressed their concerns with SMR inclusion in the draft portfolio, so PSE removed SMR modeling for the final 2023 Electric Report.

➔ Please see Appendix D: Generic Resource Alternatives and Chapter Eight: Electric Analysis for additional information about how PSE modeled resource alternatives.

4.2. Impacts of the Inflation Reduction Act

Interested parties asked PSE to take into full consideration the impacts of the Inflation Reduction Act (IRA) in the 2023 Electric Report. PSE included the IRA provision for distributed solar investment tax credits (ITC) in the 2023 Electric Report because these are clear provisions that PSE has used in the past. However, the rulemaking process for energy efficiency is largely incomplete and we do not expect to understand the nuances of those results until mid-2023. PSE is working to stay informed about the IRA rulemaking process and will incorporate those provisions in future IRP cycles.

➔ Please see Chapter Four: Legislative and Policy Change for additional information about how PSE incorporated impacts of the IRA into this report.

4.3. Clean Energy Transformation Act Compliance

Interested parties expressed concern about PSE's commitment to compliance with the Clean Energy Transformation Act (CETA), which requires 100 percent GHG neutrality by 2030. PSE is pursuing cost-effective, reliable, and available conservation through renewable and non-emitting resources and we are committed to achieving the 2030 CETA requirements, as outlined in our 2021 Clean Energy Implementation Plan (CEIP). For the 2023 report, we focused on unbundled renewable energy credits (RECs) and carbon offsets to work toward meeting 100 percent GHG neutrality.

➔ Please see Chapter Eight: Electric Analysis and Chapter Two: Clean Energy Action Plan for additional information about CETA compliance in this report

4.4. Climate Change Considerations

Before and during this IRP cycle, members of the public 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 the 2023 Electric Report.

➔ Please see Appendix F: Demand Forecasting Models for additional information about how PSE incorporated climate change data into their planning process.

4.5. Public Participation Process

Participants involved in public meetings for the 2023 Electric Report gave us valuable feedback on improving the public participation and feedback process. We implemented real-time improvements during this cycle and are assessing the public participation process for the next IRP cycle. For additional details see Section 2.2 of this document.

5. Timeline, Meetings, and Topics

We conducted all public meetings for the 2023 Electric Report remotely to help prevent the spread of COVID-19 while improving access for members of the public. Each meeting began with an orientation that explained how to participate using the electronic platform. The Meeting Documentation section of this appendix provides links to documentation for each of the 11 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 individuals 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

Date	Description
	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 public input.
January 20	**Energy Planning Process and Next Steps for 2022 Webinar** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 135 participants Puget Sound Energy provided updates on the CEIP, and work plan for the 2023 report, explained climate change in load forecasting, and explained how the Conservation Potential Assessment (CPA) fits into the IRP. Participants 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 18	Invitation emailed to an expanded list of approximately 1,500 individuals for the March 22, 2022, Climate Commitment Act and assumptions for the 2023 Electric Progress Report webinar.
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.

5.3. March 2022

Date	Description
March 4	Invitation for March 22 Climate Commitment Act and assumptions for the 2023 Electric Progress Report webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including Climate Commitment Act, carbon prices and social cost of greenhouse gases, alternative electric supply-side resources and cost, and regional assumptions for electric price forecasts. 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 15	Meeting materials for March 22 webinar were posted to pse.com/irp, and a feedback form was opened.
March 22	**Climate Commitment Act and Assumptions for the 2023 Electric Progress Report Webinar** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 68 participants

Date	Description
	Puget Sound Energy presented information on the Climate Commitment Act, carbon prices and social Cost of Greenhouse Gases, alternative electric supply-side resources and cost, and regional assumptions for electric price forecasts.
March 24	A recording of the March 22 webinar and the chat transcript was posted to pse.com/irp.
March 31	Feedback forms were due for March 22 webinar; eight individuals responded.

5.4. April 2022

Date	Description
April 22	A feedback report of comments collected from the feedback form for the March 22 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.

5.5. May 2022

Date	Description
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 includes saving the dates for all upcoming 2022 IRP meeting dates 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** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 77 participants The Transmission team 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 were posted to pse.com/irp.
July 5	Meeting materials for July 12 webinar were posted to pse.com/irp, and a feedback form was opened.
July 12	**Electric and Gas Demand Forecast Webinar** **Public role:** Inform and Consult **Meeting platform**: Zoom **Attendance:** 64 participants Puget Sound Energy 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.
July 20	Invitation for the August 24 *resource adequacy information session* webinar emailed to an expanded list of approximately 1,500 individuals with listed topics including overview and results to the Western Resource Adequacy Program (WRAP), 2022 Regional Forecast from Pacific Northwest Utilities Conference Committee (PNUCC), a summary of resource adequacy modeling results from E3, and PSE resource needs and market reliance. Registration link to the webinar is included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.
July 22	Feedback forms were 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. 17	Meeting materials for the August 24 webinar were posted to pse.com/irp, and a feedback form was opened.
Aug. 24	**Resource Adequacy Information Session Webinar** **Public role:** Inform **Meeting platform:** Zoom **Attendance**: 60 participants Representatives from the Western Resource Adequacy Program (WRAP) provided an overview of their program and metrics, the Pacific Northwest Utilities Conference Committee (PNUCC) provided a 2022 Regional Forecast, E3 shared a summary of resource adequacy modeling results, and PSE presented on resource needs and market reliance.
Aug. 26	August 24 webinar recording and chat posted to pse.com/irp.
Aug. 29	Invitation for September 13 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. 2	Feedback forms are due for the August 24 webinar; four individuals responded.
Sept. 6	Meeting materials for September 13 webinar were posted to pse.com/irp, and a feedback form was opened.
Sept. 13	**Conservation Potential Assessment (CPA) and assumptions for the 2023 Electric Progress Report** **Public role:** Inform and Consult **Meeting platform:** Zoom **Attendance:** 67 participants Puget Sound Energy presented Inflation Reduction Act impacts on the Electric Progress Report, resource alternatives, and how PSE is working towards 100 percent greenhouse gas neutrality by 2030, and Cadmus Group presented Conservation Potential Assessment results.
Sept. 15	September 13 webinar recording and chat posted to pse.com/irp.
Sept. 23	Feedback forms were due for September 13 webinar; four individuals responded
Sept. 28	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult **Meeting platform:** Zoom **Attendance:** 19 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.
Sept. 30	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult **Meeting platform:** Zoom **Attendance:** 16 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.

5.10. October 2022

Date	Description
Oct. 14	A feedback report of comments collected from the feedback form for the September 13 webinar, PSE's responses, and a meeting summary posted to pse.com/irp.
Oct. 20	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 Gas Utility IRP. Registration link to Webinar was included, and a sign-up or opt-out option for notifications concerning the process.
Oct. 25	**Portfolio Benefits Analysis Drop-In Session** **Public role:** Consult

Date	Description
	Meeting platform: Zoom **Attendance:** 14 participants Puget Sound Energy presented potential methodology for utilizing customer benefits in portfolio analysis, discussed potential methodology and ways to improve or evolve it, and discussed next steps for use of the analysis.

5.11. November 2022

Date	Description
	Feedback forms were due for September 28, 30, and October 25 drop-in sessions; 4 individuals responded.
Nov. 16	Invitation for December 12 *Updates and feedback on draft results of electric and gas portfolio* webinar emailed to an expanded list of 1,500 individuals with listed topics, including final draft results for electric and gas portfolio. Registration link to the webinar is included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.
Nov. 22	A feedback report of comments collected from the feedback form for the September 28 and 30, and October 25 drop-in sessions, along with PSE's responses and a meeting summary posted to pse.com/irp.

5.12. December 2022

Date	Description
Dec. 5	Meeting materials for December 12 webinar were posted to pse.com/irp, and a feedback form was opened.
Dec. 12	**Draft results of electric portfolios webinar** **Public role**: Consult, Involve and Inform **Attendance:** 92 participants Puget Sound Energy delivered an overview of the 2023 Electric Progress Report modeling process and timeline; discussed PSE's distributed energy resources and customer renewable programs; presented resource plan modeling results; and facilitated a discussion of the candidate portfolios.
Dec. 14	December 12 webinar recording and chat posted to pse.com/irp.
Dec. 19	Feedback forms were due for the December 12 webinar; 4 individuals responded.

5.13. January 2023

Date	Description
Jan. 9	A meeting summary for the December 12 meeting posted to pse.com/irp.
Jan. 24	Draft Chapter 3: Resource Plan of the Electric Progress Report published at pse.com/irp. A feedback form was opened.

5.14. February 2023

Date	Description
Feb. 7	Feedback forms due for the Draft Chapter 3: Resource Plan of the Electric Progress Report published at pse.com/irp.
Feb. 27	Invitation for March 14 *Final portfolio results of 2023 Electric Progress Report and Gas Utility IRP* webinar emailed to the expanded list of approximately 1,500 individuals with listed topics, including final results for electric and gas portfolio. Registration links to both Webinars are included, and a sign-up or opt-out option for notifications concerning the process. Registration links and information are also posted online.

5.15. March 2023

Date	Description
March 7	Meeting materials for March 14 webinar were posted to pse.com/irp.
March 14	**Final Portfolio results of the 2023 Electric Progress Report and Gas Utility IRP Webinar** **Public role:** Inform and Consult **Attendance:** TBD In this webinar, PSE explained the market risk assessment and results of the stochastic analysis. The preferred portfolio and background concerning the approach and methodology was presented.
March 16	March 14 webinar recording and chat posted to pse.com/irp.
March 24	March 14 webinar meeting summary 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 22, 2022 Webinar

Topic: Climate Commitment Act and assumptions for the 2023 Electric Progress Report

- Hot Sheet

- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report
- Meeting Files
    - 2023 Electric Progress Report – Generic Resource Cost Adjustments (Excel)
    - 2023 Electric Progress Report – Generic Resource Cost Breakdown (Excel)
    - 2023 Electric Progress Report – Regional New Builds and Retirements (Excel)
    - 2019 HDR Generic Resource Assumptions 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. August 24, 2022 Webinar

Topic: Resource adequacy information session

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

- Meeting summary and feedback report
- Meeting files:
    - August 2021 Effective Load Carrying Capability (ELCC) Workshop Recording
    - Presentation from the 2021 ELCC Workshop
    - Resource Adequacy Primer (2021)
    - Review of Puget Sound Energy ELCC Methodology (2021)
    - Response to Public Comments on ELCC Calculations and Use (2021)
    - Market Reliance Workshop presentation (2021)
    - Market Reliance Workshop video recording (2021)
    - Market Reliance Workshop Q&A (2021)

6.6. September 13, 2022 Webinar

Topic: Electric Progress Report: Final resource need and Conservation Potential Assessment (CPA) results

- Hot sheet
- Agenda
- Presentation
- Chat log
- Meeting recording
- Meeting summary and feedback report
- Meeting files:
    - Electric Price Forecast for the 2023 Electric Progress Report
    - 2023 Electric Progress Report Electric Price Forecast [Excel]
    - Generic Resources Capital Costs and Operating Assumptions
      2023 Electric Progress Report Updated Generic Resources Cost Assumptions [Excel]

6.7. September 28 and 30, and October 25, 2022 Webinars

Topic: Portfolio Benefits Analysis Drop-in Sessions

- Presentation
- Customer Benefit Indicator Calculator [Excel]
- Meeting summary and feedback report

6.8. December 12, 2022 Webinar

Topic: Draft portfolio results of 2023 Electric Progress Report

- Hot sheet
- Agenda
- Presentation

- Chat log
- Meeting recording
- Meeting summary

6.9. March 14, 2023 Webinar

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

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

LEGAL REQUIREMENT

APPENDIX B

PUGET SOUND ENERGY

Contents

1. Regulatory Requirements 1

2. Report on Previous Action Plans 10

2.1. Acquire Energy Efficiency 11

2.2. Equity Advisory Group 11

2.3. Mitigate Risk of Short-term Energy Market 11

2.4. Supply-Side Resources: Issue an All-source RFP 11

2.5. Demand-side Resources: Develop and Issue a Demand Response and Distributed Energy Resources RFP 12

2.6. Emission Reduction Strategy and Planning 12

1. Regulatory Requirements

This document outlines PSE's regulatory requirements for the 2023 Electric Progress Report (2023 Electric Report). Figure B.1 lists the regulatory requirements for electric utilities codified Washington Administrative Code (WAC) 480-100-620, 480-100-625 and 480-100-630. Figure B.2 lists requirements in the Revised Code of Washington (RCW) 19.280.030. Figure B.3 lists the requirements in RCW 19.280.100.

Table B.1: Electric Progress Report Regulatory Requirements Codified in WAC 480-100-620, 480-100-625, and 480-100-630

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620(3)(a) Assessments of a variety of distributed energy resources. These assessments must incorporate nonenergy costs and benefits.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan Decisions • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning
WAC 480-100-620(3)(b)(i) An assessment of currently employed and potential policies and programs needed to obtain all cost-effective conservation, efficiency and load management improvements.	• Chapter Eight: Electric Analysis • Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-620(3)(b)(ii) Assess currently employed and new policies and programs needed to obtain all cost-effective demand response.	• Chapter Three: Resource Plan Decisions • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning • Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-620(3)(b)(iii) Include distributed energy programs and mechanisms identified pertaining to energy assistance.	PSE provided an assessment to the Department of Commerce of mechanisms pertaining to energy assistance, as well as progress toward meeting customer energy assistance need. Existing PSE programs include bill assistance and weatherization services. Currently, PSE does not have any distributed energy resource (DER) programs as part of its energy assistance strategy. However, in future years, there may be programs and mechanisms that could be used to meet customer energy assistance need, and those programs will be considered and incorporated into the IRP as indicated in draft WAC 480-100-610(3).
WAC 480-100-620(3)(b)(iv)	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan

Statutory or Regulatory Requirement	Chapter and/or Appendix
Assess other distributed energy resources that may be installed by the utility or the utility's customers including energy storage, electric vehicles, and PV.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix K: Delivery Systems Planning
WAC 480-100-620(4) An assessment of a wide range of commercially available generating and nonconventional technologies.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(5) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources and addressing overgeneration events, if applicable to the utility's resource portfolio.	• Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(6) An assessment of regional generation and transmission capacity. Must include the utility's existing transmission capabilities, and future resource needs. Must identify the general location and extent of transfer capability limitations on its transmission network.	• Appendix K: Delivery Systems Planning
WAC 480-100-620(7) A comparative evaluation of all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost.	• Chapter Three: Resource Plan • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model • Appendix K: Delivery Systems Planning
WAC 480-100-620(8) An assessment and determination of resource adequacy metrics and an appropriate resource adequacy requirement and measurement metrics consistent with CETA.	• Chapter Seven: Resource Adequacy
WAC 480-100-620(9) An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk, informed by the cumulative impact analysis conducted by the department of health.	• Appendix J: Economic, Health and Environmental Assessment of Current Conditions
WAC 480-100-620(10)(a) At least one scenario must describe the lowest reasonable cost and reasonably available portfolio that the utility would	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model

Statutory or Regulatory Requirement	Chapter and/or Appendix
have implemented if not for CETA requirements in RCW 19.405.040 and 19.405.050.	
WAC 480-100-620(10)(b) At least one scenario must be a future climate change scenario.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(10)(c) At least one sensitivity must be a maximum customer benefit scenario. The sensitivity should model the maximum amount of customer benefits described in RCW 19.405.040(8).	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(11) Integration of the demand forecasts and resource evaluations into a long-range integrated resource plan describing the mix of resources that meet current and projected resource needs.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Six: Demand Forecasts • Appendix F: Demand Forecasting Models
WAC 480-100-620(11)(a) A narrative description of decisions made including how the IRP expects to achieve the clean energy transformation standards at lowest cost.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan
WAC 480-100-620(11)(b) A narrative description of decisions made including how the IRP expects to serve utility load, based on hourly data with the output of the utility's owned resources, market purchases, and power purchase agreements net of any off-system sales.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(c) A narrative description of decisions made including how the IRP expects to include all cost-effective, reliable and feasible conservation and efficiency and demand response resources.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(d) A narrative description of decisions made including how the IRP expects to consider acquisition of existing renewable resources.	• Chapter Two: Clean Energy Action Plan Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(e) A narrative description of decisions made including how the IRP expects in the acquisition of new resources, to rely on renewable resources and energy storage in so far as doing so is at the lowest reasonable cost.	• Chapter Two: Clean Energy Action Plan Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(f) A narrative description of decisions made including how the IRP expects to maintain and protect the safety, reliable operation, and balancing of the utility's electric system.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(g)	• Chapter Two: Clean Energy Action Plan

Statutory or Regulatory Requirement	Chapter and/or Appendix
A narrative description of decisions made including how the IRP expects to achieve the requirements in WAC 480-100-610 (4) (c) including the long-term strategy and interim steps the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations; and the estimated degree to which benefits will be equitably distributed and burdens reduced over the planning horizon.	
WAC 480-100-620(11)(h) A narrative description of decisions made including how the IRP expects to assess the environmental health impacts to highly impacted communities.	• Appendix J: Economic, Health and Environmental Assessment of Current Conditions
WAC 480-100-620(11)(i) A narrative description of decisions made including how the IRP expects to analyze and consider combinations of distributed energy resource costs, benefits, and operational characteristics to meet system needs.	• Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis
WAC 480-100-620(11)(j) A narrative description of decisions made including how the IRP expects to incorporate the social cost of greenhouse gas emissions as a cost adder.	• Appendix G: Electric Price Models Chapter Five: Key Analytical Assumptions
WAC 480-100-620(12) A ten-year clean energy action plan for implementing the clean energy standards at the lowest reasonable cost; informed by the utility's ten year cost-effective conservation potential assessment; identifies how the utility will meet the requirements in WAC 480-100-610 (4) (c); establishes a resource adequacy requirement; identifies cost-effective demand response and load management programs; identifies renewable resources, nonemitting electric generation and distributed energy resources; identifies any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities; identifies the nature and possible extent to which the utility will rely on alternative compliance options; and incorporates the social cost of greenhouse gas emissions as a cost adder.	• Chapter Two: Clean Energy Action Plan
WAC 480-100-620(13) Include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. Must list nonenergy costs and benefits addressed in the IRP and specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities or the general public.	• Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(14) Data input files made available to the Commission in native format as an appendix to the IRP.	• Appendix H: Electric Analysis and Portfolio Model

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-620(15) Information and analysis that will be used to inform annual filings under Chapter 480-106 WAC related to qualifying facilities.	• Appendix H: Electric Analysis and Portfolio Model
WAC 480-100-620(16) A summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the previous IRP.	• Chapter Five: Key Analytical Assumptions
WAC 480-100-620(17) A summary of public comments received during IRP development and utility responses.	• Appendix A: Public Participation
WAC 480-100-625(4)(a)(i) In this report, the utility must update its load forecast.	• Chapter Six: Demand Forecast
WAC 480-100-625(4)(a)(ii) In this report, the utility must update its demand-side resource assessment, including a new conservation potential assessment.	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-625(4)(a)(iii) In this report, the utility must update its resource costs.	• Chapter Five: Key assumptions • Appendix D: Generic Resource Alternatives
WAC 480-100-625(4)(a)(iv) In this report, the utility must update its portfolio analysis and preferred portfolio.	• Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Models
WAC 480-100-625(4)(b)(v) The progress report must include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces.	• Chapter Four: Legislative and Policy Change
WAC 480-100-625(4)(c) The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.	• Chapter 4: Legislative and Policy Change • Chapter 8: Electric Analysis
WAC 480-100-630(1) The utility must demonstrate and document how it considered input from advisory group members in the development of its IRP and two-year progress report. Examples of how the utility may incorporate advisory group input including using modeling scenarios, sensitivities, and assumptions advisory group members proposed and using data and information supplied by advisory group members as inputs to plan development.	• Chapter One: Executive Summary • Appendix A: Public Participation

Table B.2: Electric Utility Integrated Resource Plan Regulatory Requirements Codified in RCW 19.280.030

Statutory or Regulatory Requirement	**Chapter and/or Appendix**
RCW 19.280.030(1)(b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as	• Chapter Eight: Electric Analysis

PSE PUGET SOUND ENERGY

Statutory or Regulatory Requirement	Chapter and/or Appendix
appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources.	• Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources.	• Chapter Four: Legislative and Policy Change • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion.	• Chapter Three: Resource Plan • Chapter Five: Key Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix E: Conservation Potential Assessment and Demand Response Assessment • Appendix H: Electric Analysis and Portfolio Model Appendix K: Delivery System Planning
RCW 19.280.030(1)(e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix D: Generic Resource Alternatives • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(f) An assessment and ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers.	• Chapter Three: Resource Plan • Chapter Five: Key Assumptions • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis
RCW 19.280.030(1)(g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts.	• Chapter One: Executive Summary • Chapter Seven: Resource Adequacy • Chapter Eight: Electric Analysis • Appendix G: Electric Price Models • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.030(1)(h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations.	• Chapter Five: Key Analytical Assumptions • Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.030(1)(i)	• Chapter Seven: Resource Adequacy

Statutory or Regulatory Requirement	Chapter and/or Appendix
An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing sections 3 through 5 of CETA.	• Chapter Eight: Electric Analysis • Appendix G: Electric Price Models
RCW 19.280.030(1)(j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing sections 3 through 5 of CETA, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliability operation, and balancing of its electric system.	• Chapter One: Executive Summary • Chapter Two: Clean Energy Action Plan • Chapter Three: Resource Plan • Chapter Five: Key Analytical Assumptions
RCW 19.280.030(1)(k) An assessment, informed by the cumulative impact analysis conducted under section 24 of CETA of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks, and energy security and risk.	• Chapter Two: Clean Energy Action Plan • Appendix J: Economic, Health and Environmental Assessment of Current Conditions
RCW 19.280.030 (1) (l) A ten-year clean energy action plan for implementing sections 3 through 5 of CETA at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.	• Chapter Two: Clean Energy Action Plan
RCW 19.208.030(3)(a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities, pursuant to section 15 of CETA when developing integrated resource plans and clean energy action plans.	• Chapter Five: Key Analytical Assumptions • Chapter Eight: Electric Analysis • Appendix H: Electric Analysis and Portfolio Model

Table B.3: Distributed Energy Resources Planning Requirements Codified in RCW 19.280.100

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.100(2)(a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery Systems Planning
RCW 19.280.100(2)(b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery Systems Planning
RCW 19.280.100(2)(c)	• Chapter Five: Key Analytical Assumptions

Statutory or Regulatory Requirement	Chapter and/or Appendix
Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	• Appendix E: Conservation Potential and Demand Response Assessments • Appendix H: Electric Analysis and Portfolio Model
RCW 19.280.100(2)(d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.100(2)(e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	• Chapter Four: Legislative and Policy Change • Appendix A: Public Participation • Appendix K: Delivery System Planning
RCW 19.280.100(2)(f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources	• Chapter Two: Clean Energy Action Plan • Chapter Five: Key Analytical Assumptions • Appendix K: Delivery System Planning

Statutory or Regulatory Requirement	Chapter and/or Appendix
to displace or delay system resources in the integrated resource plan;	
RCW 19.280.100(2)(g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery System Planning
RCW 19.280.100(2)(a) Identify the data gaps that impede a robust planning process as well as any upgrades, such as but not limited to advanced metering and grid monitoring equipment, enhanced planning simulation tools, and potential cooperative efforts with other utilities in developing tools needed to obtain data that would allow the electric utility to quantify the locational and temporal value of resources on the distribution system;	• Chapter Two: Clean Energy Action Plan
RCW 19.280.100(2)(b) Propose monitoring, control, and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers;	• Chapter Two: Clean Energy Action Plan
RCW 19.280.100(2)(c) Identify potential programs that are cost-effective and tariffs to fairly compensate customers for the actual monetizable value of their distributed energy resources, including benefits and any related implementation and integration costs of distributed energy resources, and enable their optimal usage while also ensuring reliability of electricity service, such as programs benefiting low-income customers;	Programs will be identified through the CEIP process and through engagement with the Equity Advisory Group. PSE is pursuing an Alternative Pricing pilot.
RCW 19.280.100(2)(d) Forecast, using probabilistic models if available, the growth of distributed energy resources on the utility's distribution system;	• Appendix E: Conservation Potential Assessment and Demand Response Assessment
RCW 19.280.100(2)(e) Provide, at a minimum, a ten-year plan for distribution system investments and an analysis of nonwires alternatives for major transmission and distribution investments as deemed necessary by the governing body, in the case of a consumer-owned utility, or the commission, in the case of an investor-owned utility. This plan should include a process whereby near-term assumptions, any pilots or procurements initiated in accordance with subsection (3) of this section or data gathered via current market research into a similar type of utility or other cost/benefit studies, regularly inform and adjust the long-term projections of the plan. The goal of the plan should be to provide the most affordable investments for all customers and avoid reactive expenditures to accommodate unanticipated growth in distributed energy resources. An analysis that fairly considers wire-based and nonwires	• Chapter Four: Legislative and Policy Change • Appendix A: Public Participation

Statutory or Regulatory Requirement	Chapter and/or Appendix
alternatives on equal terms is foundational to achieving this goal. The electric utility should be financially indifferent to the technology that is used to meet a particular resource need. The distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. The electric utility must identify in the plan the sources of information it relied upon, including peer-reviewed science. Any cost-benefit analysis conducted as part of the plan must also include at least one pessimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively high probable costs and comparatively low probable benefits, and at least one optimistic scenario constructed from reasonable assumptions and modeling choices that would produce comparatively low probable costs and comparatively high probable benefits;	
RCW 19.280.100(2)(f) Include the distributed energy resources identified in the plan in the electric utility's integrated resource plan developed under this chapter. Distribution system plans should be used as inputs to the integrated resource planning process. Distributed energy resources may be used to meet system needs when they are not needed to meet a local distribution need. Including select distributed energy resources in the integrated resource planning process allows those resources to displace or delay system resources in the integrated resource plan;	• Chapter Two: Clean Energy Action Plan • Chapter Five: Key Analytical Assumptions • Appendix K: Delivery System Planning
RCW 19.280.100(2)(g) Include a high level discussion of how the electric utility is adapting cybersecurity and data privacy practices to the changing distribution system and the internet of things, including an assessment of the costs associated with ensuring customer privacy; and	• Chapter Two: Clean Energy Action Plan • Appendix K: Delivery System Planning
RCW 19.280.100(2)(h) Include a discussion of lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.	• Appendix K: Delivery System Planning

2. Report on Previous Action Plans

Per WAC 480-100-238(3)(h),[1] each item from the 2021 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

[1] WAC 480-100-238

2.1. Acquire Energy Efficiency

Develop two-year targets and implement reliable programs that put PSE on a path to achieve an additional 53.4 aMW of energy efficiency by the end of 2023 through program savings.

Under the Energy Independence Act (EIA), Utilities must pursue all conservation that is cost-effective, reliable and feasible. They need to identify the conservation potential over a 10-year period and set two-year targets. This 10-year cost-effective savings of 266 aMW divided by 5 is called the pro-rata share, so PSE's draft 2021 EIA target for the 2022-2023 biennium is the 10- year pro-rata share, which is 53.4 aMW. If we were to look at just the 2-year savings from the cost-effective energy efficiency instead of the 10-year pro-rata share, the 2-year energy efficiency saving is only 41.7 aMW.

Progress: Through the end of 2022, PSE acquired 243.22 MWh of conservation, equal to 27.8 aMW or 48.8 percent of the target.

2.2. Equity Advisory Group

Convene and engage an Equity Advisory Group (EAG) to provide guidance from a diversity of voices in the development of PSE's short-term and long-term strategies, initiatives and programs to ensure the equitable distribution of benefits and reduction of burdens to highly impacted communities and vulnerable populations in the transition to clean energy.

Progress: PSE formed the EAG in April 2021, meeting 19 times between April 2021 and December 2022. The EAG has informed our work on a wide range of topics, including those listed above.

2.3. Mitigate Risk of Short-term Energy Market

Update internal policies for market transaction limits for PSE's Energy Supply Merchant and begin to secure firm resource adequacy qualifying capacity contracts to reduce the risk associated with short-term bilateral energy market purchases.

Progress: For the 2023 Electric Report, PSE assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm

2.4. Supply-Side Resources: Issue an All-source RFP

Determine and execute the appropriate resource acquisition strategy to meet the 2021 IRP resource needs with CETA-complaint resources. Ensure that all resources are evaluated across a consistent set of criteria and that appropriate enabling technologies sufficiently address the requirements necessary to support both distributed energy and utility-scale renewable resources.

Progress: On June 30, 2021, Puget Sound Energy (PSE) filed with the Washington Utilities and Transportation Commission (Commission) the final Request for Proposals for All Resources (the All-Source RFP) in docket UE-210220.

A draft All Source RFP was filed on April 1, 2020. After a 45-day public comment period, on June 1, 2021, PSE filed responses to all public comments and a revised RFP for Commission approval. Following an open meeting on June 11, 2021, the Commission issued Order #1 on June 14, 2021 approving with conditions PSE's draft All Source RFP. The Commission order approving PSE's All Source RFP may found in Commission's web site in the All-Source RFP docket UE-210220. Information about the Commission's approval process and how interested parties can participate can be found in the All-Source RFP Schedule and Public Participation sections below.

The All-Source RFP seeks bids from qualified respondents to supply up to 1,669 GWh of Clean Energy Transformation Act ("CETA") eligible resources and up to 1,506 MW of capacity resources to PSE. It is an All-Source RFP, meaning that PSE will consider any electric resource or energy storage resource that can meet all or part of the company's resource need, consistent with the requirements described in the RFP.

2.5. Demand-side Resources: Develop and Issue a Demand Response and Distributed Energy Resources RFP

File a targeted RFP with the Washington Utilities and Transportation Commission no later than November 15, 2021 for both distributed energy resources and demand response resources. Additional specific actions for the next four years will be developed and communicated in the CEIP. The electric action plan is discussed in further detail in Chapter 2, Clean Energy Action Plan

Progress: After filing a draft with the Washington Utilities and Transportation Commission ("WUTC") on April 1, 2021, and a subsequent public comment period, on May 14, 2021, PSE issued a RFI for DERs. The DER RFI enhanced PSE's understanding of DER options available in its service territory and informed the development of a well-designed targeted DER RFP. In 2021, PSE also developed the requirements for a virtual power plant ("VPP") platform that will be used to dispatch DERs, including demand response. PSE expects that a common VPP platform will provide additional value to PSE customers and clarity to DER bidders by identifying specific integration and operational requirements.

Using the knowledge gained through the RFI process, PSE filed the draft targeted DER RFP with the WUTC on November 15, 2021, in docket UE-210878, which incorporates the technical and operational requirements of the VPP platform. A revised DER RFP was filed on January 14, 2022, incorporating public comments, with the WUTC approving the updated filing on January 27, 2022. The final DER RFP was filed February 7, 2022. PSE accepted proposals for the DER RFP from February 7, 2022 till 11:59 PM PST on March 21, 2022.

2.6. Emission Reduction Strategy and Planning

Explore potential and voluntary carbon reduction opportunities, and develop and evaluate associated strategies for implementation. Bring the electric and natural gas modeling processes into closer alignment to improve the evaluation of future fuel use for power and the gas-to-electric end-use conversions. Explore the potential for the blending of clean fuels (hydrogen) with existing pipeline infrastructure and customer end use applications. Investigate a range of appliances that may assist with both reducing carbon and helping to ensure natural gas and electric system reliability on peak load days.

Progress: Puget Sound Energy continues to improve the process between the electric and gas utility modeling. For this progress report, we included modeling of hydrogen and natural gas blending starting in 2030 and increasing to 100 percent hydrogen by 2045. This fuel blending was modeled as options for new peaker plants along with the existing thermal plants. The 2023 Gas Utility IRP includes analysis for electrification and is located here.

➔ A full discussion of the hydrogen modeling is included in Chapter Five: Key Analytical Assumptions.

EXISTING RESOURCE INVENTORY

APPENDIX C

PUGET SOUND ENERGY

Contents

1. Introduction 1

1.1. Capacity Values 1

1.2. CETA-qualifying Capacity 1

2. Supply-side Resources 3

2.1. Renewable Resources 6

2.2. Thermal Resources 10

2.3. Long-term Contracts 13

2.4. Transmission Contracts 18

3. Demand-side Resources 20

3.1. Demand-side Resource Programs 20

3.2. Customer Renewable Energy Programs 25

1. Introduction

Puget Sound Energy (PSE) uses supply-side and demand-side resources to meet customer loads. Supply-side resources provide electricity to meet the load; these resources originate on the utility side of the meter. Demand-side resources contribute to meeting the need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. This appendix describes PSE's existing electric supply- and demand-side resources.

1.1. Capacity Values

We describe PSE's existing electric resources using the net maximum capacity of each generation facility in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period — in this case, 60 minutes — when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads, and before the losses incurred in transmitting energy over transmission and distribution lines. This explanation is consistent with how we described capacities in the annual 10K report[1] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

We referenced different capacity values in other PSE publications because output varies depending on a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades, and expansions. Selecting a single reference point based on a consistent set of assumptions is necessary to describe the relative size of resources. Depending on the nature and timing of the discussion, these assumptions, and therefore the expected capacity value, may vary.

1.2. CETA-qualifying Capacity

The Clean Energy Transformation Act (CETA) requires PSE to supply electricity free of greenhouse gas emissions by 2045; we must generate all electricity from renewable or non-emitting resources. PSE's total existing CETA-qualifying capacity is 2,969 MW, which includes 1,020 MW of PSE-owned and 1,465 MW of contracted resources. The final 483 MW of CETA-qualifying capacity are load-reducing contracted resources.

The following tables summarize PSE's existing supply-side resources, in MW of net maximum capacity, that meet CETA's renewable or non-emitting requirements. Additional details on these resources are in subsequent sections of this appendix.

Table C.1 presents all CETA-qualifying PSE-owned resources.

Table C.1: Existing PSE-owned CETA-qualifying Electric Generating Resources

Resource	Type	Net Maximum Capacity (MW)
Upper Baker River	Hydroelectric	91
Lower Baker River	Hydroelectric	105

[1] PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in February 2022 for the year ending December 31, 2021. See http://www.pugetenergy.com/pages/filings.html.

Resource	Type	Net Maximum Capacity (MW)
Snoqualmie Falls	Hydroelectric	48
Hopkins Ridge	Wind	157
Wild Horse	Wind	343
Lower Snake River	Wind	273
Wild Horse	Solar	0.5
Glacier Battery Demonstration Project	Storage	2
Total Capacity, PSE-owned	**All**	**1,020**

The majority of our CETA-qualifying energy is generated from contracted hydroelectric and wind resources. These are presented in Table C.2.

Table C.2: Existing Contracted CETA-qualifying Electric Generating Resources

Resource	Type	Net Maximum Capacity (MW)
Priest Rapids	Hydroelectric	6
Rock Island I & II	Hydroelectric	156
Rocky Reach	Hydroelectric	325
Wanapum	Hydroelectric	7
Wells	Hydroelectric	228
Canadian Entitlement Return	Hydroelectric	-33
Baker Replacement	Hydroelectric	7
Energy Keepers	Hydroelectric	40
BPA Capacity Product	Hydroelectric	100
Klondike III	Wind	50
Golden Hills	Wind	200
Clearwater	Wind	350
SPI Biomass	Biofuel/Biogas	17
Farm Power Rexville	Biofuel/Biogas	0.75
Rainier Biogas	Biofuel/Biogas	1
Vander Haak Dairy	Biofuel/Biogas	0.60
Edaleen Dairy	Biofuel/Biogas	0.75
Blocks Evergreen Dairy	Biofuel/Biogas	0.19
Emerald City Renewables	Biofuel/Biogas	4.5
Emerald City Renewables 2	Biofuel/Biogas	4.5
Total Capacity, Contracted Resources	**All**	**1,465**

Table C.3 details the existing resources allocated to serving PSE's customer renewable energy programs. We describe these programs in Section 3.2 of this appendix.

Table C.3: Existing CETA-qualifying Load Reducing Customer Program Electric Resources

Resource	Customer Program[2]	Type	Net Maximum Capacity (MW)
City of Bonney Lake	Community Solar	Solar	0.45
Olympia High School	Community Solar	Solar	0.2
Pine Lake Middle School	Community Solar	Solar	0.175
Urtica Solar	Community Solar	Solar	5
Penstemon Solar	Community Solar	Solar	5
Lund Hill	Green Direct	Solar	150
Skookumchuck	Green Direct	Wind	137
Camas Solar	Green Power/PURPA QFs	Solar	5
Koma Kulshan	PURPA QFs	Hydroelectric	13
Twin Falls	PURPA QFs	Hydroelectric	20
Weeks Falls	PURPA QFs	Hydroelectric	4.6
Cascade Community Solar #1 and #2 (combined)	PURPA QFs	Solar	0.03
Finn Hill (Lake Wash SD)	PURPA QFs	Solar	0.36
IKEA	PURPA QFs	Solar	0.83
Port of Coupeville	PURPA QFs	Solar	0.08
3 Bar-G Wind	PURPA QFs	Wind	0.12
Knudson Wind	PURPA QFs	Wind	0.11
Swauk Wind	PURPA QFs	Wind	4.3
Net Metering[1]	Net Metering	--	137
Total Capacity, Load Reducing Resources		**All**	**483**

Notes:

1. Existing net metered customers are captured in the base demand forecast. Therefore we do not include this as a resource in our IRP or progress report modeling.
2. PURPA QFs are Public Utility Regulatory Policies Act of 1978 Qualifying Facilities; Community Solar, Green Direct, Green Power, and Net Metering customer programs are described in section 4.7 of this appendix.

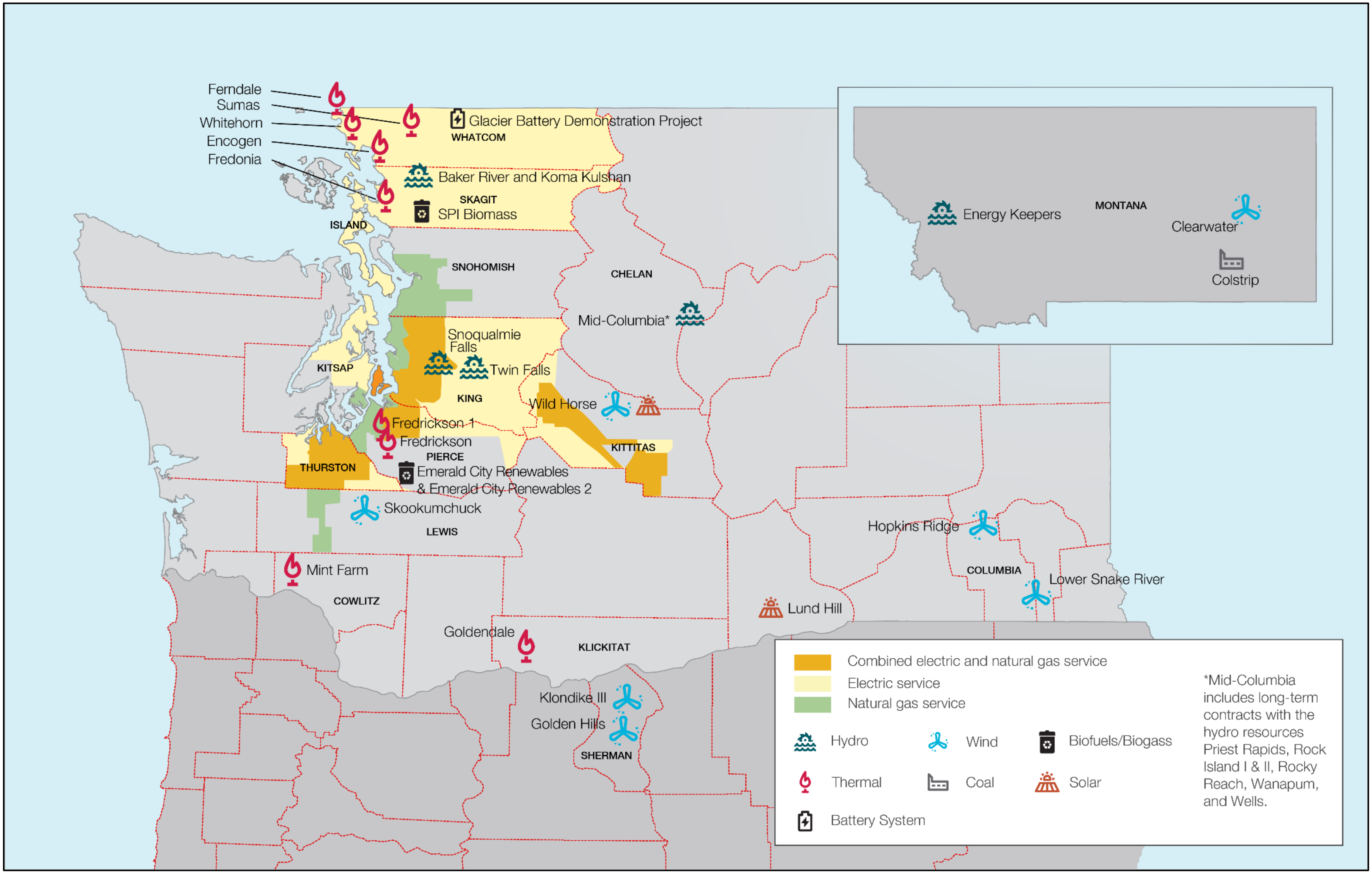
2. Supply-side Resources

We primarily use supply-side resources to meet customer load. We describe PSE's existing supply-side resources in the following sections and explain:

- **Generating and storage resources**: Hydroelectric, wind, solar, battery, coal, and combustion turbines (baseload and peakers)
- **Long-term contracts:** Negotiated with independent producers to supply electricity from various fuel sources
- **Transmission contracts:** Negotiated with Bonneville Power Administration (BPA) to carry electricity from the short-term wholesale market purchases to our service territory

Figure C.1 displays electricity-generating resources that PSE owns or contracts with independent energy producers. In this figure, we included only contracted projects with a maximum capacity greater than 5 MW. We show all PSE-owned facilities regardless of capacity.

Figure C.1: PSE's Existing Resources Inventory



2.1. Renewable Resources

Renewable resources use renewable fuels such as water, wind, sunlight, and biomass to generate electricity. Hydroelectricity generation provides flexible baseload energy production, which means it produces energy at a constant rate over long periods and is used to meet some or all a region's continuous energy demand. Hydroelectricity can also perform peaking functions when needed. Alternatively, wind and solar are intermittent resources – also known as variable energy resources – because their generating patterns vary due to uncontrollable environmental factors. These resources cannot consistently deliver energy when customers need it, such as when the wind dies down or clouds cover the sun, so we need additional energy sources to back up intermittent resources.

Hydroelectricity and wind generation are PSE's primary renewable resources. Utility-scale wind and solar are PSE's largest intermittent resources. Other intermittent resources include small-scale power production generated by customers, including rooftop solar.

Energy storage has the potential to provide multiple services to the PSE system, including backup power for intermittent renewable generation, efficiency, reliability, and ancillary services. Storage can benefit the entire system — generation, transmission, distribution, and customers. However, these benefits vary by location and how we apply the technology or resource. For instance, storage in one place could relieve transmission congestion and thereby defer the cost of transmission upgrades, while storage at another location might back up intermittent wind generation and reduce integration costs.

Puget Sound Energy's energy storage resources include hydroelectric reservoirs behind dams and oil backup for peaking facilities and batteries. Battery and pumped hydroelectric energy storage (PHES) operate for a limited time and require energy from other sources.

Table C.4 summarizes PSE's total renewable resources, and the subsections describe PSE's existing hydroelectricity, wind, and solar generating resources and PSE's storage facilities.

Table C.4: Total Renewable Resources

Type	Net Maximum Capacity (MW)
Hydroelectric — owned	244
Hydroelectric — contracted	722
Wind	773
Solar	0.5
Battery Storage	2.0
Total	1,742

2.1.1. Hydroelectricity

Puget Sound Energy's hydroelectric resources are precious clean energy sources that provide a net maximum capacity of 966 MW (Table C.3). These resources can instantly respond to customer load and have relatively low operating costs. Hydroelectric resources are limited operationally by protections for endangered species and environmental conditions. High precipitation and snowpack levels generally allow us to generate more hydroelectricity, and low-water years produce less hydroelectricity. During low-water years, we must rely on other, more expensive, self-generated power or market resources to meet the load. Our analysis for this 2023 Electric Progress Report (2023 Electric Report) accounts for both seasonality and year-to-year variations in hydroelectric generation. Puget Sound Energy owns hydroelectric projects in western Washington and has long-term power purchase contracts with three public utility districts (PUDs) that own and operate extensive hydroelectric facilities on the Columbia River in central Washington. These resources are described in this section and summarized in Table C.5.

Table C.5: PSE-owned and Contracted Hydroelectric Resources

Plant	Owner	PSE Ownership (%)	NET Maximum Capacity (MW)[1]	Contract Expiration Date
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	105	None
Snoqualmie Falls[2]	PSE	100	48	None
Wells[3]	Douglas Co. PUD	27.1	228	9/30/28
Rocky Reach[4]	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II[4]	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.6	7	03/31/52
Priest Rapids	Grant Co. PUD	0.6	6	03/31/52
Total Owned	-	-	244	-
Total Contracted	-	-	722	-
Total All	-	-	966	-

Notes:

1. Net maximum capacity reflects PSE's share only.
2. The FERC license authorizes the full 54.4 MW. However, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 square cubic feet and, therefore, output to 47.7 MW.
3. In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that began on August 31, 2018, and continues through September 30, 2028. PSE also agreed in June 2018 to purchase an additional 5.5 percent of the Wells project through September 2021. This agreement for the additional 5.5 percent from the Wells project was extended through September 2025.
4. In 2021, PSE purchased an additional 5 percent share from 2022 through 2025.

Puget Sound Energy also contracts smaller hydroelectric generators in PSE's service territory. We discuss these hydroelectric resources in the Long-term Contracts section and provide summaries in Tables C.12 and C.13.

Baker River Hydroelectric Project

Baker River Hydroelectric project is in Washington's north Cascade Mountains. The facility comprises two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems, including a floating surface collector (FSC) to safely capture juvenile salmon in Baker Lake and transport them downstream around both dams. There is a second, newer FSC on Lake Shannon to move young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access to recreation and significant flood-control storage for people and property in the Skagit Valley.

Hydroelectric projects require a license from FERC for construction and operation. These licenses typically are for 30 to 50 years, and after that initial period, they must be renewed to continue operations. After a lengthy renewal process, FERC issued a 50-year license in October 2008, allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. Puget Sound Energy also completed a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The replacement unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.[2]

Snoqualmie Falls Hydroelectric Project

Located east of Seattle on the western slope of the Cascade Mountains, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, encased in bedrock 270 feet beneath the surface, was the world's first underground power plant. Built in 1898–99, Snoqualmie Falls Hydroelectric Project was also the Northwest's first large hydroelectric power plant.

The FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility underwent a significant redevelopment project between 2010 and 2015, which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment increased annual output by more than 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.[2]

Mid-Columbia Long-term Purchased Power Contracts

Under long-term power purchase agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects on the Columbia River in central Washington. Puget Sound Energy pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. In March 2017, PSE entered into a new power sales agreement with Douglas County PUD that began on August 31, 2018, and continues through September 30, 2028.

Under this new agreement, PSE will continue to take a percentage of the output from the Wells project. The actual rate available to PSE will be calculated annually and based primarily on Douglas PUD's retail load requirements. As Douglas PUD's retail load grows or declines, they will reserve a greater or lesser share of Wells project output for their customers, and the percentage we purchase will decrease or increase. Puget Sound Energy has a 20-year agreement with Chelan County PUD to purchase 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. Puget Sound Energy also has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD continues through the term of the project's FERC license, which ends on March 31, 2052.

2 RCW 19.285

2.1.2. Wind Energy

Puget Sound Energy is the largest utility owner and operator of wind power facilities in the Pacific Northwest. The maximum capacity of the company's three wind farms is 773 MW (Table C.6). The farms produce more than 2 million MWh of power per year on average, which is about eight percent of PSE's energy needs. These resources are integral to meeting renewable resource commitments.

- **Hopkins Ridge** in Columbia County, Washington, with an approximate maximum capacity of 157 MW, began commercial operation in November 2005.
- **Lower Snake River** in Garfield County, Washington, with an approximate maximum capacity of 343 MW, began operation in February 2012 and is PSE's third and largest wind farm.
- **Wild Horse** in Kittitas County near Ellensburg, Washington, with an approximate maximum capacity of 273 MW, began commercial operation in December 2006 at 229 MW and was expanded by 44 MW in 2010.

Table C.6: PSE-owned Wind Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Hopkins Ridge	100	157
Lower Snake River, Phase 1	100	343
Wild Horse	100	273
Total	100	773

2.1.3. Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[3] The array can produce up to 0.5 MW of electricity with full sun (Table C.6). Panels can also produce power under cloudy skies — 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine yearly, roughly the same as Houston, Texas. On average, this site generates 780 MWh of power per year.

In addition to the Wild Horse solar facility, we own three small solar facilities that provide energy for our Community Solar program, which is a customer renewable energy program described in Section 4.2. These facilities are located in western Washington on the roofs of public buildings, including schools and a municipal water storage facility. The first facility opened in November 2021.

Table C.7: PSE's Owned Solar Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Wild Horse Solar Demonstration Project	100	0.50
City of Bonney Lake	100	0.45
Olympia High School	100	0.20

[3] Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility and used 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Pine Lake Middle School	100	0.18
Total	100	1.33

2.1.4. Battery Energy Storage System

Puget Sound Energy's only battery energy storage system, the Glacier Battery Demonstration Project, was installed in early 2017 (Table C.8). The 2 MW / 4.4 MWh lithium-ion battery storage system is adjacent to the existing Glacier, Washington substation in Whatcom County. The Glacier project serves as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core island of businesses and residences during outages, reduces system load during periods of high demand, and helps balance energy supply and demand.

The project was partly funded by a $3.8 million Smart Grid Grant from the Washington State Department of Commerce. Between January and June of 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward successfully responding to unplanned outages.

We have two additional battery projects in the planning phases. The first project plans to install a 3.3 MW utility-scale battery as part of a larger project to improve reliability and modernize the grid on Bainbridge Island. The battery system will serve electricity during peak periods when customer demand is high (e.g., cold winter mornings), and we expect it to be online by the end of 2023. The second project plans to install a 1 MW lithium-ion battery at PSE's Blumaer substation and a solar array on adjacent land. Both installations will complement existing solar panels at nearby Tenino High School. The combined system will form a microgrid capable of providing temporary backup power to the school during an outage. Performance testing by PSE and PNNL is planned through 2024.

Table C.8: PSE-owned Battery Storage Resources

Unit	PSE Ownership (%)	Net Maximum Capacity (MW)
Glacier Battery Demonstration Project	100	2.0
Total	100	2.0

2.2. Thermal Resources

Thermal resources use fossil fuels (natural gas, oil, coal) or alternative fuels (biodiesel, hydrogen, renewable natural gas) to generate electricity. Puget Sound Energy's existing thermal resources include combustion turbines and coal-fired generating facilities, which serve as baseload or peaking resources.

Baseload resources produce energy at a constant rate over long periods at a lower cost than other production facilities available to the system. They are typically used to meet some or all a region's continuous energy demand. Baseload resources usually have a high fixed cost, but low marginal cost and are the most efficient thermal units PSE operates.

Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Peaking resources are quick-starting units that can ramp up and down quickly to meet short-term spikes in need. They also provide flexibility for load following wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload resources. Historically, peaking units have low-capacity factors because they are often not economical compared to market purchases.

Table C.9 summarizes, and the following subsections describe, PSE's thermal resources, which include combined-cycle combustion turbines (CCCTs), coal, and simple-cycle combustion turbines (CT peakers).

Table C.9: Total Thermal Resources

Type	Use	Net Maximum Capacity (MW)
CCCT	Baseload	1,293
Coal	Baseload	370
CT	Peaker	612
Total baseload thermal resources	-	1,663
Total CT peaking resources	-	612
Total thermal resources	-	2,275

2.2.1. Combined-cycle Combustion Turbines

Puget Sound Energy's six baseload CCCT plants have a combined net maximum capacity of 1,293 MW and are summarized in Table C.10. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy, making it more efficient than the CT peakers. Puget Sound Energy's baseload CCCTs include:

- **Encogen, Ferndale, and Sumas** in Whatcom County, Washington
- **Frederickson 1** in Pierce County, Washington. Puget Sound Energy owns 49.85 percent of this plant; Atlantic Power Corporation owns the remainder
- **Goldendale** in Klickitat County, Washington
- **Mint Farm** in Cowlitz County, Washington.

Table C.10: CCCT Resources by Facility

Name	PSE Ownership (%)	Net Maximum Capacity (MW)[1]
Encogen	100	165
Ferndale[2]	100	253
Frederickson 1[2,3]	49.85	136
Goldendale[2]	100	315
Mint Farm[2]	100	297
Sumas	100	127
Total	**-**	**1,293**

Notes:

1. Net maximum capacity reflects PSE's share only.
2. Maximum capacity of Ferndale, Frederickson 1, Goldendale, and Mint Farm includes duct firing capacity.

3. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation, USA.

The Colstrip Generating Plant Retirement and Shutdown Plan

After a request in June 2019 by PSE's Unit 1 and 2 co-owner and plant operator, Talen Montana LLC, PSE agreed to retire the units. We based our decision on economic considerations. In January 2020, the facility ceased to generate electricity and work commenced to place it in a secure and safe condition. We are currently overseeing environmental remediation of the impacted water and will continue, in compliance with all local, state, and federal regulations, as we retire the physical structures.

Units 3 and 4 are owned by six separate entities with different interests. Puget Sound Energy is limited in its ability to act unilaterally since operational decisions are dictated by the rules governing the ownership agreement. After 2025, CETA restricts PSE from serving load from Colstrip without penalty. As a result this EPR only includes generation from Colstrip 3 and 4 through 2025.

2.2.2. Coal

The Colstrip Generating Plant in eastern Montana, about 120 miles southeast of Billings, consists of four coal-fired steam electric plant units. Puget Sound Energy owns 25 percent each of Units 3 and 4 (Table C.11). Puget Sound Energy's ownership in Colstrip contributes 370 MW net maximum capacity to our existing portfolio.

Table C.11: Coal Resources by Facility

Name	PSE Ownership (%)	Net Maximum Capacity (MW)[1]
Colstrip 3 & 4	25	370
Total	**-**	**370**

Note: Net maximum capacity reflects PSE's share only.

2.2.3. Combustion Turbine Peakers

Combustion Turbine (CT) peakers provide important peaking capability and help PSE meet operating reserve requirements. We displace these resources when their energy is not needed to serve load or we can purchase lower-cost energy. Puget Sound Energy's three peaker plants (eight total units) contribute a net maximum capacity of 612 MW (Table C.12). When pipeline capacity is unavailable to supply them with natural gas fuel, these units can operate on distillate fuel oil.

- **Frederickson Units 1 and 2** are south of Seattle in east Pierce County, Washington.
- **Fredonia Units 1, 2, 3, and 4** are near Mount Vernon, Washington, in Skagit County.
- **Whitehorn Units 2 and 3** are in northwestern Whatcom County, Washington.

Table C.12: CT Peaking Resources

Name	PSE Ownership (%)	Net Maximum Capacity (MW)
Fredonia 1 & 2	100	207
Fredonia 3 & 4	100	107
Whitehorn 2 & 3	100	149
Frederickson 1 & 2	100	149
Total CT Peakers	**-**	**612**

2.3. Long-term Contracts

Long-term contracts include agreements with independent producers and utilities to supply electricity to PSE. Fuel sources for those contracts include hydropower, wind, solar, natural gas, coal, waste products, and system deliveries without a designated supply resource. We contract 1,882 MW of electric capacity, of which 58 percent (1,094 MW) is CETA-compliant. We did not include short-term wholesale market purchases negotiated by our energy trading group in this list.

2.3.1. Power Purchase Agreements

Most of PSE's long-term contracts are Power Purchase Agreements (PPAs) with independent power producers. This section provides a brief description of each PPA. Schedule 91 contracts define PPAs from small producers whose total capacity is 5 MW or less. We summarize these contracts in Table C.13 and Table C.14.

Table C.13: Power Purchase Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
BPA Capacity Product	Hydroelectric	1/1/2022	12/31/2026	100
Energy Keepers	Hydroelectric	3/1/2020	7/31/2035	40
Clearwater Wind	Wind	11/30/2022	11/29/2042	350
Golden Hills Wind	Wind	4/29/2022	4/28/2042	200
Klondike III	Wind	12/1/2007	11/30/2027	50
Skookumchuck Wind [1]	Wind	6/30/2020	12/31/2045	137
Lund Hill Solar [1]	Solar	12/1/2022	11/30/2042	150
SPI Biomass	Biomass	1/1/2021	12/31/2037	17
MSCG System	System	1/3/2022	12/31/2026	100
Pt. Roberts[2]	System	10/1/2022	9/30/2025	8
Coal Transition [3]	Coal	12/1/2014	12/31/2025	380
Total, CETA-compliant	-	-	-	**1,044**
Total	-	-	-	**1,532**

Notes:

1. Output from this resource serves subscribers to PSE's Green Direct program (Schedule 139 Contracts).
2. Point Roberts is not physically connected to PSE's system and relies on power from a single intertie point on BC Hydro's distribution grid.

3. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from Dec. 1, 2015, to Nov. 30, 2016, 380 MW from Dec. 1, 2016, to Dec. 31, 2024, and 300 MW from Jan. 1, 2025, to Dec. 31, 2025.

Table C.14: Schedule 91 Power Purchase Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
Black Creek	Hydroelectric	3/26/2021	12/31/2032	4.2
Koma Kulshan	Hydroelectric	12/1/1990	3/31/2037	13.3
Nooksack Hydro	Hydroelectric	1/1/2014	12/31/2023	3.5
Skookumchuck Hydro	Hydroelectric	2/25/2011	12/31/2025	1
Smith Creek	Hydroelectric	1/12/2011	12/31/2025	0.12
Sygitowicz – Kingdom Energy [1]	Hydroelectric	3/25/2016	12/31/2030	0.448
Twin Falls	Hydroelectric	12/1/1989	3/18/2025	20
Weeks Falls	Hydroelectric	12/1/1987	12/31/2023	4.6
3 Bar-G Wind [2]	Wind	8/31/2011	12/31/2029	0.12
Knudson Wind	Wind	6/16/2011	12/31/2029	0.108
Swauk Wind	Wind	12/14/2012	12/31/2023	4.25
Cascade Community Solar #1 and #2 (combined)	Solar	9/28/2012	12/31/2024	0.026
Finn Hill Solar (Lake Wash SD)	Solar	7/16/2012	12/31/2032	0.355
IKEA	Solar	1/1/2017	12/31/2031	0.828
Port of Coupeville [3]	Solar	1/1/2022	12/31/2023	0.075
Camas Solar	Solar	8/1/2018	12/31/2036	4.99
Penstemon Solar	Solar	1/1/2020	12/31/2036	4.99
Urtica Solar	Solar	8/1/2018	12/31/2036	4.99
Blocks Evergreen Dairy	Biogas	6/1/2017	12/31/2031	0.19
Edaleen Dairy	Biogas	8/21/2012	12/31/2023	0.75
Emerald City Renewables [4]	Biogas	11/6/2013	12/31/2029	4.5
Emerald City Renewables 2	Biogas	11/6/2013	12/31/2029	4.5
Farm Power Rexville	Biogas	8/28/2009	12/31/2032	0.75
Rainier Biogas	Biogas	11/30/2012	12/31/2032	1
VanderHaak Dairy [5]	Biogas	11/5/2004	12/31/2023	0.6
Total, CETA-compliant	-	-	-	**80**
Total	-	-	-	**80**

Notes:

1. The site was purchased by Hillside Clean Energy on May 1, 2020, with PSE's consent.
2. The agreement was initially for 1.395 MW, but only 0.120 MW was constructed; the contract was amended to reflect this change.

3. Formerly Island Solar, ownership was transferred to the Port of Coupeville on July 1, 2020, with PSE's consent.
4. Emerald City Renewables was formerly known as BioFuels Washington.
5. VanderHaak has two generators with a combined capacity of 0.60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of 0.45 MW.

Energy Keepers Hydroelectric

Puget Sound Energy contracted with Energy Keepers, Inc., a corporation owned by the Confederated Salish and Kootenai Tribes, to purchase 40 MW of zero-carbon energy produced by the Selis Ksanka Qlispe hydroelectric project through July of 2035.

Bonneville Power Administration Capacity Product Hydroelectric

Under a five-year agreement beginning in January 2022, the Bonneville Power Administration (BPA) will offer to sell PSE up to 100 MW of surplus power generated from the Federal Columbia River Power System. Hydroelectricity can quickly increase and decrease to meet power demand and help the region achieve its renewable goals by dovetailing with more variable output resources such as wind and solar.

Run-of-River Hydroelectric

Among our power purchase agreements are several long-term contracts for production output from hydroelectric projects within our balancing area. These contracts include Twin Falls, Koma Kulshan, and Weeks Falls. We show the contracts in Table C.13. The projects are run-of-river, meaning they do not hold back, store water, or provide flexible capacity.

Klondike III Wind

Puget Sound Energy's wind portfolio includes a power purchase agreement with Avangrid Renewables for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Oregon. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2027.

Golden Hills Wind

Puget Sound Energy executed a 20-year power purchase agreement with Avangrid Renewables for the output of a 200 MW wind farm they will build in Sherman County, Oregon. Avangrid expects to complete the project by mid-2022. The project will help us meet our goals to reduce greenhouse gas emissions and provide additional capacity to serve customers, particularly during winter periods of high electricity demand.

Clearwater Wind

Puget Sound Energy executed a 20-year power purchase agreement in early 2021 with NextEra Energy Resources to buy the output of 350 MW of wind-generated power. The wind farm is in Rosebud, Custer, and Garfield Counties, Montana, and began operation in November 2022. The project will allow PSE to use existing transmission lines from Colstrip, Montana, to bring energy to our customers in western Washington. This project also supports our environmental and deep decarbonization commitment by investing in more wind energy.

Skookumchuck Wind

Puget Sound Energy executed a 20-year power purchase agreement with Southern Power Company to purchase the output from the Skookumchuck Wind Project. The wind project is in Thurston and Lewis counties and became operational in November 2020. Along with the production from the Lund Hill Solar facility, the Skookumchuck facility output serves subscribers to our Green Direct program (Schedule 139), described in the Demand-side Resources section of this appendix.

Lund Hill Solar

Puget Sound Energy executed a 20-year power purchase agreement with Avangrid Renewables (through the project company Lund Hill Solar, LLC) to purchase the output from the Lund Hill Solar Project, located in Klickitat County, Washington. We expect the project to come online in late 2022. We will use the output from the facility to serve subscribers to PSE's new Green Direct program (Schedule 139), described in the Demand-Side Resources section of this appendix.

Sierra Pacific Industries Biomass

Puget Sound Energy has a 17-year contract with Sierra Pacific Industries (SPI) to purchase 17 MW of renewable energy from SPI's Mt. Vernon Mill; deliveries began in 2021. The cogeneration facility is an operational plant that uses wood byproducts from its manufacturing process to generate steam that makes electricity and heat kilns to dry lumber. An air pollution control device filters fine particles and other emissions from the burning wood.

Point Roberts System

This contract provides power deliveries to PSE's Point Roberts, Washington, retail customers. The Point Roberts load, physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for each MWh of energy delivered during the contract term.

Morgan Stanley Commodities Group System

Puget Sound Energy is in the Western System Power Pool (WSPP) agreement with the Morgan Stanley Commodities Group (MSCG) for a system PPA to deliver 100 MW of firm heavy load hour energy in the first and fourth quarters only, commencing in January 2022.

Coal Transition

Puget Sound Energy began purchasing 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024, the contract is for 380 MW; in the last year of the contract, 2025, the volume drops to 300 MW. This contract conforms to a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025.

In 2011, the State Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmental advocacy groups, and labor representatives. The timelines agreed to by the parties enable the state to transition to cleaner fuels while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

Schedule 91 Contracts

Puget Sound Energy's portfolio includes several electric power contracts with small power producers in our electric service area (see Table C.14). These qualifying facilities offer output pursuant to WAC chapter 480-106.[4] WAC 480-106-020 states: "A utility must purchase, in accordance with WAC 480-106-050 Rates for purchases from qualifying facilities, any energy and capacity that is made available from a qualifying facility: (a) Directly to the utility; or (b) Indirectly to the utility in accordance with subsection (4) of this section."[5] A qualifying facility is defined in WAC 480-106-007 as a "cogeneration facility or small power production facility that is a qualifying facility under 18 C.F.R. Part 292 Subpart B."[6]

2.3.2. Other Contract Agreements

In addition to PPAs, PSE has a long-term agreement with the U.S. Army Corps of Engineers (USACE), a treaty agreement between the U.S. and Canada, and a power exchange with Pacific Gas & Electric (PG&E). We describe these contracts in Table C.15 and the next section.

Table C.15: Other Contract Agreements for Electric Power Generation

Name	Type	Contract Start	Contract Expiration	Contract Capacity (MW)
Baker Replacement	Hydro	10/1/2019	9/30/2029	7
Canadian Entitlement Return	Hydro	1/1/2004	9/15/2024	-32.5
PG&E Seasonal Exchange — PSE	System	10/11/1991	Ongoing	300
Total, CETA-compliant	-	-	-	**-26**
Total	-	-	-	**275**

Baker Replacement

Under a 20-year agreement signed with the USACE, PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Upper Baker Reservoir at the request of the USACE. Then, during high precipitation and runoff between October 15 and March 1, PSE stores water in the Upper Baker Reservoir and controls its release to reduce downstream flooding. In return, PSE receives a total of 7,000 MWh of energy and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

[4] WAC 480-106
[5] WAC 480-106-020
[6] WAC 480-106-007

Canadian Entitlement Return

Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. We see benefits and obligations from this storage based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's obligation to return our share of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number. Puget Sound Energy's share of energy returned during 2021 was approximately 23 aMW, with a peak capacity return of 42.5 MW. The Columbia River Treaty has no end date but can be terminated after 2024 with 10 years' notice. The United States and Canada recently concluded the ninth round of negotiations to modernize the treaty to ensure effective flood risk management, provide a reliable and economical power supply, and improve the ecosystem.

Pacific Gas and Electric Seasonal Exchange

Under this system-delivery power exchange contract, PSE exchanges 300 MW of seasonal capacity and 413,000 MWh of energy with PG&E on a one-for-one basis each calendar year. Puget Sound Energy has historically been a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

2.4. Transmission Contracts

In addition to owning and purchasing power from electric generating resources, PSE fulfills loads by buying electricity from the short-term wholesale market. Puget Sound Energy participates in two markets. The first is the Mid-Columbia (Mid-C) market hub, the principal electricity market hub in the Northwest and one of the major trading hubs in the Western Electricity Coordinating Council (WECC). The Mid-C market hub is also the central market for northwest hydroelectric generation. The second is the Western Energy Imbalance Market (EIM), which allows participants to trade electricity in real-time across neighboring grids throughout the western United States. To carry this electricity to PSE's service territory, PSE has negotiated transmission contracts with BPA. This section describes these transmission contracts.

2.4.1. Mid-C Transmission

Puget Sound Energy has 2,481 MW of transmission capacity to the Mid-C market; of that, we contract 2,031 MW from BPA (Table C.16) long-term and own 450 MW (Table C.16).[7] Puget Sound Energy Merchant owns the BPA transmission rights. PSE Transmission sells 450 MW of transmission as the transmission provider. Currently, our 449 customers hold the rights to the 450 MW of transmission; however, when the 449 customers do not entirely utilize these rights, the rights are allocated to PSE Merchant or sold on the open access same-time information system

[7] PSE also owns transmission and transmission contracts to markets in addition to the Mid-C market transmission detailed here.

(OASIS). We use approximately 1,500 MW of this transmission capacity to the Mid-C wholesale market for short-term market purchases to meet our peak need.[8]

Table C.16: BPA Mid-C Hub Transmission Resources

Name	Effective Date	Termination Date	Transmission Demand (MW)
Midway	11/1/2017	11/1/2027	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach[1]	11/1/2017	11/1/2027	100
Rocky Reach	11/1/2017	11/1/2027	100
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	5
Rocky Reach	11/1/2019	11/1/2024	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2027	100
Vantage	12/1/2019	12/1/2024	169
Vantage	10/1/2013	3/1/2025	3
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	3
Vantage	11/1/2019	11/1/2024	36
Vantage	11/1/2019	11/1/2024	5
Wells	9/1/2018	9/1/2023	266
Vantage	3/1/2017	2/28/2026	23
Midway	10/1/2018	10/1/2023	115
Midway	3/1/2019	3/1/2024	35
Wells/Sickler	11/1/2018	11/1/2023	50
Vantage	11/1/2018	11/1/2023	50
Vantage	12/1/2019	11/1/2027	50
Total BPA Mid-C Transmission	**-**	**-**	**2,031**

Note: Contract split between Mid-C and EIM Imports below.

We own two transmission resources, described in Table C.17.

8 See Chapter Eight: Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Table C.17: PSE-Owned Mid-C Hub Transmission Resources

Name	Transmission Demand (MW)
McKenzie to Beverly	50
Rocky Reach to White River	400
Total PSE Mid-C Transmission	**450**

2.4.2. Energy Imbalance Market Transmission

When PSE joined the Energy Imbalance Market (EIM) in October 2016, we redirected 300 MW of Mid-C transmission capacity contracted from BPA annually for EIM imports. Starting in June 2020, Mid-C transmission shifted for EIM imports was reduced to 150 MW to align with PSE's market-based rate authority. This amount is required to maintain market-based authority and allows PSE to redirect beyond this amount for use in the EIM. Although these redirects reduce the transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. We will need to renew the amount of redirected Mid-C transmission on an ongoing basis, allowing us to reevaluate our EIM transfer capacity needs considering future winter peak needs. Table C.18 details the transmission capacity currently redirected for EIM.

We redirect an additional 300 MW, reserved under the PG&E Seasonal Exchange contract, for EIM exports during certain months of the year on an as-feasible basis. When our obligations to PG&E during summer months prevent this redirect, we instead redirect our existing Mid-C transmission, bringing the total redirected Mid-C transmission for EIM during summer months up to 450 MW.

Table C.18: Mid-C Hub Transmission Resources Redirected for EIM Imports as of 1/1/2023

Name	Effective Date	Termination Date	Transmission Demand (MW)
Rocky Reach	11/1/2017	11/1/2027	150
Total[1]	-	-	150

Note: Total BPA Mid-C Transmission Redirected for EIM Imports

3. Demand-side Resources

This section describes PSE's existing demand-side resources (DSR), which we implement on the customer side of the meter. The DSR programs include energy efficiency and demand response (DR) programs. We also describe the customer renewable energy programs PSE offers. In this 2023 Electric Report analysis, we account for the electricity contribution from DSR programs as a reduction in demand.

3.1. Demand-side Resource Programs

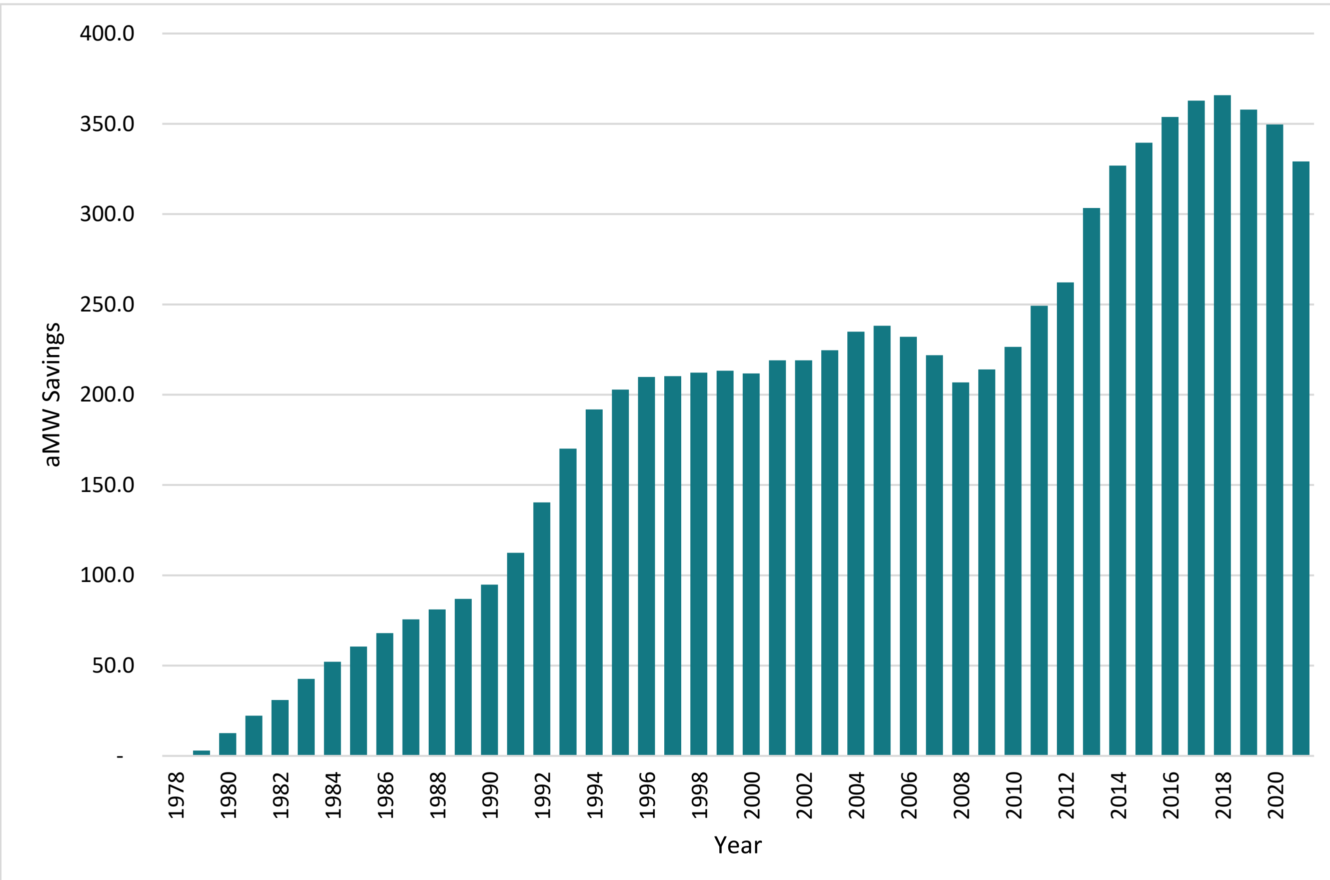
Puget Sound Energy's currently available DSR programs include the following:

- Demand Response
- Distributed Generation
- Distribution Efficiency

- Energy Efficiency
- Generation Efficiency

Puget Sound Energy has led the Pacific Northwest in implementing demand-side resource programs. Since 1978, our annual first-year savings (as reported at the customer meter) have grown by more than 200 percent, from 9 aMW in 1978 to 19.4 aMW in 2021 (Figure C.2). On a cumulative basis, these savings reached 329 aMW by 2021[9]. To achieve these savings, the company spent approximately $1.77 billion in incentives to customers and for program administration from 1978 to 2021.

Figure C.2: Cumulative Electric Energy Efficiency Savings from DSR, 1978–2021



3.1.1. Energy Efficiency

Energy efficiency is by far PSE's largest electric demand-side resource. Energy efficiency consists of measures and programs that replace existing building components and systems, such as lighting, heating, water heating, insulation, and appliances, with more energy-efficient versions. There are two types of measures: retrofit measures (when

[9] Savings are adjusted for measure life and then retired so they no longer count towards the cumulative savings. For the purposes of the PR analysis, measure life is assumed to be 10 years.

replacement is cost-effective before the equipment reaches its end of life); and lost opportunity measures (when replacement is not cost-effective until the existing equipment burns out).

Puget Sound Energy's energy efficiency programs serve all customers — residential (including low-income), commercial, and industrial. We establish program savings targets every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and the Integrated Resource Plan (IRP) public participation process. We fund most electric energy efficiency programs with electric conservation rider funds collected from all customer classes.[10]

In the most recently completed program cycle, the 2020–2021 tariff period, energy efficiency saved 44.3 aMW. The target for the current 2022–2023 program cycle is 61.3 aMW.

We made the following changes in the 2022–2023 program cycle:[11]

- Added 85,000 home energy reports to participating gas-only customers
- Added a new industrial pay-for-performance option for industrial systems optimization participants to encourage bundling of capital and O&M measures
- Added a new residential midstream heating ventilation and cooling (HVAC) and water heat program with a focus on engaging distributors to increase sales by reducing first costs and increasing stock
- Added the lean buildings accelerator program to help building owners comply with the new clean buildings requirement
- Increased equipment and weatherization incentives and customized home energy reports for manufactured home customers
- Increased natural gas targets leading to a focus on residential space heat programs, home energy reports, and commercial/industrial retrofit natural gas programs
- Raised the income threshold for the low-income weatherization program from 60 to 80 percent of the area median income (AMI) or 200 percent of the federal poverty level (FPL), whichever is higher
- Reintroduced the lodging rebates program for hotel and motel customers

We anticipate PSE's 2022–2023 electric energy efficiency programs will cost just over $240 million and save 61.3 aMW of electricity.

3.1.2. Distribution Efficiency

The production and distribution efficiency program includes implementing energy conservation measures that prove cost-effective, reliable, and feasible within our distribution facilities.

We implement improvements at PSE's electric substations for efficiency in transmission and distribution (T&D). These improvements focus on phase balancing and conservation voltage reduction (CVR). The methodology used to

[10] See Electric Schedule 120, Electricity Conservation Service Rider, for more information.
[11] See 2020-21 Biennium Conservation Plan Overview for more details on efficiency programs, especially low-income weatherization programs.

determine CVR savings is the Simplified Voltage Optimization Measurement and Verification Protocol provided by the Northwest Power and Conservation Council Regional Technical Forum.[12]

Table C.19 below lists the CVR-related projects completed to date. Going forward, we plan to significantly expand CVR projects tied to implementing the Advanced Metering Infrastructure (AMI) and substation automation projects. These two projects will enable Volt-Var optimization (VVO), an improved CVR method that allows for deeper savings compared to PSE's current CVR implementation method of line drop compensation (LDC).

Savings associated with CVR are affected by several variables, including but not limited to the increasing penetration of distributed energy resources (DERs) we expect in the future. Therefore, the savings from these projects can vary significantly. We are investigating the need for a study that provides an updated energy savings methodology for Volt-Var CVR projects.

Table C.19: Energy Savings from Conservation Voltage Reduction, Cumulative Savings to Date, kWh

Substation	Year Savings Claimed	Date of Implementation	kWh Savings / Year	Savings as (%) of Baseline kWh
South Mercer	2013	11/1/2013	607,569	1.3
Mercerwood	2013	12/8/2013	357,240	0.9
Mercer Island	2014	8/8/2014	859,586	1.3
Britton	2014	12/5/2014	636,197	5.6
Panther Lake	2016	8/27/2015	804,326	1.3
Hazelwood	2016	9/18/2015	1,352,149	1.4
Pine Lakes	2016	9/17/2015	1,163,150	1.3
Fairwood	2018	5/1/2018	768,367	1.2
Rhode Lakes	2018	5/23/2018	1,639,803	1.6
Rolling Hills	2018	5/24/2018	1,359,515	1.5
Phantom Lake	2019	12/19/2018	343,748	0.8
Overlake	2019	12/6/2019	326,644	1.0
Lake McDonald	2020	5/26/2020	404,699	1.0
Maplewood	2021	7/28/2021	911,874	0.9
Marine View	2021	12/2/2021	742,569	1.0
Cambridge	2021	12/13/2021	597,420	1.0
Avondale	2022	12/2/2021	995,168	1.1
Lake Hills	2022	11/15/2021	671,548	1.2
Wayne	2022	12/3/2021	505,679	0.8
Wilkeson	2022	7/28/2021	232,538	0.9
North Bothell	2022	12/2/2021	576,033	1.0

12 rtf.nwcouncil.org.

Substation	Year Savings Claimed	Date of Implementation	kWh Savings / Year	Savings as (%) of Baseline kWh
Average to Date	**-**	**-**	**755,039**	**1.3**
Total to Date	**-**	**-**	**15,855,822**	**-**

3.1.3. Generation Efficiency

In 2014, PSE worked with the Conservation Resource Advisory Group (CRAG) to refine the boundaries of what to include as savings under generation efficiency. We determined we would include only parasitic loads[13] served directly by a generator in the savings calculations available for generation efficiency upgrades; we would not include generators that serve parasitic loads from the grid. Using this definition, we completed site assessments in 2015. The assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and meager operating hours made these opportunities not cost-effective.

Puget Sound Energy staff will continue to study efficiency opportunities in these facilities and report on cost-effective savings we identify and implement in the 2022 and 2023 Annual Conservation Reports.

3.1.4. Distributed Generation

Puget Sound Energy offers cogeneration and combined heat and power incentives in our commercial and industrial programs. However, to date, we have not implemented any projects.

We discuss renewable distributed generation programs in this appendix's Customer Renewable Energy Programs section.

3.1.5. Demand Response

To meet PSE's Clean Energy Implementation Plan (CEIP) target of 23.7 MW of DR capacity reduction by 2025, we issued a distributed energy resource (DER) request for proposals (RFP) on February 7, 2022. Puget Sound Energy received responses from nine unique bidders proposing DR programs utilizing various technologies, including HVAC, water heat, battery energy storage, electric vehicle, sighting, building automation systems, and behavioral. The proposals total 161 MW of winter capacity. Puget Sound Energy plans to evaluate all proposals and implement the DR program(s) in 2023.

In the meantime, PSE's Customer Energy Management group plans to operate geographically targeted pilots in both a natural gas (Duvall) and an electric (Bainbridge Island) program. We implemented these programs in late 2022, following some initial contracting delays.

[13] Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the parasitic load.

3.2. Customer Renewable Energy Programs

This section describes PSE's customer renewable energy programs. We divide these programs into two general categories. The voluntary subscription products serve customers who want additional renewable energy, including Green Power, Solar Choice, Community Solar, and Green Direct programs. The Customer Connected Solar products include Net Metering and Local Energy Development, which serve customers who generate distributed renewable energy on a small scale.

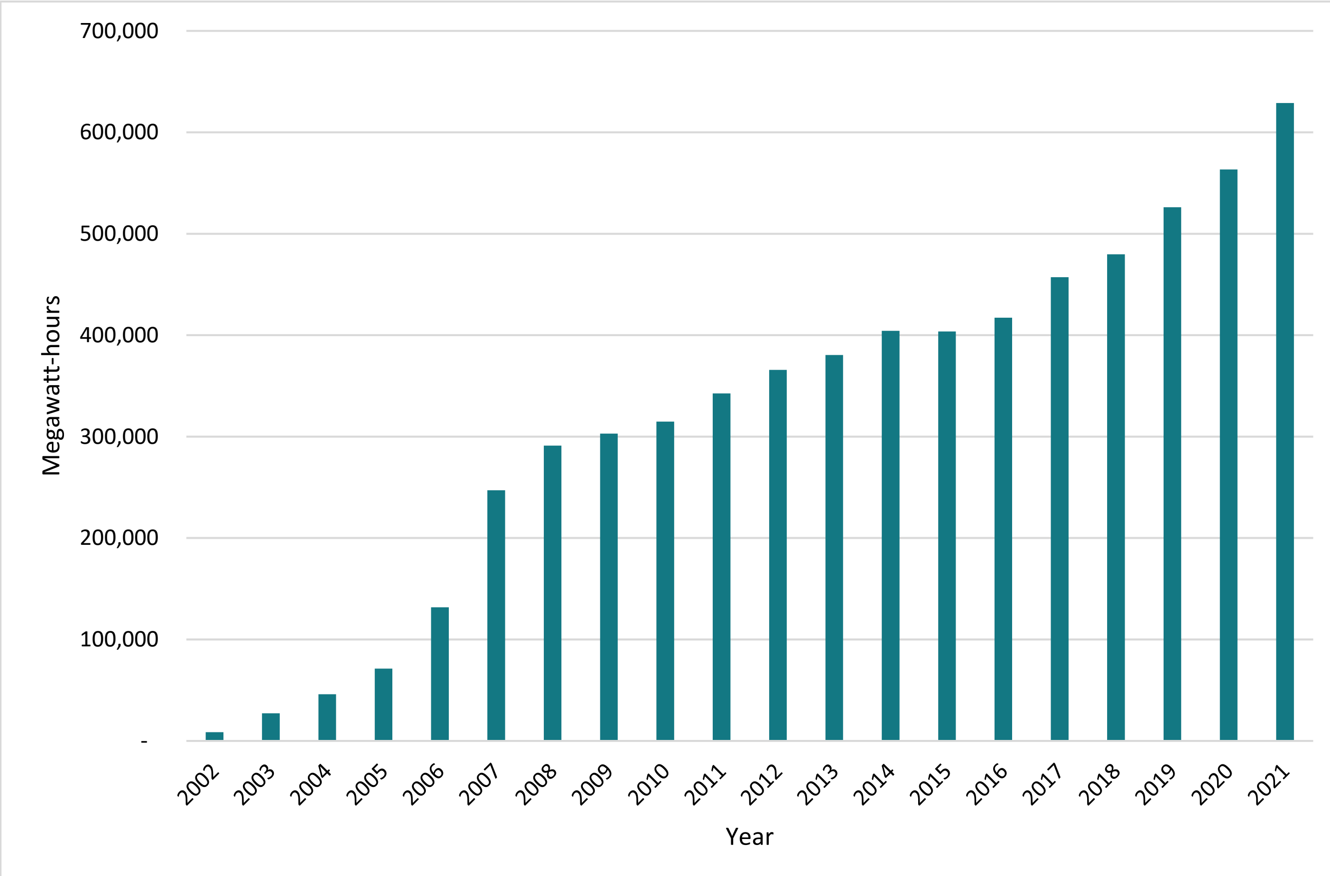
3.2.1. Renewable Power Purchasing Programs

In the following sections, we describe the voluntary subscription products for customers interested in purchasing additional renewable energy.

Green Power Program

We launched the Green Power Program in 2001. This program allows customers to voluntarily purchase Renewable Energy Credits (RECs) from qualified renewable energy resources. The program has grown to include more than 66,000 participants at the end of 2021. Customers purchased an additional approximately 19.5 percent of MWh during 2019–2021, ending the period with sales of 628,945 MWh in 2021 (Figure C.3).

Figure C.3: Green Power MWh Sold 2002–2021



The Green Power Program built a portfolio of RECs from various renewable energy technologies and projects in the Pacific Northwest. In mid-2020, we requested a quote (RFQ) seeking RECs to supply the Green Power program for 2021–2023. The Green Power Program also purchased RECs from small, local, and regional producers to support small-scale renewable resources. These small producers included:

- FPE Renewables
- Farm Power Rexville
- Edaleen Cow Power
- Van Dyk-S Holsteins
- Rainier Biogas
- 3Bar G Community Wind
- First Up! Knudson Community Wind
- Ellensburg Community Solar
- Swauk Wind
- LRI Landfill Gas

Many of these entities also provide power to PSE under the Schedule 91 contracts discussed in the Long-Term Contracts section of this appendix.

Increasing the number of utility-scale solar projects in Idaho and Oregon allowed us to grow the number of RECs sourced from solar projects. We would prefer to source RECs first from projects in Washington and then from Oregon and Idaho. However, the supply of Pacific Northwest RECs continues to tighten as voluntary program sales have grown and we dedicate more resources to serving compliance targets. This constricted market has made it more difficult to source all our supplies from the region. To maintain current program pricing, we have begun sourcing from other locations in the WECC, including Montana, Utah, Colorado, California, British Columbia, and partly from national REC sources for the Large Volume Green Power product. We believe this trend will continue as CETA compliance increases the demand for renewable energy in the region.

Green Power Community Grants

Over the past 15 years, the Green Power program has also committed more than $3,700,000 in grant funding to 15 cities and 45 local organizations in our electric service area to install solar projects to support low-income or Black, Indigenous, and People of Color (BIPOC) communities and the organizations that serve them. For example, in late 2020, PSE awarded solar grants to 14 organizations in six counties to be installed in 2021. The following organizations received more than $1,000,000 to install more than 500 new kW of solar:

- Boys and Girls Clubs of Skagit County
- Boys and Girls Club of South Puget Sound
- Camp Korey
- Friends of the Manchester Library
- Helping Hands Food Bank
- Hopelink, Institute for Washington's Future
- King County Housing Authority – Vantage Point
- Lummi Nation School
- Nisqually Indian Tribe
- Skagit Valley Hospitality House Association
- South Whidbey Good Cheer Food Bank
- Sustainable Connections
- YWCA

In 2021, PSE issued another solicitation and awarded over $900,000 in grant funding to 11 organizations for solar installations to non-profits, public housing authorities, or tribal entities serving low-income or BIPOC community members in PSE's electric service area. We expect most projects to be installed by early 2023. We issued another solicitation in mid-2022 for $750,000 for solar projects installed in 2023.

Green Power Rates

Puget Sound Energy provides two rate schedules in the Green Power program. The first, under Schedule 135, serves residential and commercial Green Power customers and was launched in 2001. The current rate for green power is $0.01 per kWh. Customers can purchase 200 kWh blocks for $2.00 per block with a two-block minimum or participate in the 100 percent Green Power Option. We introduced this program option in 2007; it adjusts the customer's monthly green power purchase amount to match their monthly electric usage. In 2021, the average residential customer purchase was 708 kWh per month, and the average commercial customer purchase was 1530 kWh. There are more than 80,000 subscribers to the Green Power and Solar Choice programs.

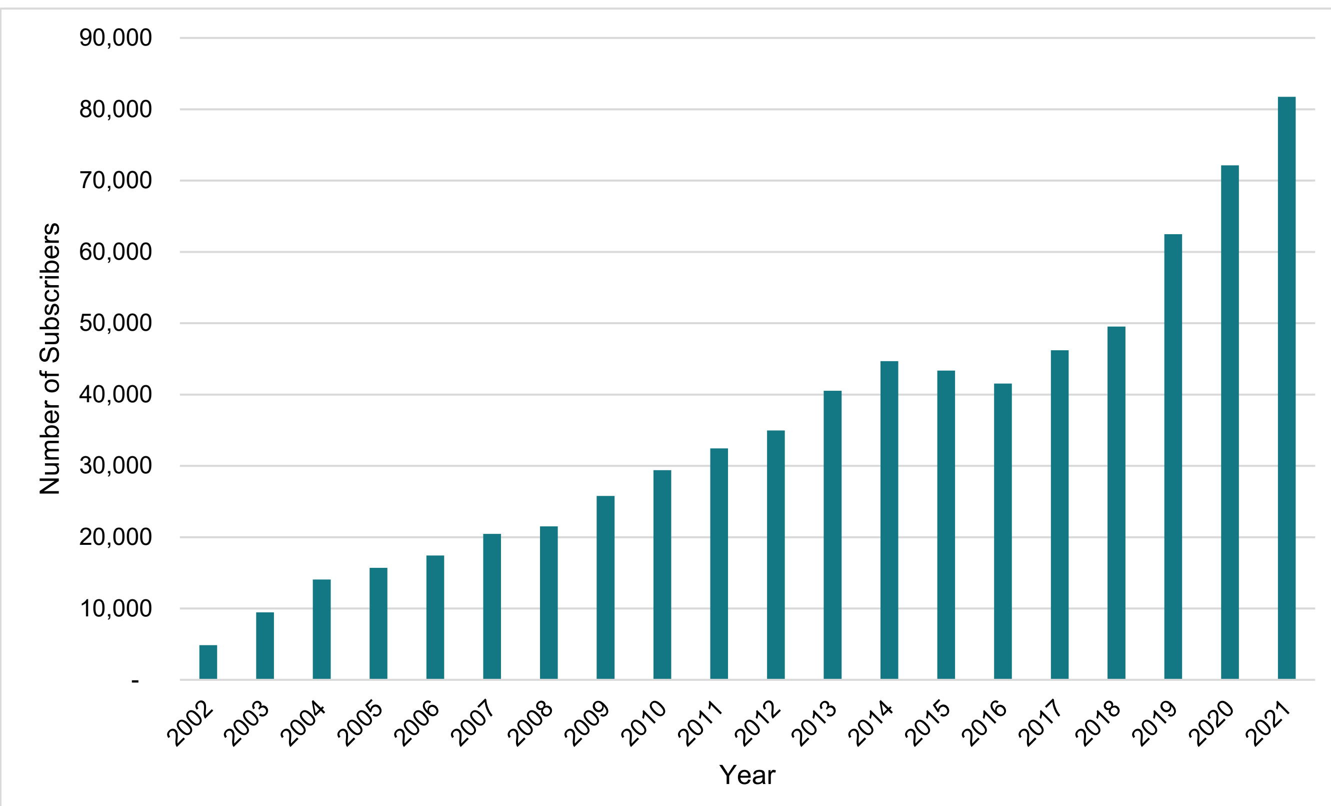
The second schedule is for customers who purchase more than one million kWh annually from the Green Power program and is detailed under Schedule 136. In 2022, PSE received approval from the Commission to increase the large-volume green power rate from $0.0035 per kWh to $0.006 per kWh. We made this latest change to better align the large volume rate with regional and national REC pricing. We will work to balance pricing with a mix of national and regionally produced RECs. The average 2021 large-volume purchase under Schedule 136 was 43,617 kWh per month. This product has attracted approximately 35 customers since we introduced it in 2005.

Solar Choice

In September 2016, the Commission approved PSE's Solar Choice program, a renewable energy product for residential and small to mid-size commercial customers. Like the Green Power program, Solar Choice allows customers to purchase retail electric energy from qualified renewable energy resources voluntarily; in this case, all the resources are solar energy facilities in Washington, Oregon, and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. We add the purchases to their monthly bill. We officially launched the program in April 2017. As of December 2021, the program had 15,612 participants. These customers purchased 42,526 megawatt-hours of solar energy in 2021, a 37 percent increase from 2020 to 2021.

Figure C.4 illustrates the number of subscribers in our Green Power and Solar Choice offerings, by year. Of our 81,739 Green Power and Solar Choice subscribers at the end of 2021, 80,514 were residential customers, 1,115 were commercial accounts, and 110 accounts were under a large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 7,350, Olympia with 6,909, and Kirkland with 4,564.

Figure C.4: Green Power and Solar Choice Subscribers, 2002–2021



Community Solar

The Commission approved the PSE Community Solar Program for up to 20 MW in January 2021. Community Solar allows PSE electric customers to share the benefits of 100 percent local solar power. By subscribing to shares of a local solar array of their choice, PSE electric customers can replace some or all of their regular electricity use from solar energy projects located in western and central Washington and interconnected to PSE's distribution system. Each Community Solar share is $20 per month; however, PSE dedicates 20 percent of the available program shares to serving income-eligible customers at no cost. All Community Solar participants receive a monthly bill credit of $0.045 per kWh generated by the customer's solar energy share(s). Monthly energy credits vary based on the real-time production of the solar energy sites. One share is equal to 1.46 kW. Customers must commit to an initial one-year term and can cancel their subscription any time after that year.

The first Community Solar site opened in November 2021 on the roof of Olympia High School. Another site started operating in March 2022 at Pine Lake Middle School in Sammamish. A third site in Bonney Lake was completed in October 2022. We additionally contract power from Penstemon and Urtica solar sites, both located in Kittitas County. These sites opened in January and November of 2022, respectively. As we put additional Community Solar sites in service, subscriptions will become available for restricted shares per site. When a solar site is fully subscribed, we add customers to a waitlist for future availability at that site, or they may choose to subscribe to a different site if one is available.

Green Direct

We launched the Green Direct program on September 30, 2016, after the Commission approved it. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A,[14] Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large commercial (10,000 MWh per year or more of load in PSE's service area) and government customers from specified wind and solar resources.

For Phase I, PSE signed a 20-year PPA for the output from the 137 MW Skookumchuck Wind project in Lewis County. Customers could elect to enroll for 10, 15, or 20 years. The customer continues to receive and pay for all the standard utility services for safety and reliability. We charge customers for the total energy cost from the new plant, but they receive a credit for the energy-related power costs from the company.

Phase I of Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. By the end of June 2017, less than two months later, the wind facility was fully subscribed to 21 customers. Enrollees include companies like Starbucks, Target Corporation, REI, and government entities like King County and the City of Olympia. The Skookumchuck Wind project reached commercial operation in November 2020.

For Phase II, PSE issued an RFP to identify a new resource (or resources) in August 2017. In early 2018, PSE selected a 120 MW solar project in south-central Washington that we expected to achieve full commercial operation in 2022. Following selection, we proposed a blended rate of the Phase I wind and Phase II solar projects, which the

[14] RCW 19.29A

Commission approved in July 2018. Phase II enrollment opened on August 31, 2018, and was entirely subscribed by 16 customers; four were wait-listed. We subsequently requested to expand the project size from 120 MW to 150 MW, which the Commission approved. The expansion allowed all 20 customers to participate. Phase II customers include the following:

- Amazon
- Bellevue College
- Kaiser Permanente
- Port of Bellingham
- Providence Health & Services
- Several customers from Phase I requesting additional supply
- Six Washington State agencies
- The cities of Kent and Redmond
- The Issaquah School District
- T-Mobile
- UW Bothell
- Walmart

3.2.2. Customer Connected Renewables Programs

Puget Sound Energy offers two customer programs for customers who install small-scale generation: a net metering program and the Washington State Renewable Energy Production Incentive Program. These are not mutually exclusive, and most customer-generators were enrolled in both programs until the Production Incentive Program closed to new participants in 2019.

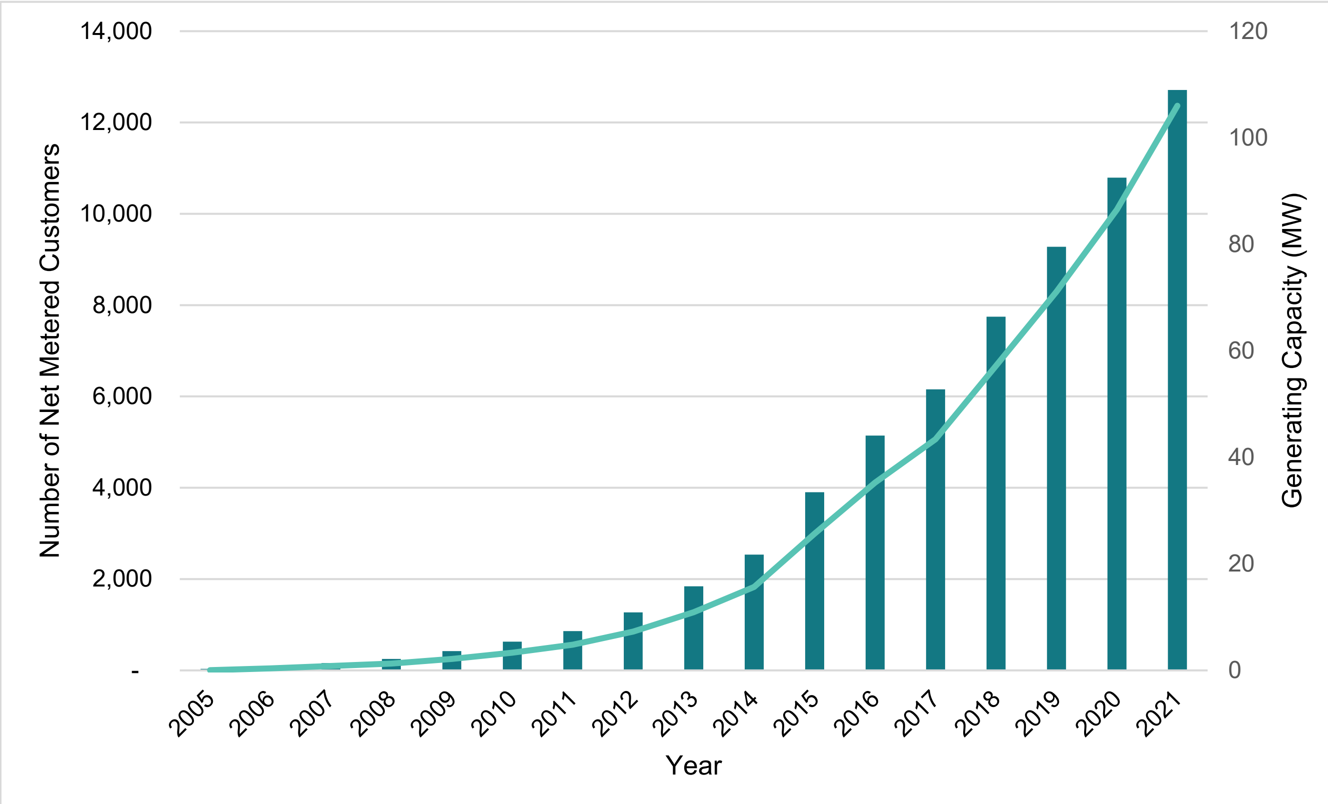
Net Metering Program

The Net Metering Program is defined in Rate Schedule 150 and governed by RCW 80.60.[15] This program began in 1999 and was most recently updated by the Washington State Legislature in Engrossed Substitute Senate Bill 5223 on July 28, 2019. Net metering allows customers who generate renewable electricity to offset the electricity provided by PSE. We subtract the amount of electricity the customer generates and sends back to the grid from the amount provided by PSE, and the net difference is what the customer pays monthly. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over a month. According to state law, customers can carry over the banked energy until March 31 each year, when we reset the account to zero. The interconnection capacity allowed under net metering is 100 kW alternating current (AC).

Customer interest in small-scale renewables has increased significantly over the past 20 years, as shown. The program has more than doubled the number of participating customers in the last five years, with strong growth continuing even after the closure of the State Production Incentive Program. As of May 1, 2022, the program has more than 13,500 participants (Figure C.5).

[15] RCW 80.60

Figure C.5: Net Metered Customers, 1999–2021



Most customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 8 kW, but there are also small-scale hydroelectric generators and wind turbines (Table C.20). By mid-2022, PSE was net metering more than 113 MW (AC) of generating capacity.

Table C.20: Interconnected System Capacity by Type of System, as of Q2 2022

System Type	Number of Systems	Average Capacity per System Type (kW [MW])	Sum of All Systems by Type (kW [MW])
Hybrid: solar/wind	16	9.3 [0.0093]	184 [0.184]
Micro hydro	6	15.7 [0.0177]	101 [0.101]
Solar array	13,546	8.37 [0.008]	113,422 [113]
Wind turbine	28	2.7 [0.0027]	80 [0.08]
Total	**13,597**	**8.0 [0.008]**	**113,82 [113.827]**

These small-scale renewable systems are distributed over a wide area of PSE's service territory (Table C.21).

Table C.21: Net Metered Systems by County

County	Number of Net Meters
Whatcom	2,744
King	4,362
Skagit	1,230
Island	646
Kitsap	1,308
Thurston	1,775
Kittitas	681
Pierce	851
Total	**13,597**

Customer preference, declining prices, and federal tax incentives drive customer solar PV adoption. Residential customers were 92 percent of all solar PV by number and 83 percent by nameplate capacity. In 2021, we engaged in a project to link our Interconnection portal with our customer billing system, Systems Applications, and Products in Data Processing (SAP) and attach system information to the customer premise. This upgrade allows for a smoother interconnection process, greater visibility of customer generation on our distribution system, and a streamlined move-in and move-out process for customers with solar. We continue to examine our processes to scale up customer generation.

Renewable Energy Production Incentive Payment Program

The Washington State Renewable Energy Production Incentive Program is a production-based financial incentive for solar, wind, and bio-digester-generating systems customers. Puget Sound Energy has voluntarily administered this state incentive to qualified customers under Schedule 151 since 2005. For a PSE customer-generator to participate in Schedule 151, they must:

- Be a PSE customer with a valid interconnection agreement with PSE to operate their grid-connected renewable energy system.
- Be certified (as named on the PSE account) by the Washington State Program Administrator as eligible for annual incentive payments.
- Have a system that includes production metering capable of measuring the energy output of the renewable energy system.

In June 2019, the Washington State Program Administrator issued a notice that this program's budget was fully obligated, and we formally withdrew our voluntary participation effective December 12, 2019. We continue to administer annual incentive payments to all certified program participants, but customers installing new solar systems after December 12, 2019, are not eligible to participate in this program. Thus, the State Production Incentive Program is no longer a driver of solar energy adoption.

Annual Production Reporting and Payments

Puget Sound Energy measures and reports the kilowatt hours generated by participants' renewable energy systems annually and makes incentive payments to eligible customers as determined by the Washington State Program Administrator. Legacy participants (those certified to participate by the Department of Revenue before October 1, 2017) with valid certifications received payments of up to $5,000 per year for electricity produced through June 30, 2020, at rates ranging from $0.14 to $0.504 per kWh. The year 2020 was the final payment year for 5,300 legacy program participants.

Participants who obtained state certification on or after October 1, 2017, and who maintain ongoing eligibility requirements are eligible for up to eight years of annual incentive payments on kilowatt-hours generated from July 1, 2017, through June 30, 2029. The incentive rate for these participants ranges from $0.02 to $0.21 per kWh based on system size, technology, and certification date. The Washington State Program Administrator determines participant eligibility, rates, terms, payment limits, and incentive payment amounts.

Puget Sound Energy has administered more than $95 million to our customers in production incentive payments through 2021. We recover these payments through state tax credits.

GENERIC RESOURCE ALTERNATIVES
APPENDIX D

PUGET SOUND ENERGY

Contents

1. Introduction 1
   1.1. Cost Assumptions 2
   1.2. Operating Characteristics 2
2. Renewable and Storage Resource Technologies and Assumptions 3
   2.1. Biomass 4
   2.2. Wind 5
   2.3. Solar 9
   2.4. Energy Storage 14
   2.5. Hybrid Technologies 17
3. Thermal Resource Technologies and Assumptions 17
   3.1. Baseload Combustion Turbine Technologies 18
   3.2. Peaker Technologies 18
   3.3. Modeling Assumptions 19
4. New Resource Technologies and Assumptions 24
   4.1. Advanced Nuclear Small Modular Reactors 24
5. Resource Technologies Not Modeled 26
   5.1. Renewable Resources Not Modeled 26
   5.2. Energy Storage Not Modeled 31
   5.3. Thermal Resources Not Modeled 33
6. Tables 35

1. Introduction

Generic resources are theoretical electric generating resources used to develop Puget Sound Energy's (PSE) long-term capacity expansion planning model. As electric generating and storage technologies evolve, assumptions change. We update generic resource assumptions, including cost, operating, and availability, to align with the most recent and industry-reliable data for each Integrated Resource Plan (IRP). This appendix is a catalog of the supply-side — before the meter — generic resource alternatives we considered in the 2023 Electric Progress Report (2023 Electric Report).

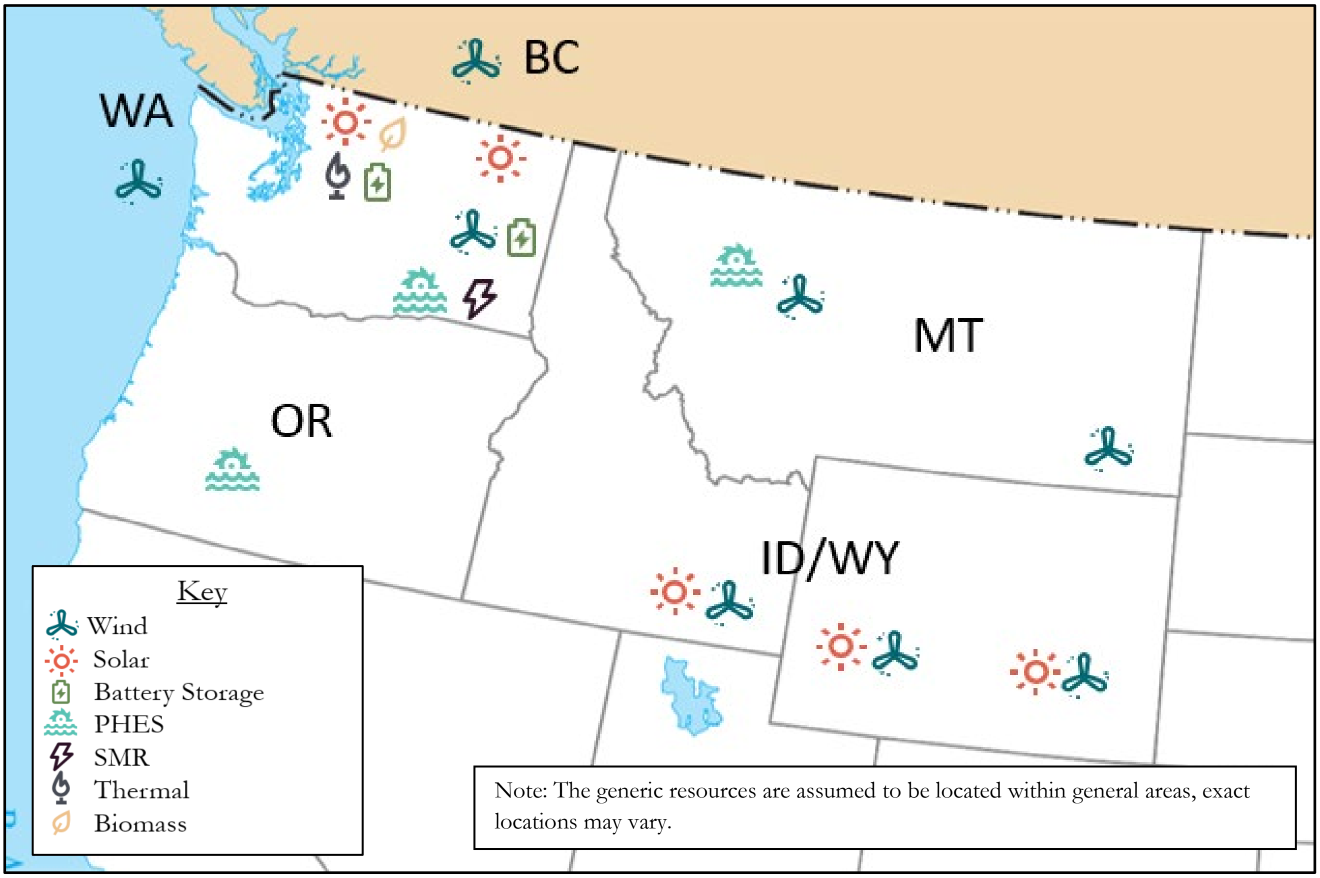
➔ We describe our planning models in Appendix G: Electric Price Models.

Here we describe mature technologies and new ways to generate power, including those commercially viable in the near- and mid-term. We explain the technologies available and the corresponding assumptions we adopted in our long-term capacity expansion model for each resource type. We primarily focused on updating cost assumptions in this report. Conversely, operating assumptions are generally consistent with the 2021 IRP, with some notable exceptions, such as operating life and reliable capacity assumptions. We present the data sources we consulted in Sections 1.1 and 1.2.

Although generic resources are not associated with a specific location, geography can heavily influence assumptions. Therefore, each of our generic resources is region-specific (we modeled Washington wind and Montana wind as separate generic resources) to best capture realistic future costs and operating characteristics in the modeling process. Figure D.1 presents the assumed geographic locations of the various generic resource alternatives we analyzed for this report.

➔ We also analyzed demand-side — after the meter — resources to help meet resource needs and discussed these in Appendix E: Conservation Potential Assessment.

Figure D.1: Generic Resource Alternatives Locations



1.1. Cost Assumptions

We sourced the generic resource costs for renewable, energy storage, and thermal resources described in the following pages primarily from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB). We also used input from publicly available data sources, including the U.S. Energy Information Administration (US EIA), Lazard, the Northwest Power and Conservation Council (NPCC), other national laboratories, and other regional IRPs. All cost assumptions are in 2020 dollars, with a 2.5 percent inflation applied through the planning horizon.

➔ Generic resource cost assumptions, including all data sources and averaging assumptions, are available in Appendix H: Electric Analysis and Portfolio Model.

1.2. Operating Characteristics

The following sources informed our generic resource operating characteristics:

- NREL's 2022 ATB[1]
- PSE's experience in owning, operating, and developing electric-generating resources
- Solar and wind data provided by the consulting firm DNV
- 2019 HDR Generic Resource Costs for Integrated Resource Planning report[2]

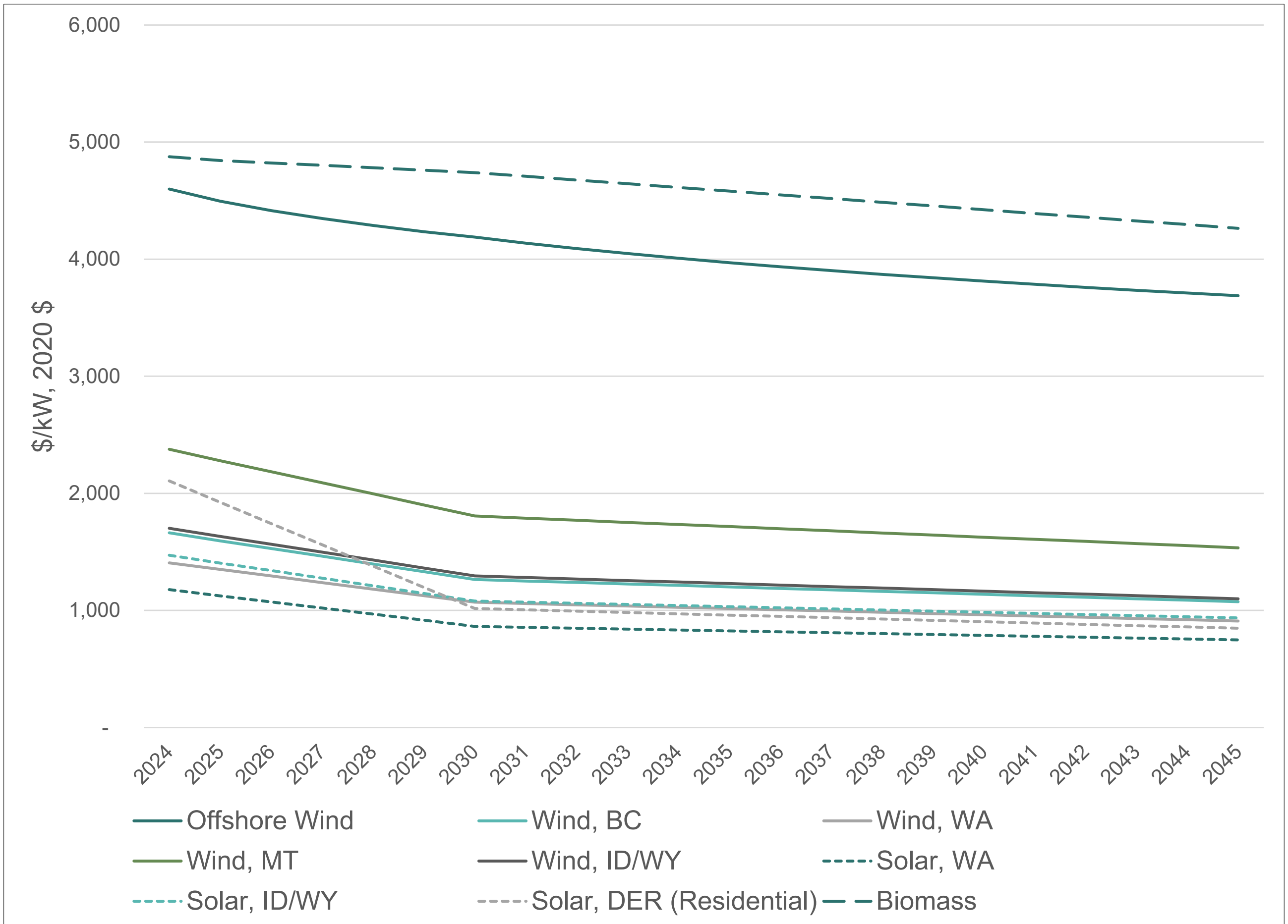
2. Renewable and Storage Resource Technologies and Assumptions

We modeled five types of renewable energy resources in this report: biomass, wind, solar, storage, and hybrid technologies. We described these technologies in the following sections and include cost assumptions and commercial availability. Table D.1 through Table D.5 further summarize the technology parameters we modeled. Figure D.2 shows the capital cost curves for each renewable technology through the planning horizon.

1 https://atb.nrel.gov/electricity/2022/index.

2 https://www.pse.com/-/media/PDFs/IRP/2022/03222022/2019_HDR_GenericResourceAssumptionsReport_rev4.pdf?sc_lang=en&modified=20220506194408&hash=E6B1FDDF642DABBE25C1A42AFAB595D2.

Figure D.2: Capital Cost Curves for Renewable Energy Resources



2.1. Biomass

Biomass, in this context, refers to burning woody biomass in boilers. Most existing biomass in the Northwest works with steam hosts, also known as cogeneration or combined heat and power. Biomass is found mainly in the timber, pulp, and paper industries. That dynamic has limited the amount of biomass energy available to date. The typical biomass plant size is 10–50 MW. One significant advantage of biomass plants is they can operate as a baseload resource since they are not variable, unlike wind and solar. Biomass is considered separately from waste-to-energy technologies, including municipal solid waste, landfill, and wastewater treatment plant gas, which are discussed in Section 5.1: Renewable Resources Not Modeled.

We modeled biomass as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters reflect a cogeneration facility near a timber mill and are the same parameters presented in our 2021 with updates to cost data (e.g., capital costs, operations and maintenance, transmission). We show the operating assumptions for the 2021 IRP and this report in Table D.1.

Biomass technology is commercially available. Greenfield development of a new biomass facility — designing, permitting, and constructing a completely new, previously unplanned facility — requires approximately three years.

2.2. Wind

Wind energy is the dominant renewable technology used in the Pacific Northwest region to meet Washington State's Renewable Portfolio Standards (RPS) and Clean Energy Transformation Act (CETA) requirements. Wind technology is mature, is cost effective, is acceptable in various regulatory jurisdictions, and has a large utility-scale compared to other renewable energy technologies. However, wind also poses challenges. Wind power generation does not correlate with customer demand because the availability of wind is variable. Therefore, we must have other, more flexible resources ready to respond when wind is unavailable. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a power system that is already congested.

2.2.1. Land-based Wind Technology

Land-based wind turbine generator technology is mature. Although the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity, and increased wind capture (efficiency). Commercially available turbines range in capacity from 2-4 MW, with an average of 2.55 MW per turbine. Hub heights and blade diameters average 90 meters and 121 meters, respectively[3]. The primary factor driving changes in wind technology is the need to site new development in less energetic wind sites because premium high-wind spots are already developed. This technology will likely continue to advance and become more accessible as the current generation of turbines pushes the physical limits of existing transportation infrastructure. The U.S. Department of Energy is researching potential solutions, including designing more slender, flexible blades and developing towers that crews can assemble on-site.[4]

The cost of installing a wind turbine includes the turbine, foundation, roads, and electrical infrastructure. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.36 to $55.37 per MWh (in 2021 U.S. dollars) for new wind resources entering service in 2024. This cost depends heavily on the capacity factor of wind at the location and federal tax credits, which, even with the extension under the Inflation Reduction Act (IRA), will likely decline or expire during the planning horizon.[5] Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting, major equipment lead time, and one year for construction.

2.2.2. Offshore Wind Technology

Offshore winds blow at higher speeds and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can make significantly more electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and an average wind speed of 14 mph.

[3] Lawrence Berkeley National Laboratory, Wind Energy Technology Update: 2020 Edition: https://emp.lbl.gov/sites/default/files/2020_wind_energy_technology_data_update.pdf

[4] https://www.energy.gov/eere/articles/wind-turbines-bigger-better

[5] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022, March 2022: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

However, offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, mainly because of turbine upgrades required for operation at sea and increased expenses related to turbine foundations, the balance of system infrastructure, interconnection, and installation, and the difficulty of maintenance access. In addition, developing infrastructure incurs one-time costs to support offshore construction, such as vessels to erect foundations and install turbines and related port facilities.

Wind turbine generators used in offshore environments require durability modifications to prevent corrosion and to operate reliably in harsh marine environments. Their foundations must be designed to withstand storm waves, hurricane-force winds, and even ice floes. The engineering and design of offshore wind facilities depend on site-specific conditions, particularly water depth, the geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with various styles for each category. The fixed foundation is a proven technology used throughout Europe. Monopiles, the most prevalent foundation type, are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters. However, roughly 90 percent of the offshore U.S. wind resource occurs in waters too deep for a fixed foundation, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, but this technology is not commercially mature.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. A power cable connects each turbine to an electric service platform (ESP). High voltage cables, typically buried beneath the seabed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

In Europe, offshore wind is a proven technology in shallow coastal waters. As of 2020, Europe's total installed capacity was 25 GW, with turbines spanning 12 countries[6]. The United States currently has two operational offshore wind projects — the 30 MW Block Island Wind Farm off the coast of Rhode Island, which began operation in December 2016, and the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project, completed in June 2020. As a result of this dearth of data, reliable capital cost estimates for large-scale U.S. installations are unavailable.

However, this will change during the planning horizon for the 2023 Electric Report, as the Biden administration has set a goal of achieving 30 GW of offshore wind by 2030 and has subsequently approved the first two commercial-scale projects in the nation, Vineyard Wind and South Fork Wind projects, which are currently under construction. Additionally, in June of 2022, the administration launched the Federal-State Offshore Wind Implementation Partnership, intended to accelerate the offshore wind progress[7]. According to The American Clean Power Association, project developers expect 12 offshore wind projects totaling 10,300 MW to be operational by 2026[8]. As the market develops, costs should decrease as we all gain experience. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve more significant economies of scale in the years ahead.[9]

6 https://windeurope.org/intelligence-platform/product/offshore-wind-in-europe-key-trends-and-statistics-2020
7 https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/23/fact-sheet-biden-administration-launches-new-federal-state-offshore-wind-partnership-to-grow-american-made-clean-energy
8 https://cleanpower.org/facts/offshore-wind
9 https://www.energy.gov/eere/wind/offshore-wind-research-and-development

2.2.3. Modeling Assumptions

We modeled wind in the following locations for this report: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho, and Washington offshore. Table D.2 summarizes the wind resources we modeled in the 2023 Electric Report and those we modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Wind Locations

Eastern Washington wind is in Bonneville Power Administration's (BPA) balancing authority, so this wind requires only one transmission wheel – transfer from one transmission provider to another – through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require three transmission wheels to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require three transmission wheels to deliver power in 2024-2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[10] transmission projects would be complete. Once constructed, we assume two wheels will deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

We modeled offshore wind located 16 miles off Grays Harbor County, Washington coast. Offshore wind requires a marine cable to interconnect the turbines and bring the power back to land. Once on land, a transmission wheel through BPA to PSE would be necessary.

Generate Wind Shapes

A wind (or solar) shape is the net capacity factor of a wind turbine (or solar array) at a specific location over time. A wind shape provides data on how well a given wind resource will perform. Puget Sound Energy engaged the consulting company DNV to generate wind shapes for each generic wind resource. Using a consulting firm was a departure from the 2021 IRP when we used the NREL Wind Toolkit database[11] to derive wind shapes. This 2023 Electric Report presents wind shapes as a net capacity factor for every hour within one calendar year. Figure D.3 shows the wind shapes for the generic wind resources we analyzed for this report.

DNV used an internal wind mapping system to generate hourly shapes at a 5-kilometer resolution for each potential wind site. This modeling process involves conducting dynamical downscaling to generate high-resolution mesoscale wind maps. Inputs include soil and sea surface temperatures, moisture levels, and NASA's MERRA-2 reanalysis dataset, which contains data obtained from various sources, including rawinsondes, radar, land-based stations, aircraft, ships, scatterometer wind readings, and NASA's EOS satellites. Outputs from this modeling include an hourly time series of wind speed, temperature, pressure, and direction at hub heights.

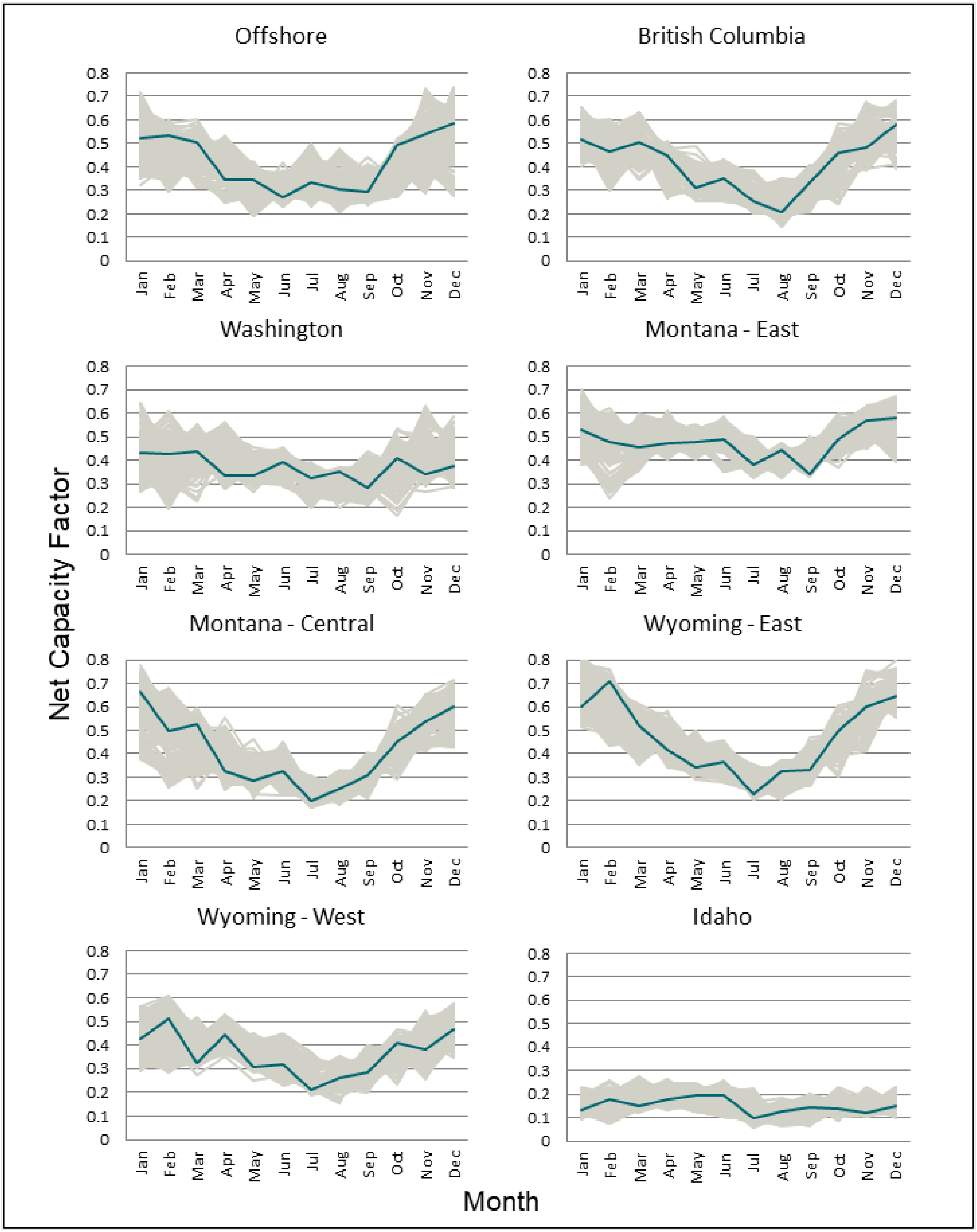
DNV subsequently used this output, in conjunction with turbine model and power data, as inputs to a stochastic model. The stochastic model generated 1,000 stochastic time series to represent the net capacity factor of a wind

10 http://www.gatewaywestproject.com
11 https://www.nrel.gov/grid/wind-toolkit.html

turbine for each site over the 22-year planning period. This methodology maintained daily, seasonal, and annual cycles from the original data. The stochastic model also maintained spatial coherency of weather, generation, and system load to preserve the relationships of projects across a region. DNV then randomly selected a sample of 250 annual hourly draws for each site, verified the data were representative of the total distribution, and provided the data to PSE for modeling purposes.

These updated wind shapes from DNV are generally consistent across sites with the wind shapes provided in the 2021 IRP, except for the existing Skookumchuck wind resource and the generic Idaho wind resource. Upon examining these resources further, we determined that the NREL wind toolkit database lacked wind speed data near the sites, so it did not adequately represent the Skookumchuck and Idaho wind sites. Therefore, we determined the DNV shapes provided a more accurate representation of wind conditions at these sites and adopted those shapes for this 2023 Electric Report.

Figure D.3: Seasonal Wind Shapes for Generic Wind Resources



2.3. Solar

Renewable portfolio standards (RPSs), falling prices, and tax incentives drive most utility-scale solar development in the United States, with solar installations accounting for 50 percent of total capacity additions across the U.S. in Q1

2022.[12] With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic growth has been relatively slow in the Northwest. However, since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably, and solar remains an appealing renewable technology for us to procure to meet RPS and CETA requirements. Like wind technology, solar resources pose challenges that include daily and hourly variability in power generation, the misalignment with generation and customer demand, and the need for the long-haul transmission to bring solar power generated in sunnier locations into PSE's system.

2.3.1. Solar Technologies

Photovoltaic (PV) technology, semiconductors that generate direct electric currents, uses solar radiation to generate electricity directly. The current typically runs through an inverter to create alternating current, which ties into the grid. Most PV solar cells are silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film PVs, have gained substantial market share. Significant ongoing research efforts continue for all PV technologies and have helped increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays ranging from a few watts for sensor or communication applications to hundreds of megawatts for utility-scale power generation. Photovoltaic systems can be installed on a stationary frame at a tilt to capture the sun (fixed-tilt) best or on a frame than can track the sun from sunrise to sunset.

Concentrating and bifacial PVs are high-efficiency technologies. Concentrating photovoltaics use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems. Bifacial photovoltaic modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

Distributed solar uses similar technologies to utility-scale PV systems but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This scenario means that distributed solar systems do not have the same costly transmission requirements as utility-scale systems. Distributed solar may include rooftop or ground-mounted systems, such as parking lot canopies.

The Solar Electric Industries Association (SEIA) reports that as of Q1 2022, the U.S. has installed over 121 GW of total solar capacity, with an average annual growth rate of 33 percent over the last ten years. Solar has ranked first or second in new electric capacity additions every year for the last nine years. Through early 2022, 46 percent of all new electric capacity added to the grid came from solar.[13] According to SEIA's U.S. Solar Market Insight report for Q4 2021, modeled U.S. national average costs for utility fixed-tilt and tracking projects averaged $0.82 and $0.95 per

[12] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

[13] Solar Electric Industries Association (SEIA), Solar Industry Research Data: https://www.seia.org/solar-industry-research-data. Accessed 6/24/2022.

Watt$_{dc}$, respectively; costs for residential systems had reached approximately $3.06 per Watt$_{dc}$; and costs for commercial systems had reached $1.45 per Watt$_{dc}$.[14]

2.3.2. Modeling Assumptions

We modeled two solar PV applications for this report: a utility-scale, single-axis tracking PV technology, and a residential-scale fixed-tilt, rooftop, or ground-mounted PV technology. We modeled six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho, and residential-scale rooftop or ground-mounted PV solar in western Washington. Table D.3 summarizes the solar resources modeled in the 2023 Electric Report and those modeled in the 2021 IRP for reference. We held operating assumptions consistent with the 2021 IRP values, except for capacity factors, ELCC calculations, and cost assumptions.

Generic Solar Locations

Washington solar resources are located either within PSE's service territory or in BPA's balancing authority, which would require one transmission wheel to PSE. However, Wyoming and Idaho solar resources are outside BPA's balancing authority and will need three transmission wheels to deliver the power to PSE's service territory from 2024–2030. From 2031 through the end of the planning horizon in 2045, we assumed the Gateway West[15] transmission project would be complete. Once constructed, we assumed two wheels to deliver power from Wyoming and Idaho: from Aeolus, Wyoming, to Hemmingway, Idaho, then from Hemmingway, Idaho, to Longhorn, Washington.

Solar Shape Generation

We used specific solar generation profiles or shapes provided by DNV. Using a consulting firm was a departure from the 2021 IRP when we used the shapes derived using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB)[16] and then modeled using NREL's System Advisor Model (SAM) to create realistic generation profiles for each location. For this report, DNV generated 1,000 stochastic series to represent each site over a 22-year window for a total of 22,000 simulated years.

This method relied on inputs that included 22-year hourly solar power time series based on historical irradiance data and load and temperature inputs provided by PSE. Irradiance data was sourced from NASA's Geostationary Operational Environmental Satellites and processed by DNV to account for regional loss factors for each site. Loss factors include temperature, shading, soiling, availability, electric, inverter, and transformer losses.

All resources were modeled with a DC (direct current) to AC (alternating current) ratio of 1.3, and azimuth angles were assumed to be south facing. Utility-scale resources were modeled as ground mounted with single-axis tracking panels, whereas residential-scale resources were modeled as fixed-tilt for rooftop and ground-mounted units.

This methodology maintained daily, seasonal, and annual cycles from the original data and spatial coherency of weather, generation, and system load to preserve how projects are related across a region. A sample of 250 annual

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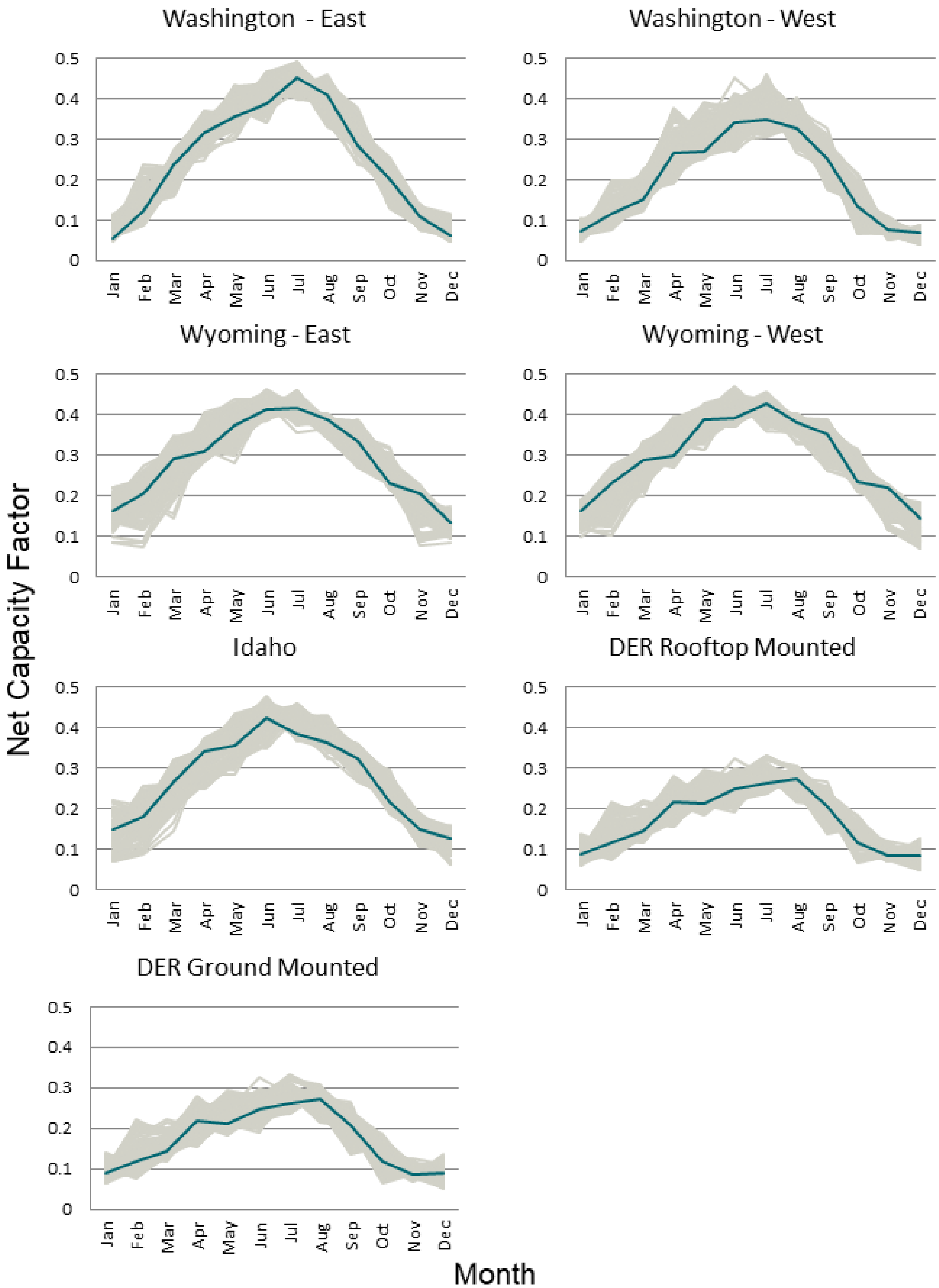
14 SEIA, Solar Market Insight Report, Q4 2020: https://www.seia.org/research-resources/solar-market-insight-report-2021-q4.
15 http://www.gatewaywestproject.com
16 https://nsrdb.nrel.gov

hourly draws was then randomly selected for each site and, after being statistically verified to be representative of the total distribution of 22,000 annual draws for a site, provided to us for modeling.

All capacity factors are provided as AC, where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.3.

We found these updated solar shapes were generally consistent across sites with the solar shapes we used in the 2021 IRP. Finally, a single, most-representative draw is selected from the 250 draws based on nearness to the annual average production of all 250 provided solar profiles. Figure D.4 summarizes the seasonal solar shapes used in the 2023 Electric Report. The grey lines represent the 250 stochastic draws, and the blue line represents the draw selected.

Figure D.4: Seasonal Solar Shapes for Generic Solar Resources



PSE PUGET SOUND ENERGY

2.4. Energy Storage

Energy storage encompasses a wide range of technologies capable of shifting energy usage from one period to another. These technologies could deliver essential benefits to electric utilities and their customers since the electric system currently operates on just-in-time delivery. PSE must perfectly balance generation and load to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, balance supply and demand, provide backup power when primary sources are interrupted, and help integrate intermittent renewable generation. Energy storage technologies are rapidly improving and can benefit all parts of the system – generation, transmission, distribution, and customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

2.4.1. Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable, and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for an extensive storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its performance characteristics, commercial availability, and costs. We chose to model lithium-ion as the generic battery resource in this report because the technology is commercially available, successful projects are operating, and cost estimates and data are available on a spectrum of system configurations and sizes. We received the most energy storage bids for 4-hour lithium-ion battery arrays[17] in response to our 2021 All Source RFPs.[18]

Lithium-ion batteries have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell memory, and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability, and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (e.g., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

At the end of 2019, the U.S. had 1,022 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2019, U.S. utilities also reported 402 MW of existing small-scale storage capacity. [19] Forty-

[17] In an actual RFP solicitation, we would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees, and counterparty credit.

[18] In an actual RFP solicitation, we would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees, and counterparty credit.

[19] U.S. Energy Information Administration, Battery Storage in the United States: An Update on Market Trends, August 2021: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

one percent of this capacity was installed in the commercial sector, 41 percent in the residential sector, 14 percent in the industrial sector, and the remaining 4 percent connected directly to the distribution grid.

2.4.2. Pumped Hydroelectric Energy Storage Technology

Pumped hydroelectric energy storage (PHES, pumped hydro storage, pumped storage, pumped hydro, or PHS) facilities provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over several hours requires a large energy storage capacity, and a device like PHES is well suited for this application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting these projects can take many years. Pumped storage can be designed to provide 6–20 hours of storage with 80 percent roundtrip efficiency.

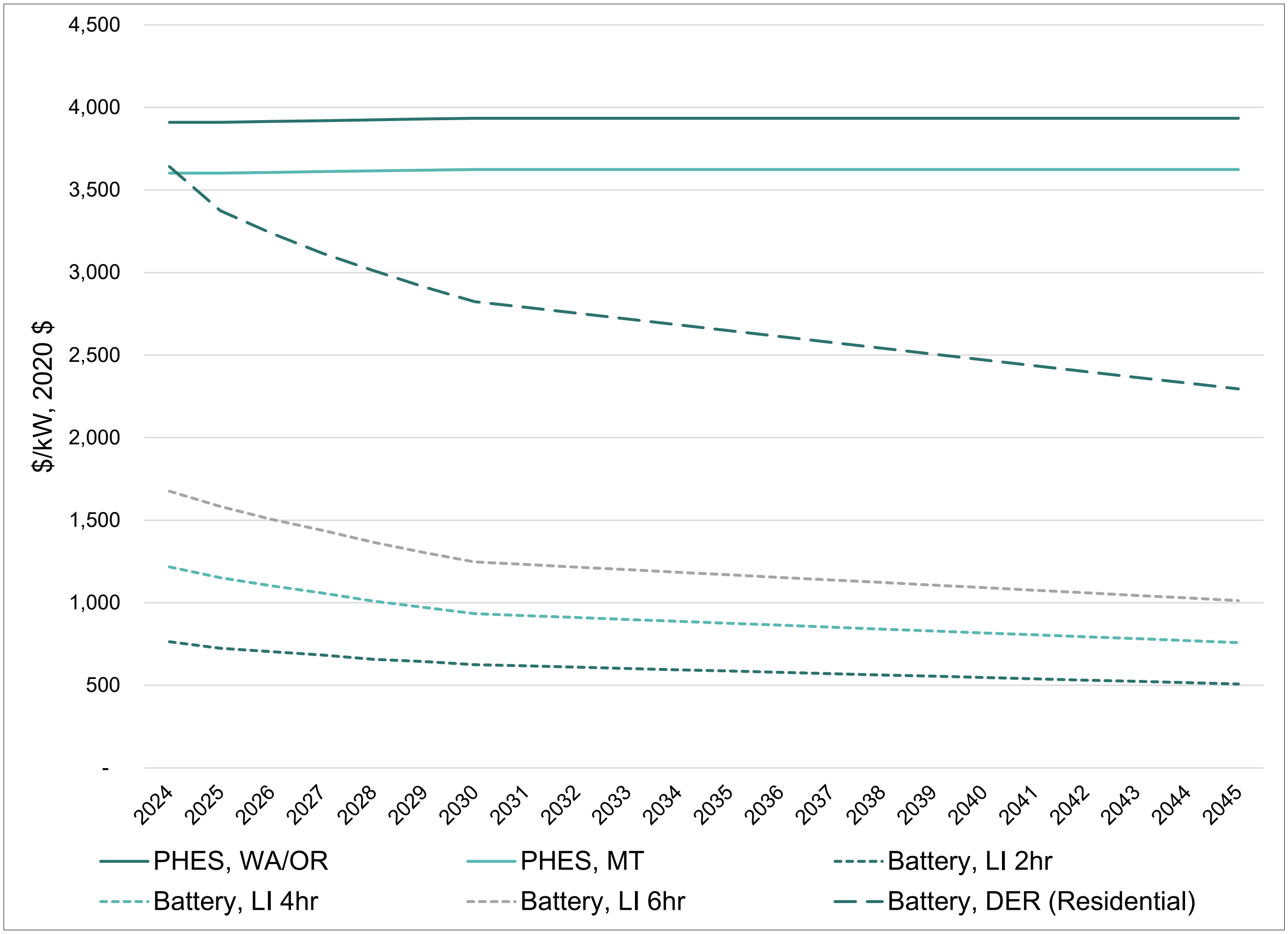
According to the U.S. Department of Energy's most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.9 GW, which represent 93 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[20] At the end of 2019, there were 67 pumped storage projects with a potential capacity of 52.48 GW in the development pipeline. The median project size in the development pipeline is 480 MW, but projects span a wide range of sizes from large projects greater than 3,000 MW to small closed-loop systems of less than 100 MW.[21]

2.4.3. Modeling Assumptions

We modeled six energy storage resources in this report: 100 MW lithium-ion batteries in 2-, 4-, and 6-hour sizes; a smaller 3-hour lithium-ion battery as a distributed energy resource; and two PHES systems, one located in Montana and the other in either Washington or Oregon. Table D.4 summarizes the generic cost assumptions used in the energy storage resource analysis and assumptions used in the 2021 IRP for comparison. Figure D.5 shows the capital cost curves for each energy storage technology through the planning horizon. All costs are in 2020 dollars.

[20] U.S. Energy Information Agency, Annual Electric Generator Report: https://www.energy.gov/sites/prod/files/2021/01/f82/us-hydropower-market-report-full-2021.pdf.
[21] Ibid.

Figure D.5: Capital Cost Curves for Generic Energy Storage Resources



2.5. Hybrid Technologies

Hybrid resources combine two or more resources at one location to take advantage of synergies created through the co-location of the resources. Hybrid resources may combine two generating resources, such as solar and wind, or one generating and one storage resource, such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential, and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. doubled from less than 30 to 80 facilities.[22] Furthermore, 73 percent of the battery storage power planned to come online between 2021 and 2024 will be co-located with solar or wind power plants.[33]

2.5.1. Modeling Assumptions

We are evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 4-hour battery storage and Washington utility solar plus 4-hour battery storage. Additionally, we are evaluating a hybrid configuration of wind and solar generation plus a 4-hour battery storage resource, located in eastern Washington. We configured the hybrid resources in the model so the storage resource can charge using either energy from the generating resource to which it is connected from the market.

Table D.5 presents the operating assumptions for the hybrid systems modeled in this 2023 Electric Report and those modeled in the 2021 IRP for comparison.

3. Thermal Resource Technologies and Assumptions

Combustion turbines (CT) play an essential role in the portfolio, given their versatility and reliability. The following characteristics make combustion turbines a critical tool.

- Proximity: Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- Timeliness: Combustion turbines are dispatchable; we can turn them on to meet loads, unlike intermittent resources that generate power sporadically, such as wind, solar, and run-of-the-river hydropower.
- Versatility: Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

This section describes the thermal resources modeled in this report.

[22] https://www.eia.gov/todayinenergy/detail.php?id=43775.

3.1. Baseload Combustion Turbine Technologies

Baseload combustion turbine plants (combined-cycle combustion turbines or CCCTs) produce energy at a constant rate over long periods at a lower cost than other production facilities available to the system. Baseload combustion turbine plants are typically used to meet some or all of a region's continuous energy demand.

These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for the 2023 Electric Report is 6,624 BTU per kWh. Many plants also feature duct firing. Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. Combined-cycle combustion turbines have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost, and relatively low air emissions. This technology is commercially available. Greenfield development requires approximately three years.

3.2. Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly to meet spikes in need. They also provide the flexibility needed for load following, wind integration, and spinning reserves. We modeled two types of peakers; each brings strengths to the overall portfolio.

3.2.1. Frame Peakers

Frame CT peakers are also known as industrial or heavy-duty CTs and are sometimes referred to as simple cycle combustion turbines (SCCT); these are generally larger in capacity and feature frames, bearings, and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil, or a combination of fuels (dual fuel). The turndown capability of the units is 30 percent. This report's assumed heat rate for frame peakers is 9,904 BTU per kWh. Frame peakers also have slower ramp rates than other peakers at 40 MW per minute for 237 MW facilities. Some can achieve a full load in 21 minutes. Frame CT peakers are commercially available. Greenfield development requires approximately two years.

3.2.2. Reciprocating Peakers

Reciprocating internal combustion engines (recip peakers or RICE) use a reciprocating engine technology evaluated based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher oxygen ratio to fuel, allowing the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size.

The largest commercially available reciprocating engine for electric power generation produces 18 MW, less than the typical frame peaker. Larger-sized generation projects would require more reciprocating units than an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and minimizes the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers. This technology is commercially available. Greenfield development requires approximately three years.

3.3. Modeling Assumptions

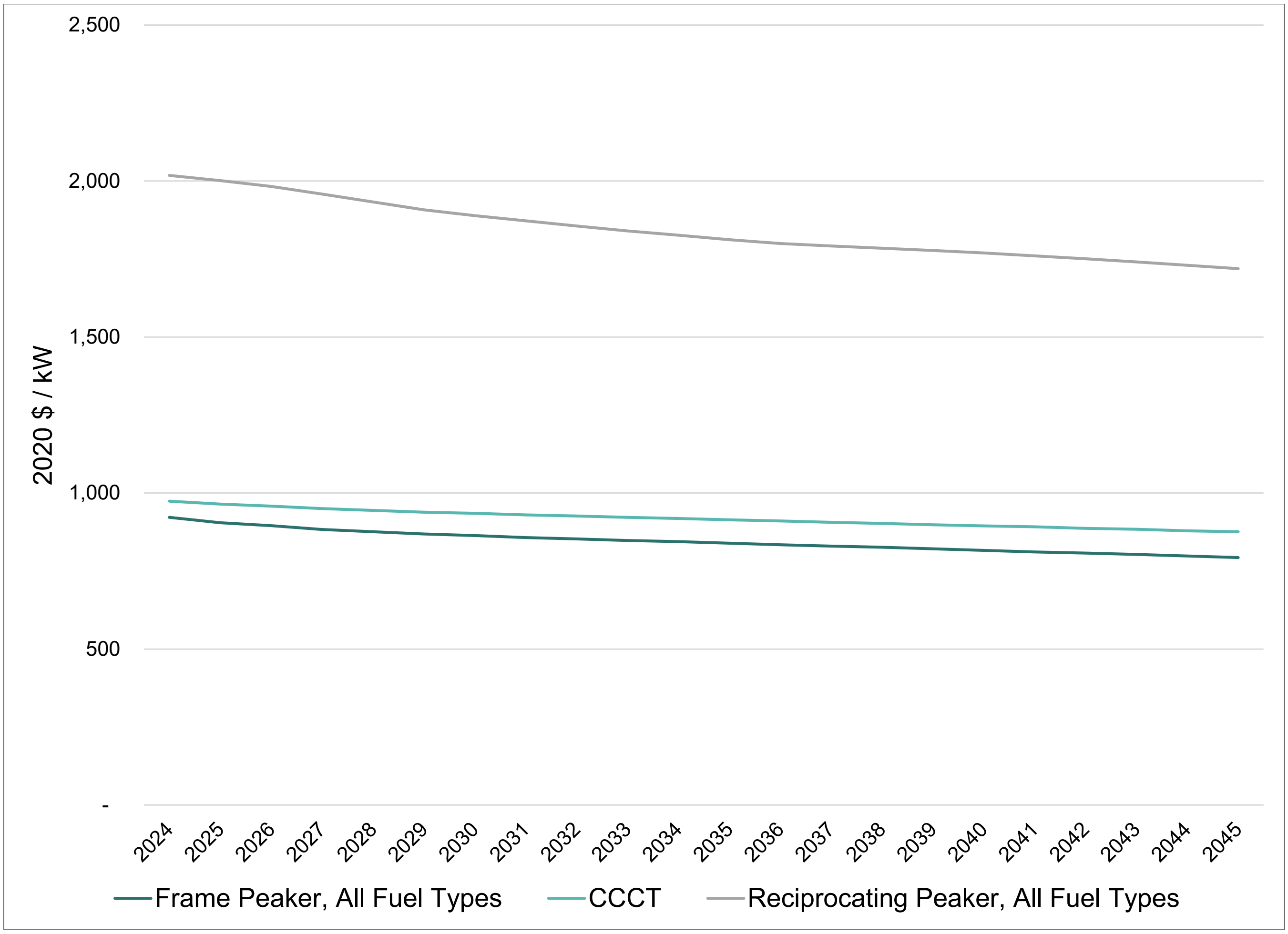
PSE modeled two general types of thermal resources in this 2023 Electric Report: baseload combustion turbine plants (CCCTs), and peaking capacity plants. As PSE moves towards CETA goals, we explored fuel alternatives to natural gas to operate thermal resources and provide non-emitting dispatchable power. Alternative fuels modeled in this 2023 Electric Report include hydrogen and biodiesel.

We modeled a single natural gas-powered CCCT in this report. We modeled three frame-peaking capacity plants: one fueled with natural gas, one with a hydrogen blend, and another with biodiesel. Finally, we modeled two types of reciprocating peaking capacity plants, one fueled with natural gas and the other with a hydrogen blend.

For natural gas-powered CCCT units, we assumed the natural gas supply would be firm year-round at projected incremental gas pipeline firm rates. We assumed natural gas-powered frame peaking units have oil backup, and natural gas supply is available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. We assumed that 20 percent of gas storage is available to baseload CCCT plants and peaking plants and modeled it to accommodate mid-day start-ups or shutdowns. Regardless of fuel type, all thermal units are assumed to be connected to the PSE transmission system and therefore do not incur any direct transmission cost.

The following subsections describe these technologies, including cost assumptions and commercial availability. Figure D.6 presents the capital cost curves for each thermal technology through the planning horizon. Because the fuel type does not affect the overall capital cost of the units, Figure D.6 includes the three different thermal technologies modeled. Table D.6 summarizes the cost and operating assumptions used in the analysis for thermal resources. We also presented assumptions from the 2021 IRP for comparison. All costs are in 2020 dollars.

Figure D.6: Capital Cost Curves for Generic Thermal Resources



3.3.1. Natural Gas Transportation Modeled Costs

Fixed and variable natural gas transportation costs for the combustion turbine plants assumed that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assumed the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's complete fuel requirements. This scenario applies to the baseload CCCT and reciprocating engine without oil.

The analysis assumed that we would meet the gas transportation needs for these resources with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. We assume oil backup with no firm gas transportation for the natural gas frame peaker resources. Table D.7 shows the natural gas transport assumptions for resources without oil backup, and Table D.8 shows natural gas transport assumptions for frame peakers with oil backup.

3.3.2. Green Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and could become an essential energy carrier in the power sector.[23] Hydrogen is abundant in several feedstocks, including water, biomass, fossil fuels, and waste products, but it requires a significant amount of energy to produce elemental hydrogen from these feedstocks. It is common practice to classify hydrogen with color to describe the feedstock and energy source used to produce the hydrogen. Green hydrogen is the most attractive variety of hydrogen in the context of a clean energy transformation. Green hydrogen is typically made from water electrolysis using low- or non-emitting energy sources to power the process.

Green hydrogen has the potential to act as a useful energy carrier to store and deliver low- or no-carbon energy where and when it is needed. When wind and solar generation is plentiful, we can turn on electrolyzers to produce and store hydrogen. When demand is high and renewable generation is unavailable, the stored hydrogen may be combusted in a turbine or electrochemically reacted in a fuel cell to produce electricity. A key advantage green hydrogen has over other storage technologies (e.g., battery energy storage systems or pumped hydroelectric storage) is that hydrogen is stable over long periods, meaning we can store energy monthly instead of hour-to-hour as in other storage systems. This long storage period allows hydrogen to store excess energy in spring and autumn for use in the peak summer and winter seasons.

Despite its potential usefulness, the green hydrogen industry must overcome several obstacles before it can play a significant role in the power sector. Large-scale electrolyzers are an emerging technology with relatively few installations scattered across the globe. Research and development into scaling up production and reducing the costs of electrolyzers are necessary to produce the quantities of hydrogen needed to support the power sector. Powering large installations of electrolyzes will also require a large amount of low- or no-carbon electricity. It is necessary to develop adequate quantities of wind, solar, or other non-emitting generation and the transmission to move the power to the electrolyzers.

After production, hydrogen must be stored and transported. Pipelines are the obvious choice for storage and transportation, but utilities will need dedicated pipelines for high-purity hydrogen storage and transport. Finally, to access the energy stored in hydrogen, existing combustion turbines will require modifications to accommodate the new fuel, or new technologies, such as fuel cells, will need to be researched and developed. These infrastructure-related hurdles add cost and require detailed long-term planning to incorporate green hydrogen into the power system successfully.

The enactment of the 2022 Inflation Reduction Act provides incentives that dramatically reduce the cost barriers to establishing the infrastructure required to make green hydrogen an economically viable energy carrier for the power system. Production Tax Credits (PTCs) from the Inflation Reduction Act could reduce hydrogen prices by up to $3 per kilogram[24], putting green hydrogen price forecasts on par with natural gas prices by the mid-2030s.

[23] https://www.nrel.gov/docs/fy21osti/77610.pdf
[24] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

This development and additional momentum behind green hydrogen from the Department of Energy's Regional Clean Hydrogen Hubs[25] spurred us to include green hydrogen as a fuel source in the 2023 Electric Report. We will likely obtain green hydrogen as part of an offtake agreement from an independent fuel supplier; therefore, hydrogen is modeled simply as a fuel source in the AURORA model.

We assumed several resources are eligible to combust green hydrogen, including a generic frame peaker, a generic reciprocating peaker, and PSE's existing thermal generation fleet. Supply is essential in modeling green hydrogen as a fuel source because it will take time to establish the required infrastructure. Based on our understanding and engagement in the nascent green hydrogen industry, it seems likely the first year significant quantities of hydrogen will become available is 2030. From 2030 forward, we forecast a growing green hydrogen supply in the Pacific Northwest large enough to supply PSE's existing thermal generation fleet. Table D.9 illustrates a trajectory of hydrogen supply using a blend rate with natural gas.

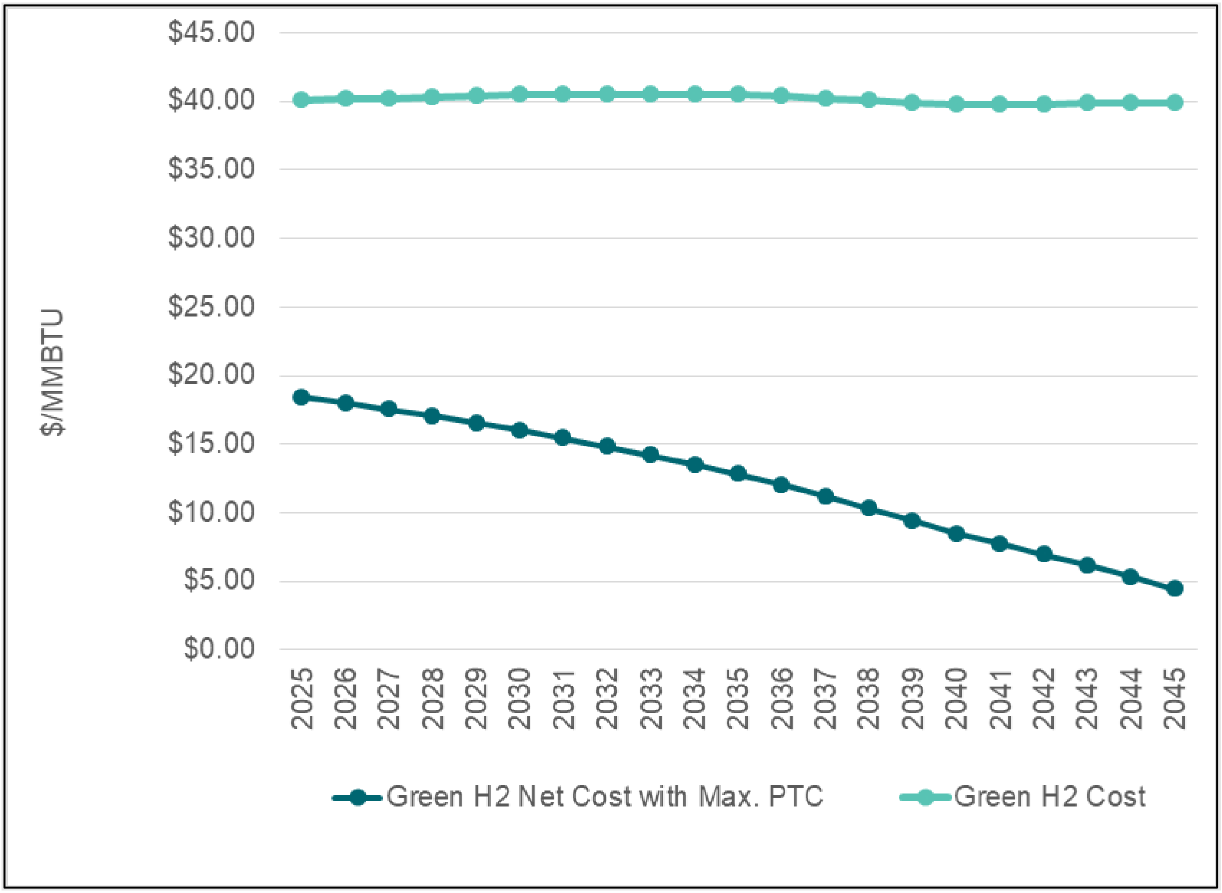
Developing a hydrogen pipeline to the regions of PSE's generation fleet will also constrain green hydrogen fuel supply. To reflect this constraint in the model, we limited access to green hydrogen for PSE's existing thermal fleet to a schedule based on our estimate of probable hydrogen production regions and subsequent expansion of pipelines from those regions. Table D.10 reflects the timeline we forecast a hydrogen pipeline may be available at new and existing thermal resources.

Price is the final consideration required to model green hydrogen. We developed a hydrogen price forecast based on assumptions from the E3 Pacific Northwest report[26] and industry consultations. We also applied the maximum PTC benefit to the green hydrogen price, reflecting the incentives expected for green hydrogen development in the Pacific Northwest. Figure D.7 illustrates the price forecast for green hydrogen in the AURORA model.

[25] https://www.energy.gov/oced/regional-clean-hydrogen-hubs

[26] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Figure D.7: Green Hydrogen Price Forecast



3.3.3. Biodiesel

Washington State defines biodiesel as a renewable resource under section 2 (34) of CETA. To be considered renewable, biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests. Biodiesel is chemically like petroleum diesel but is derived from waste cooking oil or dedicated crops. According to the U.S. Energy Information Administration, two facilities in Washington State make biodiesel, which together can manufacture upward of 100 million gallons of biodiesel a year.

Biodiesel may become a viable fuel supply for combustion turbines to provide peak capacity in the future. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At total capacity, a 237 MW frame peaker would require approximately 25,000 gallons of biodiesel per hour. At this fuel feed rate, a facility would require about 1.2 million gallons of biodiesel storage to fire for a 48-hour peak event continuously. The existing Washington State biodiesel production capacity of 107 million gallons per year in 2022[27] could plausibly supply several combustion turbines intended to supply reliable power during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low-hydroelectric conditions.

We explored biodiesel used in simple-cycle combustion turbines in this 2023 Electric Report. We included a generic frame peaker with biodiesel as the primary fuel in the AURORA long-term capacity expansion analysis. We

[27] https://www.eia.gov/biofuels/biodiesel/capacity/

configured this biodiesel peaker to purchase a fixed seven-day biodiesel supply during critical peak hours each year. This limited fuel supply equals an approximate 2 percent capacity factor for the biodiesel peaker. We estimated biodiesel prices at $33.13/MMBTU based on the Department of Energy Alternative Fuel Price Report, January 2022.[28]

4. New Resource Technologies and Assumptions

Puget Sound Energy considered modeling several emerging technologies, particularly energy storage technologies. However, due to accurate and reliable data availability, advanced nuclear small modular reactors (SMRs) are the only new technology considered in this 2023 Electric Report. Advanced nuclear SMR resource technology, cost, and operating assumptions are provided below. Other emerging technologies are discussed further in the following section, Resource Technologies Not Modeled.

4.1. Advanced Nuclear Small Modular Reactors

Nuclear power is considered a source of non-emitting electric generation under section 2 (28) of CETA [RCW 19.405.020.[29] This configuration has the distinct advantage over traditional nuclear resources of being far more flexible in terms of scaling energy output and therefore has the potential for use as a dispatchable resource rather than being utilized strictly as baseload capacity. In practice, this resource could be either entirely dispatchable or have a portion dedicated to baseload and a part held in reserve to cover peak events. In addition to the flexibility benefits, this resource is a non-variable resource making it highly reliable and non-emitting. This combination of dispatchability, reliability, and emission-free production could make this a very attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

An advanced nuclear SMR plant consists of a cluster of nuclear reactors that share land and infrastructure while retaining the ability to activate and deactivate independently. Each module consists of a single reactor, similar in size and technology to the units employed on nuclear submarines, with an output ranging from 40 to 80 MWs. An entire SMR plant may consist of four to twelve modules. Advances in nuclear engineering in fuel containment and cooling systems, including the ability to dry cool a system even in total water loss, make SMR systems much safer than traditional large-scale nuclear plants.

An SMR plant is far more cost-effective than a traditional nuclear plant because they require a fraction of the land footprint, and the modules are small and can be prefabricated off-site and shipped to the desired location. Although SMR plants are a relatively new application of nuclear technology in utility-scale electric generation, this application appears to be entering commercial availability, with several companies bringing this application to market. Those companies include X-energy, which currently has a contract to install an SMR facility at the Hanford Nuclear site for Energy Northwest, and NuScale, also constructing an SMR facility in Idaho Falls in partnership with the Idaho National Laboratory.

[28] https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_january_2022.pdf
[29] RCW 19.405.020

There is not a significant amount of literature on SMR waste disposal. However, one influential study whose authors include a former chairperson of the U.S. Nuclear Regulatory Commission[30] suggests that although SMRs use less fuel than traditional nuclear plants, they could generate significantly more waste due to increased irradiation of specific reactor components. Although the current practice for existing nuclear facilities is to store waste on-site in casks built to contain the waste material, the cited paper recommends that a portion of waste material would ideally be treated before disposal in a geologic repository with engineered barriers for shielding material from the environment. It suggests this could significantly raise disposal-related costs.

Greenfield development of a new SMR facility requires approximately four years.

4.1.1. Modeling Assumptions

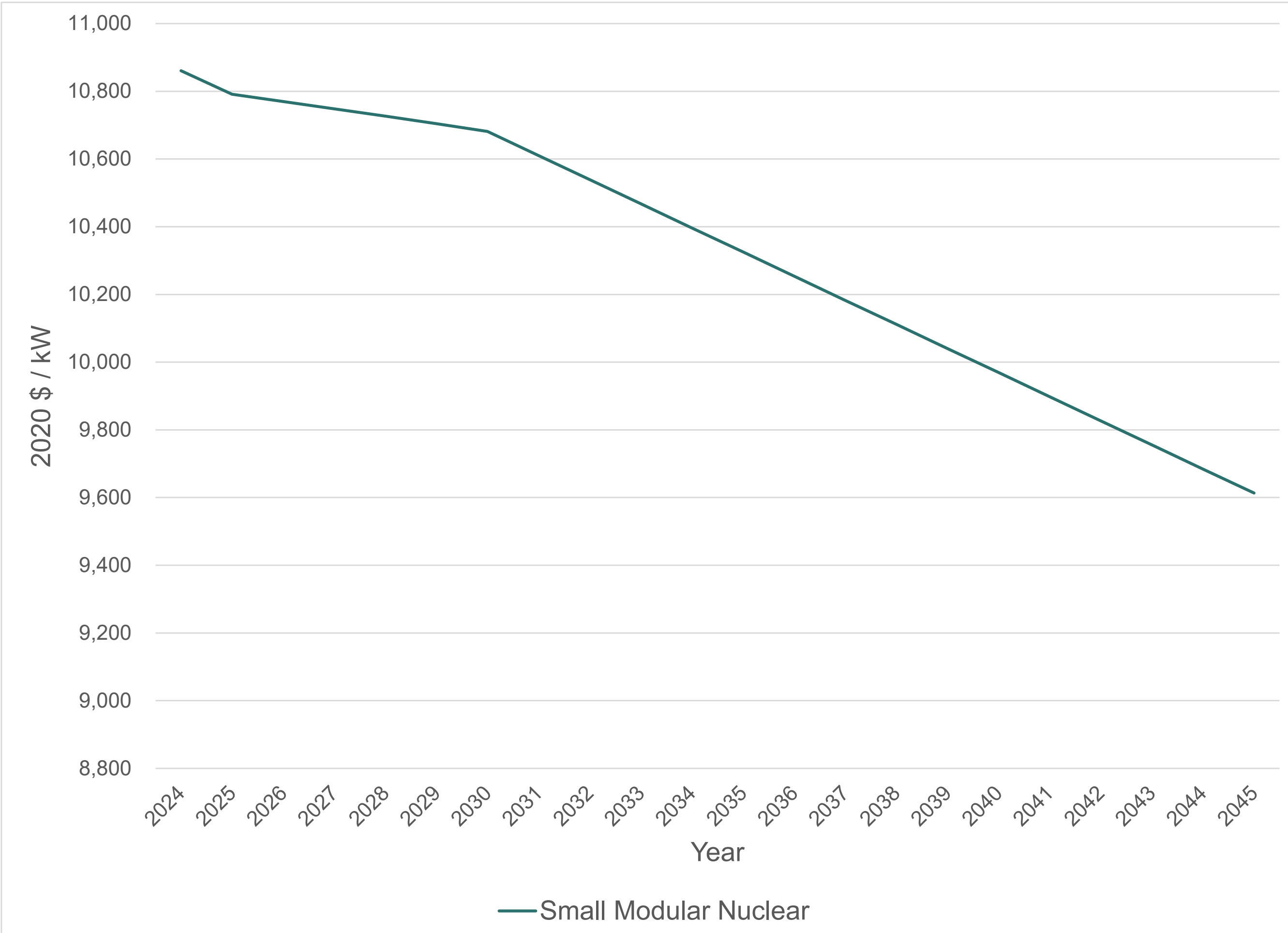
For the first time, we modeled an SMR plant in this report. We modeled an SMR configuration consisting of 12 modules with an output of 50 MWs each, totaling 600 MWs of capacity and a heat rate of 10046 BTU per kWh. This configuration is consistent with information provided by the EIA's Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies.[31]

Figure D.8 presents the capital cost curves for SMR plants through the planning horizon. Table D.11 summarizes the cost and operating assumptions used in the analysis for SMR resources. All costs are in 2020 dollars. Because this technology is not commercially available at the time of this analysis, we constrained the model to allow the first year of SMR resource builds in 2030.

30 https://www.pnas.org/doi/10.1073/pnas.2111833119

31 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Figure D.8: Capital Cost Curve for Advanced Nuclear Small Modular Reactors



5. Resource Technologies Not Modeled

This section discusses the resource technologies PSE considered but did not model in this 2023 Electric Report. Some technologies, such as coal, are becoming obsolete in a clean energy landscape; others PSE determined to be either geographically or technologically infeasible for PSE's system at this time.

5.1. Renewable Resources Not Modeled

Several renewable resource technologies were not modeled in this 2023 Electric Report because 1) the technologies are in the early development stages and cost and operational data is lacking; 2) the technology is not feasible within geographic proximity to PSE; and/or 3) the technology has not been built to operate on a large, utility scale. Several of these technologies are summarized in this section.

5.1.1. Solar Thermal Plants

Solar thermal plants focus the direct irradiance of the sun to generate heat that produces steam, which in turn drives a conventional turbine generator. Two general types are used or in development today, trough-based and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun on a horizontal pipe carrying water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A transfer fluid collects and transfers the heat to make steam. Thermal solar plants have been operating successfully in California since the 1980s.[32]

5.1.2. Fuel Cells

Fuel cells combine fuel and oxygen to create electricity, heat, water, and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can power equipment, buildings, or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures, and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. Fuel cell systems must be cost-competitive with and perform as well as traditional power technologies over the system's life[33] to be economical.

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the U.S. Department of Energy's report *State of the States: Fuel Cells in America 2017*,[34] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $7,224 per kW.[35]

5.1.3. Geothermal

Geothermal generation technologies use the natural heat under the earth's surface to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

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32 SEIA, Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf.

33 U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.

34 U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf.

35 https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

- Dry steam plants use hydrothermal steam from the earth to power turbines directly. Dry steam plants were the first type of geothermal power generation technology developed.[36]
- Flash steam plants operate similarly to dry steam plants but use low-pressure tanks to vaporize hydrothermal liquids into steam. This technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius) like dry steam plants.[37]
- Binary-cycle power plants can use lower-temperature hydrothermal fluids to transfer energy through a heat exchanger to a liquid with a lower boiling point. This system is an entirely closed loop; no steam emissions from the hydrothermal fluids are released. Most new geothermal installations will likely be binary-cycle systems due to the limited emissions and greater potential sites with lower temperatures.[38]
- Enhanced geothermal or hot dry rock (HDR) technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[39]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower-than-anticipated production from the geothermal resource. In 2021, geothermal power plants in seven states produced about 16 GWh, equal to 0.4 percent of total U.S. utility-scale electricity generation.[40] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[41] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and Idaho's 15.8 MW Raft River plant.

The EIA estimates capital costs for geothermal resources are approximately $2,521/MW.[42] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that can be built in the Northwest Power Pool region, where most of the proposed sites are located. Site-specific factors, including resource size, depth, and temperature, can significantly affect costs.

5.1.4. Waste-to-energy Technologies

Converting wastes to energy is a way to capture the inherent energy locked in wastes. Generally, these plants take one of the following forms.

- Waste combustion facilities: These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. Waste combustion is a well-established technology, with 75 plants operating in the United States, representing 2,534 MW in generating capacity. According to the U.S. EPA's website, only one new facility has opened since 1995. However, some existing facilities have expanded their capacity to convert more waste into electricity.[43]

[36] http://energy.gov/eere/geothermal/electricity-generation
[37] Ibid
[38] Ibid
[39] http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
[40] U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php.
[41] U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036.
[42] U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020.
[43] U.S. Environmental Protection Agency website. http://energyrecoverycouncil.org/wp-content/uploads/2019/10/ERC-2018-directory.pdf.

- Waste thermal processing facilities include gasification, pyrolysis, and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, the facility generates syngas, which can be combusted for heat or to produce electricity. Several pilot facilities once operated in the United States, but only a few remain.
- Landfill gas and municipal wastewater treatment facilities: Most landfills in the United States collect methane from decomposing landfill waste. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both processes produce low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then fuel a boiler for heat recovery or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's website, as of June 2022, there are 541 operational landfill gas energy projects in the United States.[44]

Washington's RPS initially included landfill gas as a qualifying renewable energy resource but excluded municipal solid waste. The passage of Washington State Senate Bill (ESSB) 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities — the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant, and the Emerald City facility — use landfill gas for electric generation in Washington State; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and can produce a maximum capacity of 36.5 MW.[45] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and can produce up to 22 MW of electric capacity.[46] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[47] Puget Sound Energy purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which we discuss in Appendix C. The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies gas to meet pipeline natural gas quality; the gas is sold to PSE rather than used to generate electricity.

Few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion

44 U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, June 2022.

45 Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.

46 Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy, January 2019.

47 BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

facilities, the output is typically more stable because we can more easily control the amount of input waste and heat content.

5.1.5. Wave and Tidal

We can use the natural movement of water to generate energy through the flow of tides or the rise and fall of waves.

Tidal generation technology uses tidal flow to spin rotors that turn a generator. Two significant plant layouts exist: barrages, which use artificial or natural dam structures to accelerate the flow through a small area, and in-stream turbines, placed in natural channels. France's Rance Tidal Power barrage system was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia, and South Korea have smaller tidal power installations.[48] Also worth noting is the planned 398 MW MeyGen Tidal Energy Project in Scotland, which, if completed, would be the largest tidal generation facility in the world. The project's first phase, a 6 MW demonstration array, began operating in April 2018.[49] The project is designed to be constructed in multiple phases, with phase 2B completed in September 2020.[50]

Wave generation technology uses the rise and fall of waves to drive hydraulic systems and fueling generators. Technologies tested include floating devices and bottom-mounted devices. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[51] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's website, the 20 kW Azura device, developed by EHL Group and Northwest Energy Innovations, is the nation's first grid-connected wave energy converter device.[52]

Since mid-2013, several significant wave and tidal projects and programs have slowed, stalled, or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting, and the early stage of the technology's development. The FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After operators obtain permits, they must conduct studies of the site's water resources and aquatic habitat before they install test equipment.

[48] U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
[49] https://tethys.pnnl.gov/project-sites/meygen-tidal-energy-project-phase-i
[50] Ibid
[51] CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
[52] The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

There are three tidal demonstration projects in various stages of development in the United States located on Roosevelt Island (New York), Western Passage (Maine), and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[53] Several years ago, Tacoma Power considered and abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years, and their production volumes are limited, so costs remain high, and the durability of the equipment over time is uncertain.

5.2. Energy Storage Not Modeled

Several energy storage technologies are still in development, or are still new enough that reliable cost and operational data are not yet available. Some of these technologies are described in this section.

5.2.1. Flow Batteries

Flow batteries are rechargeable batteries that are charged by two chemical components dissolved in liquids contained within the system. A membrane separates the two components, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can offer the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time.

In 2016, Avista Utilities installed the first large-scale[54] U.S. flow battery storage system in Washington; in 2017, utilities in Washington and California installed two additional flow battery facilities. Approximately 70 MW and 250 MWh of flow batteries have been deployed worldwide, almost all in medium- to large-scale projects.[55] Flow batteries have limited market penetration at this time.

5.2.2. Liquid Air Energy Storage

Liquid Air Energy Storage (LAES) technology involves supercooling air into a liquid state for storage in insulated tanks. As the air is reheated and expands back into a gaseous state, the pressure created moves a turbine. The LAES technology utilizes a relatively small footprint and has no other special siting requirements, giving the technology geographical flexibility and the potential to be deployed as a distributed resource. This technology can store energy for long periods with little degradation and provide long-duration discharge to the grid. Finally, additional insulated tanks are the main component required to scale up the size and capacity of a LAES system, making this technology modular, flexible, and inexpensive compared to other storage alternatives.

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[53] The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project, October 2014.

[54] Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.

[55] IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029.

The LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage, and expansion of pressurized gasses. Although the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester, England. The pilot plant can produce 5 MW/15MWh of storage capacity. Furthermore, the company is constructing a 50 MW LAES resource in Vermont and up to 2 GWh storage in Spain. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[56]

5.2.3. Hydrogen Energy Storage

Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, passing a current through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity and for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer demonstration project, powered by the University of California at Irvine on-campus solar electric system. SoCalGas also partnered with NREL to install the nation's first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site's hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[57]

5.2.4. Solid Gravity Storage

Solid gravity storage is an emerging alternative to PHES. Several companies are pioneering different forms of solid gravity storage technology, which can involve raising and lowering large bricks using a crane or elevator system or moving a rail car loaded with weight along an inclined rail track.

Only a handful of prototypes or demonstration projects are in operation now. The company Energy Vault has constructed a modular crane kinetic storage demonstration unit in Switzerland, storing 20-80 MWh of energy and delivering 4–8 MW of continuous power to the grid.[58] The European company, Gravitricity, has built an above-

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[56] Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.
[57] Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive.
[58] Energy Vault website: https://www.energyvault.com/gravity.

ground prototype of their underground kinetic storage technology, which is currently operating in Scotland.[59] The rail kinetic storage company, Advanced Rail Energy Storage, has been contracted to build a facility in Nevada which will supplement the CAISO grid but is still in the planning phase.[60] However, these technologies are still emerging, and publicly available and reliable data on operating parameters are costs are unavailable at this time.

5.3. Thermal Resources Not Modeled

Laws, practical obstacles, and cost constrain other potential thermal resource alternatives. Long-term coal-fired generation is not a resource alternative because RCW 80.80[61] precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New traditional nuclear generation is neither practical nor feasible.

5.3.1. Coal

Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

New coal-fired generation is not a resource alternative for PSE because RCW 80.80[61] sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[62] With current technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard. Carbon capture and sequestration technology are not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA passed on May 7, 2019, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

5.3.2. Traditional Nuclear

Capital and operating costs for large-scale nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy, and waste disposal risks over other baseload resources.

59 Gravitricity website: https://gravitricity.com.
60 S&P Global IQ Pro Platform. Available at: https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home.
61 RCW 80.80
62 To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

There is little reliable data on recent U.S. nuclear developments from which we can make reasonable and supportable cost estimates. The construction cost and schedule track record for nuclear plants built in the U.S. in the 1980s, 1990s, and 2000s have been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to lengthy delays, and interest rate increases have resulted in high financing charges. The Fukushima disaster in 2011 also motivated changes to technical and regulatory requirements and contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution, and the bankruptcy of a major nuclear supplier all lead to significant uncertainty. These factors make a full-scale nuclear plant an unwise and unnecessary risk for PSE.

5.3.3. Aeroderivative Peakers

Aeroderivative Combustion Turbines (Aero) combustion turbines are a mature technology. However, suppliers continually bring new aeroderivative features and designs to market. These turbines can be fueled by natural gas, oil, renewable natural gas, hydrogen, biodiesel, or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another critical difference between aero and frame units is size. Aero CTs are typically smaller, from 5 to 100 MW each. This small scale allows for modularity but also tends to reduce economies of scale.

The Aero peakers are higher cost than the Frame peakers and smaller and more modular than the frame peakers. We modeled the Aero peakers for several IRPs in a row but never selected them as a cost-effective resource given the higher cost than the frame peakers. Given that we are already modeling a large frame peaker and the smaller Recip Peaker to show how a smaller, more modular unit can benefit the portfolio, we felt there was enough diversity in the resource alternatives and removed the Aero peakers as an option.

This technology is commercially available. Greenfield development requires approximately three years.

6. Tables

Table D.1: Biomass Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Assumptions	2023 Electric Report Assumptions
Nameplate Capacity (MW)	15	15
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--
Capacity Credit (ELCC), Summer (%)	--	--
Operating Reserves (%)	3	3
Capacity Factor (%)	85	85
Capital Cost ($/kW)	7,093	4,822
O&M Fixed ($/kW-yr)	207	151
O&M Variable ($/MWh)	6	6
Land Area (acres/MW)	6 – 8	6 - 8
Degradation (%/year)	--	--
Location	WA	WA
Fixed Transmission ($/kW-yr)	22.2	23
Variable Transmission ($/MWh)	0.00	0.26
Loss Factor to PSE (%)	1.9	1.9
Heat Rate – Baseload (HHV) (Btu/kWh)	14,599	14,599
NOx (lbs/MMBtu)	0.03	0.03
SO2 (lbs/MMBtu)	0.03	0.03
CO2 (lbs/MMBtu)	213	213
First Year Available	2024	2024[i]
Economic Life (Years)	30	30
Greenfield Dev. & Const. Lead-time (Years)	3.3	3.3

Notes:

i. Given the 2021 All Source RFP process, it is possible some of these resources will be in process of development before the beginning of this analysis, and will therefore be available as soon as 2024.

Table D.2: Wind Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Nameplate Capacity (MW)	100	100	200	400	400	100	100	100	100	100	100
Winter Peak Capacity (MW)	--	--	--	--	--	32	34	13	36	48	182
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	48	18	22 / 30	24	40 / 28	32	34	13	36	12	46
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	--	41	13	5	23	17	34
Operating Reserves (%)	3	3	3	3	3	3	3	3	3	3	3
Capacity Factor (%)	35	37	44 / 40	33	33	42	41	37	41 / 48	15	46 / 36
Capital Cost ($/kW)	5,609	1,806	1,806	1,806	1,806	4,728	1,730	1,464	2,472	1,772	1,772
O&M Fixed[ii] ($/kW-yr)	110	41	41	41	4	71	42	42	42	42	42
O&M Variable ($/MWh)	0	0	0	0	110 / 0	0	0	0	0	0	0
Land Area (acres/MW)	--	48.2	48.2	48.2	48.2	--	48.2	48.2	48.2	48.2	48.2
Degradation (%/year)	0	0	0	0	0	0	0	0	0	0	0
Fixed Transmission[iii] ($/kW-yr)	33	33	50	158	231 / 211	31	62	31	59	61	97
Variable Transmission ($/MWh)	10	10	10	10	10	0.26	0.26	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9	1.9	4.6	4.6	4.6	1.9	1.9	1.9	4.6	6.9	6.9
First Year Available	2030	2024	2024	2026	2026	2030	2024[iv]	2024[iv]	2024[iv]	2026	2026

Parameter	2021 IRP Values					2023 Electric Report Values					
	Offshore	WA	MT East / Central	ID	WY East / West	Offshore	BC	WA	MT East / Central	ID	WY East / West
Economic Life (Years)	30	30	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (Years)	3	2	3	2	2	3	2	2	2	2	2

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches, with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.

ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. This table shows the 2023 value.

iii. The Wyoming wind and solar rates apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for wind and solar resources from Wyoming decreased to $67 and $64/kW-year, respectively, assuming the Gateway West transmission line is completed in 2030.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and be available as soon as 2024.

Table D.3: Solar Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values				2023 Electric Report Values			
	WA (East / West)	ID	WY (East / West)	DER Rooftop / Ground-mounted WA West	WA (East / West)	ID	WY (East / West)	DER Rooftop & Ground-mounted WA West
Nameplate Capacity (MW)	100 / 50	400	400	300 / 50	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	--	4	32	42	0
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	4 / 1	3	6	2 / 1	4	8	11	4
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	--	54	38	29	28
Operating Reserves (%)	3	3	3	3	3	3	3	--
Capacity Factor (%)	24 / 16	26	27 / 28	16	25 / 20	27	29 / 30	17
Capital Cost ($/kW)	1,675	1,675	1,675	4,389 / 3,568	1,230	1,537	1,537	2,287
O&M Fixed[ii] ($/kW-yr)	22	22	22	0	19	19	19	25
O&M Variable ($/MWh)	0	0	0	0	0	0	0	0
Land Area (acres/MW)	5 – 7	5 – 7	5 – 7	-- / 5 – 7	5 – 7	5 – 7	5 - 7	--
Degradation (%/year)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	--
Fixed Transmission[iii] ($/kW-yr)	30 / 8	155	228 / 208	0	28	58	94	5
Variable Transmission ($/MWh)	10	10	10	0	0.26	0.26	0.26	0.26
Loss Factor to PSE (%)	1.9 / --	4.6	4.6	--	1.9	6.9	6.9	--
First Year Available	2024	2026	2026	2024	2024[iv]	2026	2026	2024
Economic Life (Years)	30	30	30	30	30	30	30	30
Greenfield Lead-time (Years)	1	1	1	1	1	1	1	--

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy.

ii. Fixed operations and maintenance for wind, solar, battery storage, and hybrid resources change over time. The 2023 value is in this table.

iii. Rates for WY solar apply to 2024–2030 and assume the use of Idaho Power Company transmission infrastructure. Between 2031 and 2045, fixed transmission rates for solar from WY go down to $64/kW-year, assuming the Gateway West transmission line is completed in 2030.

iv. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.4: Generic Energy Storage Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	PHES	BESS		PHES		BESS			
	Closed Loop (8-hour)	Li-Ion 2-hour	Li-Ion 4-hour	Closed Loop (8-hour) WA, OR	Closed Loop (8-hour) MT	Li-Ion 2-hour	Li-Ion 4-hour	Li-Ion 6-hour	DER Batteries (3-hour)
Nameplate Capacity (MW)	25	25	25	100	100	100	100	100	5
Winter Peak Capacity (MW)	--	--	--	99	99	85	96	98	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter[i] (%)	37.2	12.4	24.8	99	99	85	96	98	--
Capacity Credit (ELCC), Summer[i] (%)	--	--	--	99	99	90	97	98	--
Operating Reserves (%)	3	3	3	3	3	3	3	3	3
Capital Cost ($/kW)	2,656	1,172	2,074	3,910	3,602	805	1,310	1,819	3,923
O&M Fixed ($/kW-year)	16	23	32	18	18	20	33	45	98
O&M Variable ($/MWh)	0.00	0.00	0.00	0.51	0.51	0.00	0.00	0.00	0.00
Forced Outage Rate (%)	--	--	--	1	1	2	2	2	0.1
Degradation (%/year)	0	--	--	(ii)	(ii)	(iv)	(iv)	(iv)	2.2
Operating Range (%)	147-500[iii] MW	2	2	147-500[iii] MW	147-500[iii] MW	2	2	2	10
R/T Efficiency (%)	80	82	87	80	80	86	87	88	87
Discharge at Nominal Power (Hours)	8	2	4	8	8	2	4	6	3
Maximum Storage (MWh)	200	50	100	800	800	200	400	600	15
Fixed Transmission ($/kW-year)	22	0	0	23	50	0	0	0	0
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.26	0.26	0.00	0.00	0.00	0.00
First Year Available	2028	2023	2023	2029	2029	2024[v]	2024[v]	2024[v]	2024
Economic Life2 (Years)	30	30	30	40	40	30	30	30	30
Greenfield Dev. & Const. Leadtime (years)	5–8	1	1	5–8	5–8	1	1	1	0.5

Notes:

i. We modeled ELCCs for the 2023 Electric Report in tranches with values that changed based on the number of new builds. The first tranche is in this table. For more information on ELCC tranches and saturation effects please reference Appendix L: Resource Adequacy..

ii. PHES degradation is close to zero.

iii. The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
iv. Fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life.
v. Given the 2021 All Source RFP process, it is possible that some of these resources will be in development before the beginning of this analysis and will be available as soon as 2024.

Table D.5: Hybrid Generic Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Progress Report Values		
	MT Wind + PHES	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Battery (WA)	Solar + Battery (WA)	Wind + Solar + Battery (WA)
Nameplate Capacity (MW)	300	125	125	150	150	250
Winter Peak Capacity (MW)	--	--	--	101	77	83
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	54	24	14	67	51	33
Capacity Credit (ELCC), Summer (%)	--	--	--	53	87	54
Operating Reserves (%)	3	3	3	3	3	3
Capacity Factor (%)	44	37	24	37	25	62
Capital Cost ($/kW)	4,016	2,680	2,563	(i)	(i)	(i)
O&M Fixed ($/kW-year)	57	64	46	(i)	(i)	(i)
O&M Variable ($/MWh)	0	0	0	0	0	0
Land Area (acres/MW)	48.2	48.2	5-7	48.2	48.2	48.2
Degradation (%/year)	0	0.5	0.5	(ii)	(iii)	(ii, iii)
Fixed Transmission ($/kW-year)	50	33	30	31	28	36
Variable Transmission ($/MWh)	10	10	10	0.26	0.26	0.26
Loss Factor to PSE (%)	4.6	1.9	1.9	1.9	1.9	1.9
First Year Available	2028	2024	2024	2024[iv]	2024[iv]	2024[iv]
Economic Life (Years)	30	30	30	30	30	30
Greenfield Dev. & Const. Lead time (years)	5 – 8	2	1	2	1	2
Operating Range (%)	147-500 MW	2	2	2	2	2
R/T Efficiency (%)	80	82	82	87	87	87
Discharge at Nominal Power (Hours)	8	2	2	4	4	4

Notes:

i. We input individual capital costs and fixed operations and maintenance values for each element of the hybrid resource into the AURORA model. The individual hybrid component capital costs are adjusted (discounted) from stand-alone counterparts to account for savings in installation, grid connection, and system balance.

ii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for wind is 0 percent.

iii. Battery fixed operations and maintenance costs include augmentation ensuring MW and MWh rating for project life; degradation for solar is 0.5 percent.

iv. Given the 2021 All Source RFP process, some of these resources may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.6: Generic Combustion Turbine Resource Assumptions, 2020 $

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Nameplate Capacity (MW)	225	336	219	225	336	219	225	219	225
Winter Capacity Primary (23º F) (MW)	237	348	219	237	348	219	237	219	237
Incremental Capacity DF (23º F) (MW)	--	19	--	--	19	--	--	--	--
Capacity Credit (Effective Load Carrying Capacity [ELCC]), Winter (%)	--	--	--	96	96	84	96	84	96
Capacity Credit (ELCC), Summer (%)	--	--	--	98	96	92	98	92	98
Capital Cost ($/kW)	948	1,255	1,671	944	987	2,045	944	2,045	944
O&M Fixed ($/kW-year)	8	13	6	16	23	15	16	15	10
Flexibility ($/kW-year)	--	--	--	-10	-5	-28	-10	-5	-10
O&M Variable ($/MWh)	7.86	3.32	7.05	1.02	6.16	1.16	1.02	1.16	1.02
Start-up Costs ($/Start)	7.86	3.32	7.05	11,729[ii]	0	0	11,729[ii]	0	11,729[ii]
Operating Reserves (%)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Forced Outage Rate (%)	2.4	3.9	3.3	2.4	3.9	3.3	2.4	3.3	2.4
Heat Rate — Baseload (HHV) (Btu/kWh)	9,904	6,624	8,445	9,904	6,624	8,445	9,904	8,445	9,904
Heat Rate — Turndown (HHV) (Btu/kWh)	15,794	7,988	11,288	15,794	7,988	11,288	15,794	11,288	15,794
Heat Rate — DF (Btu/kWh)	--	8,867	--	--	8,867	--	--	--	--
Min Capacity (%)	30	38	30	30	38	30	30	30	30
Start Time (hot) (minutes)	21	45	5	21	45	5	21	5	21
Start Time (warm) (minutes)	21	60	5	21	60	5	21	5	21

Parameter	2021 IRP Values			2023 Electric Report Values					
	Frame Peaker	CCCT	Recip Peaker	Frame Peaker[1]	CCCT[i]	Recip Peaker[i]	Frame Peaker Blend H_2	Recip Peaker Blend H_2	Frame Peaker Biodiesel
Start Time (cold) (minutes)	21	150	5	21	150	5	21	5	21
Start-up fuel (hot) (MMBtu)	366	839	69	366	839	69	366	69	366
Start-0up fuel (warm) (MMBtu)	366	1,119	69	366	1,119	69	366	69	366
Start Fuel Amount (warm) (MMBtu/MW/Start)	1.544	3.214	0.317	1.54	3.21	0.32	1.54	0.32	1.54
Start-up fuel (cold) (MMBtu)	366	2,797	69	366	2,797	69	366	69	366
Ramp Rate (MW/minutes)	40	40	16	40	40	16	40	16	40
Fixed Ga Transport ($/Dth/Day)	0.00	0.25	0.25	0.00	0.27	0.27	0.00	0.00	0.00
Fixed Gas Transport ($/kW-year)	0.00	14.67	18.70	0.00	15.41	19.65	0.00	20	0.00
Variable Gas Transport ($/MMBtu)	0.04	0.06	0.06	0.04	0.06	0.06	0.04	0.06	0.06
Fixed Transmission ($/kW-year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable Transmission ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO2 - Natural Gas (lbs./MMBtu)	118	118	118	118	118	118	118 declining to 0	118 declining to 0	0
NOx - Natural Gas (lbs./MMBtu)	0.004	0.008	0.029	0.004	0.008	0.029	0.004	0.029	0.004
First Year Available	2025	2025	2025	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]	2024[iii]
Economic Life (years)	30	30	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead-time (years)	1.8	2.7	2.3	1.8	2.7	2.3	1.8	2.3	1.8

Notes:

i. Technology assumptions: the frame peaker is a 1x0 F-Class Dual Fuel; the CCCT is a 1x1 F-Class; and the reciprocal peaker is a 12x0 18 MW class reciprocating internal combustion engine.

ii. The startup cost adder of $52.13/start/MW, from the 2020 CAISO default values, is applied to the frame peaker.

iii. Given the 2021 All Source RFP process, some frame peakers may be in development before the beginning of this analysis and therefore be available as soon as 2024.

Table D.7: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup — 100% Sumas on NWP + 100% Station 2 on West Coast

Pipeline/Resource	Fixed Demand ($/Dth/day)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Expansion[i]	0.6900	0.0083	0.0013	1.41	3.85
Westcoast Expansion[ii]	0.7476	0.0551	--	--	--
Basis Gain[iii]	(0.8139)	--	--	2.71	3.85
Gas Storage[iv]	0.0767	--	--	2.00	3.85
Total	**0.7004**	**0.0634**	**0.0013**	**6.12**	**3.85**

Notes:

i. Estimated NWP Sumas to PSE Expansion.

ii. Estimated West coast Expansion Fixed Demand.

iii. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses, and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day, and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852 percent applies to the natural gas price.

iv. We based storage requirements on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Table D.8: N Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup — No Firm Gas Pipeline

Pipeline / Resource	Fixed Demand ($/Dth/day)	Weighted Average Variable Demand ($/Dth)	Variable Commodity ($/Dth)	ACA Charge ($/Dth)	Fuel Use (%)	Utility Taxes (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41	3.82
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41**	**3.82**

Table D.9: Green Hydrogen Blend Rate

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2025	0
2030	30
2035	50

Year	Green Hydrogen Blend Rate (%, H_2 energy / total energy)
2040	70
2045	100

Table D.10: Resource Access to a Green Hydrogen Fuel Supply

Resource	Access Year
New generic resources	2030
Frederickson 1, 2, CC	2030
Whitehorn 1, 2	2030
Ferndale	2030
Encogen	2035
Fredonia 1,2,3,4	2035
Mint Farm	2035
Sumas	2040
Goldendale	2045

Table D.11: Advanced Nuclear Small Modular Reactor Resource Assumptions, 2020 $

Parameter	Assumptions
Nameplate Capacity (MW)	50
Capacity Credit, (Effective Load Carrying Capacity) (%)	100%
Operating Reserves (%)	3%
Capital Cost ($/KW)	$10,930
O&M Fixed ($/KW-yr)	$114
O&M Variable ($/MWh)	$3

Parameter	Assumptions
Forced Outage Rate (%)	10%
Heat Rate – Baseload (HHV) (Btu/KWh)	10,046
Heat Rate – Turndown (HHV) (Btu/KWh)	12,500
Min Capacity (%)	30%
Start Time (minutes)	60
Ramp Rate (MW/min)	30
Location	PSE
Fixed Transmission ($/KW-yr)	$0
Variable Transmission ($/MWh)	$0
First Year Available	2028
Economic Life (Years)	30
Greenfield Dev. & Const. Lead Time (years)	4

CONSERVATION POTENTIAL AND DEMAND RESPONSE ASSESSMENTS

APPENDIX E

PUGET SOUND ENERGY

Contents

1. Introduction 1
2. Treatment of Demand-side Resource Alternatives 2
3. Distribution Efficiency 3

1. Introduction

We analyzed demand-side resource (DSR) alternatives in conservation potential and demand response assessments (CPA) to develop 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 electric or natural gas portfolio cost. This analysis identifies the cost-effective level of DSR to include in the portfolio.

We included the following demand-side resource alternatives in the CPA, which The Cadmus Group performed for this 2023 Electric Progress Report (2023 Electric Report) on behalf of 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. We included only those in place at the time of the CPA study.
- **Demand response (DR):** Demand response resources comprise flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **Distributed generation:** Distributed generation refers to small-scale electricity generators close to the source of the customer's load on the customer's side of the utility meter. This resource alternative includes combined heat and power (CHP) and rooftop solar.[1]
- **Distribution efficiency (DE):** Distribution efficiency involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction reduces the voltage on distribution circuits to reduce energy consumption, so many appliances and motors can perform while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **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, lighting, and appliance upgrades.
- **Generation efficiency:**[2] This involves energy efficiency improvements at the facilities that house PSE generating plant equipment and where the loads that serve the facility are drawn directly from the generator, not the grid. These are parasitic loads — specific measures target HVAC, lighting, plug loads, and building envelope end-uses.

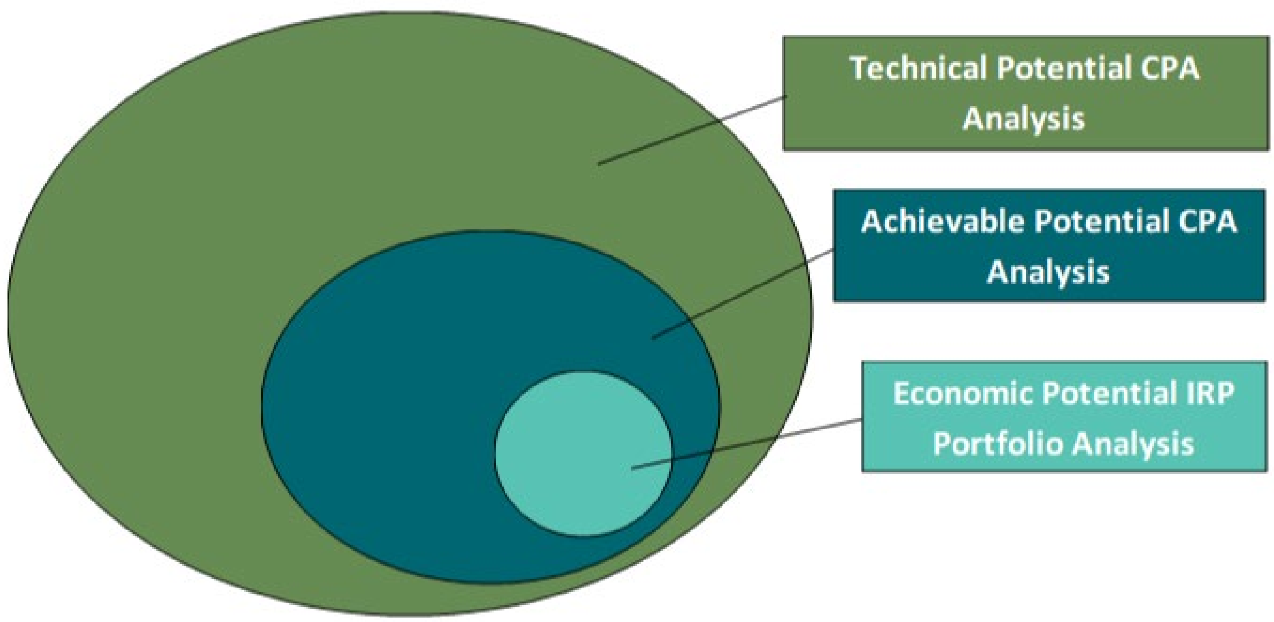
[1] In this report distributed solar photovoltaic (PV) is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the total resource cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

[2] Generation efficiency potential was studied in prior planning cycles, was relatively small and found to be not cost-effective and hence this resource is not included in this report.

2. Treatment of Demand-side Resource Alternatives

The CPA performed by the Cadmus Group on behalf of PSE develops two levels of demand-side resource conservation potential: technical potential and achievable technical potential. The 2023 Electric Report portfolio analysis then identifies the third level, economic potential. Figure E.1 shows the relationship between the technical, achievable, and economic conservation potentials.

Figure E.1: Relationship between Technical Achievable and Economic Potential

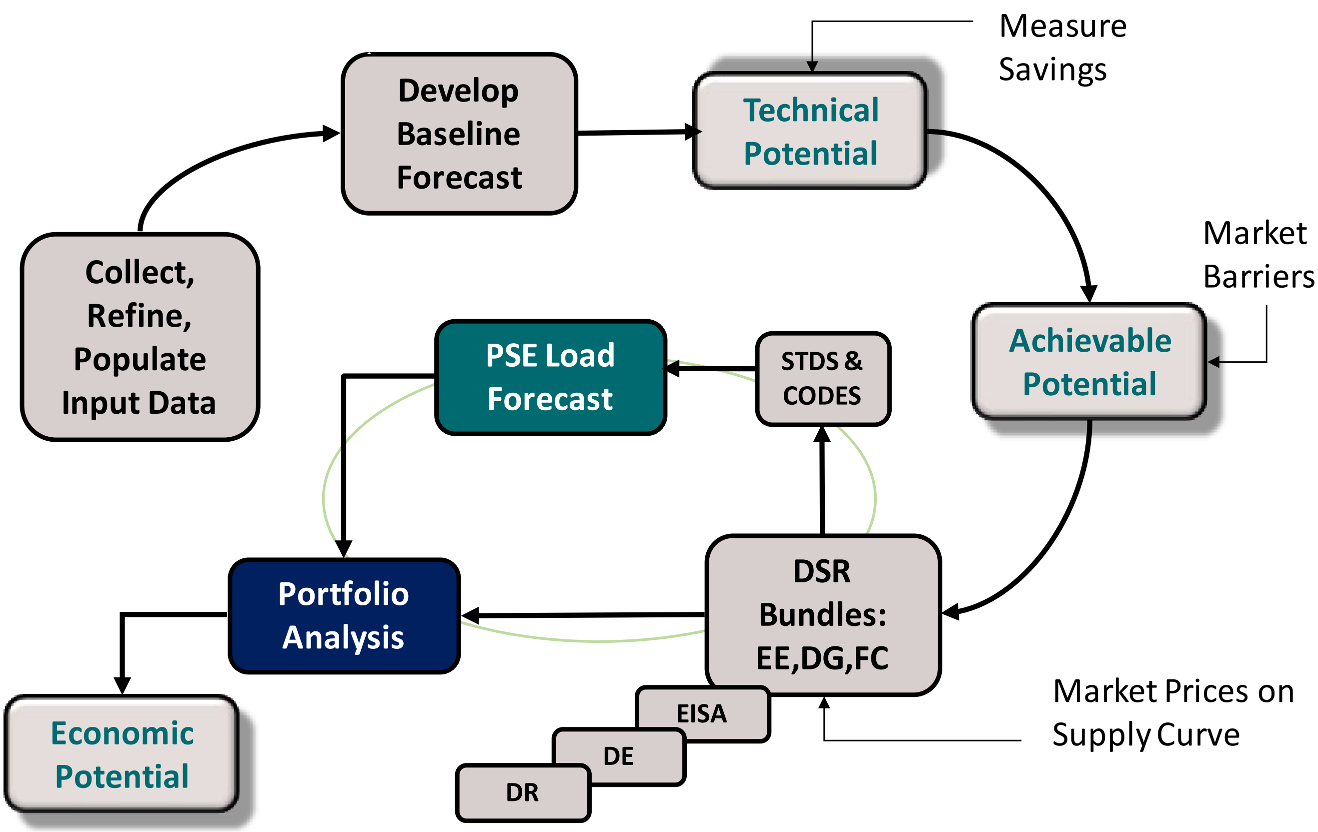


First, the CPA screened each measure for technical potential. This screen assumed we could capture all energy- and demand-saving opportunities regardless of cost or market barriers, which ensured the model surveyed the full spectrum of technologies, load impacts, and markets.

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 report, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

We combined the measures into bundles based on levelized cost in the third step. This step produced a conservation supply cost curve in the portfolio optimization analysis to identify the bundles' economic potential (cost-effectiveness).

Figure E.2 Methodology to Assess Demand-side Resource Potential in the 2023 Electric Progress Report



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

This appendix contains the conservation potential assessment report for the 2023 Electric Progress Report. It includes a detailed discussion of all the demand-side resource types mentioned, except for distribution efficiency, which PSE developed and discussed here.

3. Distribution Efficiency

We updated plans for distribution efficiency in this report to reflect 1) changes in technology required to maintain power quality and stability as the role of distribution efficiency grows and 2) the increase in amounts of the distributed generation entering the delivery system.

The original conservation voltage reduction (CVR) program we implemented in 2012–2013 utilized advanced metering infrastructure (AMI) meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. We expect to complete the rollout in 2023. In the meantime, selected substations that received the AMI upgrade can participate in the current CVR program.

We also have a second technology upgrade planned. The current CVR program is a static form of CVR that cannot react to compensate for changes in the distribution system produced by distributed resources such as battery storage, solar generation, and day ahead (DA) schemes. Because the static system cannot react and adjust to changing conditions in the distribution system, we are investing in automated distribution management system (ADMS) technology that we can program to automatically detect and anticipate changing conditions on the system. This technology allows the system to react fast enough to prevent damaging customers' power quality.

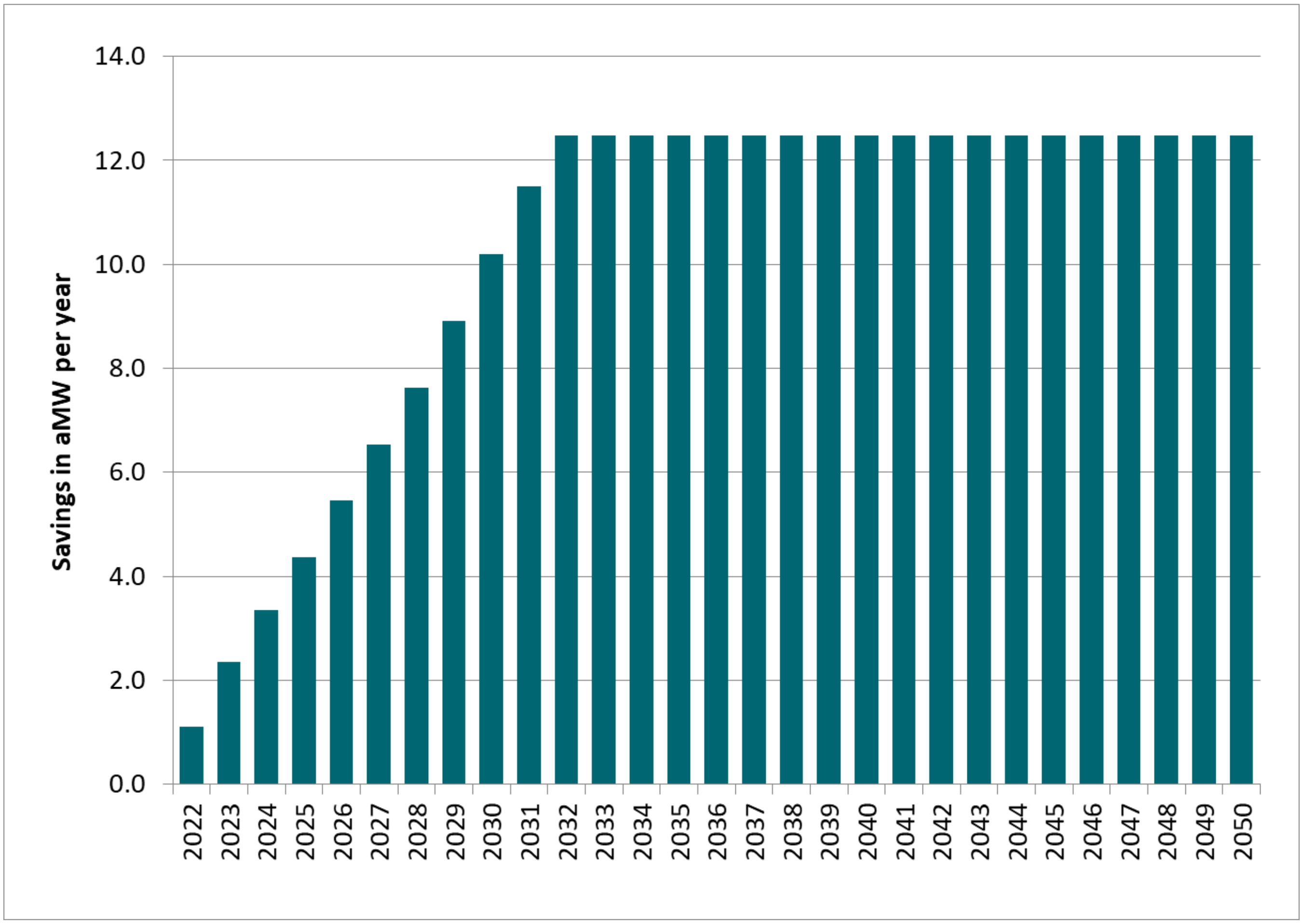
Once we implement the AMI and ADMS technologies, we will have the operational control system necessary to transition the CVR program to total Volt-Var Optimization (VVO). With its analytics and control intelligence, the ADMS will leverage AMI data at the end of line to dynamically optimize power delivery within the distribution network, minimize losses, and conserve energy. This system builds on dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR but relies on similar principles.

We expect to complete the AMI rollout in 2023 and the ADMS software platform in 2026. We expect to begin piloting VVO in 2025. From 2023–2025, we will continue implementing the current static line drop compensation (LDC) CVR, but we may continue to encounter complications and risks due to changes in the distribution system that are already occurring.

Figure E.3 presents the expected cumulative savings throughout the 2023 Electric Progress Report planning horizon from CRV and VVO.

Eligible Substations: We started the current CVR program based on a study completed in 2007. That study identified approximately 160 substation banks with at least 50 percent residential customers as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations.

Figure E.3: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)



CADMUS

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

Conservation Potential Assessment

Demand Response Assessment

Distributed Solar Assessment

August 31, 2022

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Table of Contents

Executive Summary ... 1

Scope of the Analysis and Approach ... 2

Energy Efficiency and Combined Heat and Power ... 2

Demand Response ... 3

Rooftop Solar PV ... 3

Summary of Results ... 4

Energy Efficiency ... 5

Combined Heat and Power Potential ... 9

Demand Response Potential ... 10

Rooftop Solar PV Potential ... 11

Incorporating Demand-Side Resources into PSE's Integrated Resources Plan ... 12

Organization of This Report ... 13

Chapter 1. Energy Efficiency and Combined Heat and Power Potential ... 14

Energy Efficiency Potential ... 14

Considerations and Limitations ... 18

Energy Efficiency Potential - Overview ... 19

Energy Efficiency Potential - Residential Sector ... 20

Energy Efficiency Potential - Commercial Sector ... 24

Energy Efficiency Potential - Industrial Sector ... 26

Impacts of Codes and Standards ... 28

Non-Energy Impacts ... 28

Combined Heat and Power Potential ... 29

Combined Heat and Power Technical Potential Results ... 32

Combined Heat and Power Achievable Technical Potential Results ... 33

Combined Heat and Power Levelized Cost Results ... 35

Chapter 2. Demand Response Potential ... 37

Overview of Technical and Achievable Technical Potential Approach ... 37

Technical Potential Approach ... 37

Achievable Technical Potential Approach ... 38

Levelized Costs Calculations ... 38

Supply Curve Development 39
Demand Response Potential 39
Scope of Analysis 39
Summary of Resource Potential 40
Chapter 3. Rooftop Solar PV Potential 44
Overview of Technical and Achievable Technical Potential Approach 44
Technical Potential Approach 44
Achievable Technical Potential Approach 45
Methodology 45
NREL dGen Model 46
Approach for Technical Potential 46
Approach for Vulnerable Populations 47
Approach for Multifamily Potential 47
Approach for Renters 47
Approach for Small Systems 47
Model Inputs 47
Rooftop Solar PV Potential 49
Technical Potential Results 49
Achievable Technical Potential Results 49
Chapter 4. Energy Efficiency Methodology Details 51
Market Segmentation 52
Energy Conservation Measure Characterization 53
Non-Energy Impacts 55
Measure Data Sources 57
Incorporating Federal Standards and State and Local Codes and Policies 58
Treatment of Federal Standards 60
Additional Codes and Standards Considerations 61
Adapting Measures from PSE Business Cases, RTF, and Draft *2021 Power Plan* 62
Baseline End-Use Load Forecast Development 64
Derivation of End-Use Consumption 65
PSE Forecast Climate Change Alignment 67
Conservation Potential Estimation 67

Technical Potential 68
Achievable Technical Potential 69
Integrated Resource Plan Input Development 70
Glossary of Terms 74
Appendix A. Detailed Demand Response Potential Results and Input Assumptions by Product Option A-1

Tables

Table 1. Summary of Energy Savings and Demand Reduction Potential, Cumulative 2050 4
Table 2. Energy Efficiency by Sector, Cumulative 2050 5
Table 3. Energy Efficiency Comparison of 2023 CPA and 2021 CPA, 24-Year Potential 8
Table 4. Combined Heat and Power Achievable Technical Potential Summary, Cumulative 2050 9
Table 5. Combined Heat and Power Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA 10
Table 6. Demand Response Potential by Program, 2050 10
Table 7. Demand Response Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA, Winter 10
Table 8. Solar PV Achievable Technical Potential (Nameplate) Comparison of 2023 CPA and 2021 CPA 12
Table 9. Electric 27-Year Cumulative Energy Efficiency Potential 19
Table 10. Top Residential Electric Savings Measures 22
Table 11. Percentage of Vulnerable Population Customers in Each County 23
Table 12. Residential Vulnerable Population Customer Potential - Electric 24
Table 13. Top Commercial Electric Savings Measures 26
Table 14. Top Industrial Electric Savings Measures 27
Table 15. Data Sources for Combined Heat and Power Technical Potential 30
Table 16. Data Sources for Combined Heat and Power Achievable Technical Potential 31
Table 17. Market Penetration for 2012–2016 31
Table 18. Combined Heat and Power Levelized Cost Data Sources 32
Table 19. Combined Heat and Power Technical Potential by Sector and Fuel (Cumulative in 2050) 33
Table 20. Combined Heat and Power 2050 Cumulative Achievable Technical Potential Equipment Installations 34
Table 21. Combined Heat and Power 2050 Cumulative Achievable Technical Potential at Generator 34

Table 22. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Winter 2050 ... 40

Table 23. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Summer 2050 ... 41

Table 24. Baseline Model Inputs ... 48

Table 25. Rooftop Solar PV Technical Potential ... 49

Table 26. Rooftop Solar PV Achievable Technical Potential ... 50

Table 27. Segments Modeled ... 53

Table 28. List of Non-Energy Impacts ... 56

Table 29. Methodological Hierarchy for Non-Energy Impact Data Inclusion ... 57

Table 30. Key Measure Data Sources ... 57

Table 31. Electric Federal and State Standards Considered ... 60

Table 32. Residential Council Modeled HVAC FMY to TMY Ratios ... 67

Table 33. Electric Levelized Cost Bundles ... 71

Table 34. Levelized Cost Components ... 72

Table A-1. Residential Direct Load Control Water Heat Input Assumptions ... A-2

Table A-2. Winter Residential Direct Load Control Water Heat Achievable Technical Potential and Levelized Cost ... A-4

Table A-3. Residential Direct Load Control HVAC Input Assumptions ... A-6

Table A-4. Winter Residential Direct Load Control HVAC Achievable Technical Potential and Levelized Cost ... A-9

Table A-5. Residential Direct Load Control Electric Vehicle Supply Equipment Input Assumptions ... A-10

Table A-6. Winter Residential Direct Load Control Electric Vehicle Supply Equipment Achievable Technical Potential and Levelized Cost ... A-11

Table A-7. Commercial Direct Load Control HVAC Input Assumptions ... A-12

Table A-8. Winter Commercial Direct Load Control HVAC Achievable Technical Potential and Levelized Cost ... A-15

Table A-9. Commercial and Industrial Curtailment Input Assumptions ... A-16

Table A-10. Winter Commercial and Industrial Curtailment Achievable Technical Potential and Levelized Cost ... A-18

Table A-11. Residential Critical Peak Pricing Input Assumptions ... A-19

Table A-12. Winter Residential Critical Peak Pricing Achievable Technical Potential and Levelized Cost by Product Option ... A-20

Table A-13. Commercial Critical Peak Pricing Input Assumptions.. A-21

Table A-14. Winter Commercial Critical Peak Pricing Achievable Technical Potential and Levelized Cost A-22

Table A-15. Industrial Critical Peak Pricing Input Assumptions.. A-23

Table A-16. Winter Industrial Critical Peak Pricing Achievable Technical Potential and Levelized Cost A-24

Figures

Figure 1. Achievable Technical Potential Forecast, Cumulative 2024–2050...5

Figure 2. Energy Efficiency Achievable Technical Heat Map by Zip Code — Energy (MWh), Cumulative 2050 6

Figure 3. Electric Supply Curve, Cumulative 27-Year Achievable Technical Potential 13

Figure 4. Types of Energy Efficiency Potential...15

Figure 5. Conservation Potential Assessment Methodology 17

Figure 6. 27-Year Achievable Technical Potential by Sector 19

Figure 7. Electric 27-Year Cumulative Energy Efficiency Supply Curve 20

Figure 8. Electric Energy Efficiency Potential Forecast...20

Figure 9. Residential Electric Achievable Technical Potential by Segment 21

Figure 10. Residential Electric Achievable Technical Potential by End Use 21

Figure 11. Residential Electric Achievable Technical Potential Forecast by End Use................................22

Figure 12. Residential Market Rate (Left) and Residential Vulnerable Population (Right) Heat Map........23

Figure 13. Residential Achievable Technical Potential Forecast for Vulnerable Populations.....................24

Figure 14. Commercial Electric Achievable Technical Potential by Segment..25

Figure 15. Commercial Electric Achievable Technical Potential by End Use...25

Figure 16. Commercial Electric Achievable Technical Potential Forecast...26

Figure 17. Industrial Electric Achievable Technical Potential Forecast 27

Figure 18. Electric Codes and Standards Potential Forecast 28

Figure 19. Non-Energy Impacts on Levelized Cost, Cumulative 2050 Achievable Technical Potential.......29

Figure 20. Percentage of 2050 Combined Heat and Power Technical Potential by Technology (in aMW) 33

Figure 21. Combined Heat and Power Cumulative Achievable Technical Potential by Year at Generation (aMW)..35

Figure 22. Breakout of Combined Heat and Power 2050 Cumulative Achievable Technical Potential 35

Figure 23. Nominal Levelized Cost by Technology and Installation Year 36

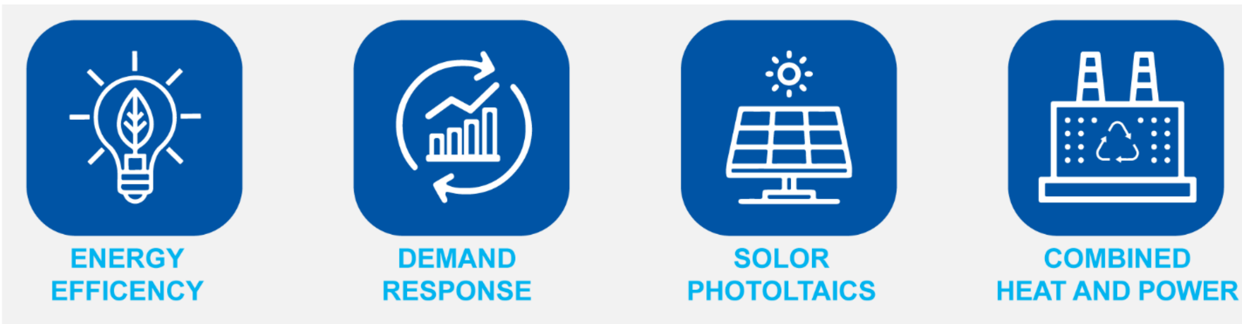
Figure 24. Demand Response Achievable Technical Potential Supply Curve by Product Option, Winter..42
Figure 25. Demand Response Achievable Technical Potential Forecast by Program, Winter....................42
Figure 26. Demand Response Achievable Technical Potential Forecast by Program, Summer..................43
Figure 27. Types of Estimated Potential...44
Figure 28. Rooftop Solar PV Achievable Technical Potential - Nameplate 50
Figure 29. Overview of Energy Efficiency Methodology 52
Figure 30. Types of Energy Efficiency Potential...68
Figure 31. Lost Opportunity Council Ramp Rates...70
Figure 32. Illustration of Capital and Reinstallation Cost Treatment 72

Acronyms and Abbreviations

Acronym	Definition
AMI	Advanced metering infrastructure
aMW	Average megawatt
ATB	Annual technology baseline
BPA	Bonneville Power Administration
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CAC	Central air conditioner
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CETA	Clean Energy Transformation Act
CHP	Combined heat and power
Council	Northwest Power and Conservation Council
CPA	Conservation potential assessment
CPP	Critical peak pricing
dGen	Distributed Generation Market Demand
DLC	Direct load control
DRAC	Demand Response Advisory Committee
DRPA	Demand response potential assessment
ECM	Energy conservation measure
EISA	Energy Independence and Security Act
ERWH	Electric resistance water heater
EUL	Effective useful life
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
FMY	Future meteorological year
FTE	Full-time equivalent
GEWH	Grid-enabled water heater
HPWH	Heat pump water heater
IRP	Integrated Resource Plan
NEEA	Northwest Energy Efficiency Alliance
NEI	Non-energy impact
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PGE	Portland General Electric
PSE	Puget Sound Energy
PV	Photovoltaic
RBSA	Residential Building Stock Assessment
RCS	*Residential Characteristics Study*
RCW	Revised Code of Washington
RTF	Regional Technical Forum
SME	Subject matter expert
T&D	Transmission and distribution
TMY	Typical meteorological year
TOU	Time of use
TRC	Total resource cost
UES	Unit energy savings
WAC	Washington Administrative Code
WSEC	Washington State Energy Code

Executive Summary

This report presents the results of an independent assessment of the technical and achievable technical potential for electric 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, demand response, and distributed generation (including solar photovoltaics [PV] and combined heat and power [CHP]).



The results of this assessment will provide direct inputs into PSE's 2023 IRP and 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 STATUTORY REQUIREMENTS of Chapter 194-37 of the Washington Administrative Code (WAC), Energy Independence Act. The WAC requires that PSE identify all achievable, cost-effective, conservation potential for the upcoming ten years. PSE's public biennial conservation target should be no less than the *pro rata* share of conservation potential over the first ten years.[1] This study will help inform PSE targets.

SUPPORTS PSE'S COMPLIANCE with Washington State's Clean Energy Transformation Act (CETA), passed as Senate Bill 5116 in April 2019 (RCW 19.405),[2] by informing PSE's energy efficiency and demand response short- and long-term targets.

INFORMS PSE'S NEAR-TERM INTERIM TARGETS for its Clean Energy Implementation Plan as required by the CETA.

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

For this study, Cadmus incorporated 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

[1] Washington State Legislature. Energy Independence Act. Washington Administrative Code Chapter 194-37

[2] Revised Code of Washington. Accessed August 24, 2022. "Chapter 19.405 RCW, Washington Clean Energy Transformation Act." https://app.leg.wa.gov/RCW/default.aspx?cite=19.405

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 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). For the electric study Cadmus also estimated demand response potential to align with the Council's demand response methodology and to provide PSE with the data necessary to meet Washington State's CETA requirements, and we estimated distributed generation potential (including solar PV and CHP).

New in this CPA compared to prior CPAs, the electric 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 natural gas energy efficiency potential (including transport customers and natural gas–to-electric impacts) can be found in a separate companion report titled *Comprehensive Assessment of Demand-Side Natural Gas Resource Potential (2024–2050)*.

Scope of the Analysis and Approach

This section outlines the scope of the energy efficiency, CHP, demand response, and rooftop solar PV potential analyses while briefly explaining the approach used for each analysis.

Energy Efficiency and Combined Heat and Power

Cadmus estimated the technical and achievable technical potential for more than 420 unique electric 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 electric energy savings and peak demand reduction for each energy efficiency measure using an end use–based model. The assessment considers multiple sectors, segments, and vintages; distinguishes between lost opportunity and retrofit (discretionary) measures; and accounts 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 electric 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 covered under the *Energy Efficiency Potential* section of *Chapter 1. Energy Efficiency and Combined Heat and Power Potential*.

For the CHP analysis, Cadmus identified potential generation from nonrenewable and renewable CHP technologies in large commercial and industrial (C&I) facilities. We estimated CHP technical potential using generation and applicability data for reciprocating engines, microturbines, natural gas turbines, industrial biomass, and biogas. We determined achievable technical potential for these technologies using American Council for an Energy-Efficient Economy CHP favorability data[3] and an analysis of the recent U.S. Department of Energy "CHP Installation Database."[4] A detailed discussion of the CHP potential is covered under the *Combined Heat and Power Potential* section of *Chapter 1. Energy Efficiency and Combined Heat and Power Potential*.

Demand Response

Demand response programmatic options seek to help reduce peak demand during system emergencies or periods of extreme market prices and to promote improved system reliability. Cadmus focused on program options grouped into four areas: residential direct load control (DLC); commercial DLC; C&I curtailment; and price-based demand response. These options cover major customer segments and end uses in PSE's service territory and include residential DLC for space and water heating and space cooling, residential DLC electric vehicle supply equipment (EVSE), commercial DLC for space heating and cooling, C&I load curtailment, and residential and C&I critical peak pricing.

To estimate demand response potentials, Cadmus applied a hybrid top-down and bottom-up approach that began by using utility system loads, disaggregated into sector, segment, and applicable end uses. For each program, Cadmus first assessed potential impacts at the end-use level, then we aggregated these impacts to obtain estimates of technical potentials. With this approach, we applied market factors (such as the likelihood of program and event participation) to technical potentials to obtain estimates of market potentials. A detailed discussion of the demand response potential is covered under *Chapter 2. Demand Response Potential.*

Rooftop Solar PV

Cadmus' used the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand (dGen) tool[5] to estimate technical and achievable market potential. We incorporated available data to assess solar PV potential for residential and commercial buildings, such as the power density of solar PV arrays and assumed future improvements in the efficiency of solar PV technology. NREL's dGen tool accounts for continuously changing economic conditions, such as declining technology costs,

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3 American Council for an Energy-Efficient Economy. n.d. "State-by-State CHP Favorability Index Estimate." http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

4 U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power and Microgrid Installation Databases." https://doe.icfwebservices.com/chpdb/

5 National Renewable Energy Laboratory. Accessed August 24, 2022. "Distributed Generation Market Demand Model." https://www.nrel.gov/analysis/dgen/

changing tax credits, and electric rates over the study period. Cadmus developed the adoption diffusion-curve parameters based on PSE's historical adoption as well as PSE's near-term 2022 and 2023 projections. A detailed discussion of the rooftop solar PV potential is covered under *Chapter 3. Rooftop Solar PV Potential.*

Summary of Results

Table 1 shows the 27-year technical and achievable technical potential for each resource considered in this study. Electric demand-side resources represent nearly 556 average megawatts (aMW) of achievable technical potential and produce approximately 1,155 MW of winter peak savings. Energy efficiency has the highest energy-savings potential, with 548 aMW of cumulative achievable technical potential by 2050. The cumulative achievable technical potential includes both economic and non-economic potential.[6] All estimates of potential in this table are presented at the generator, which means they include line losses.[7]

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

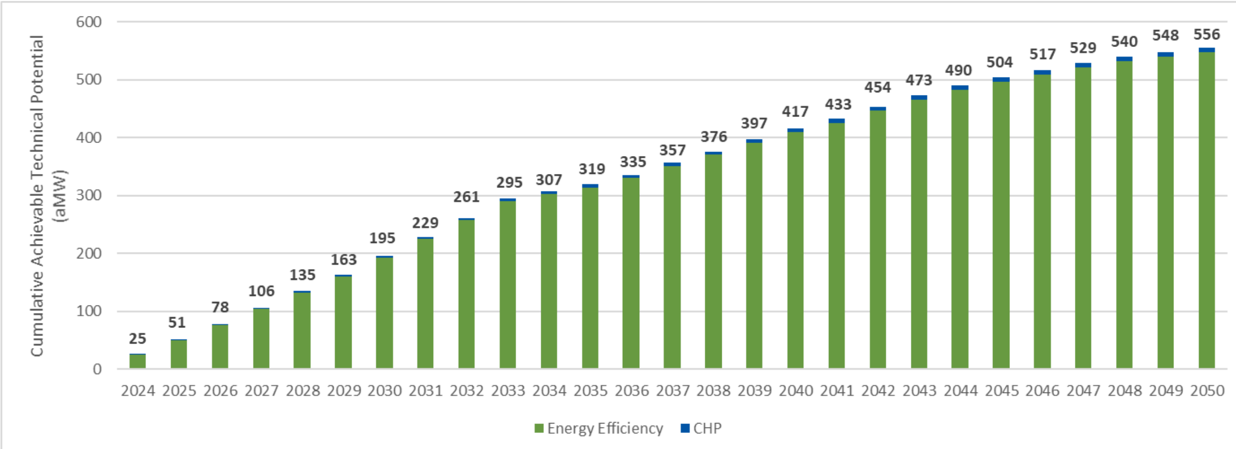
Resource	Energy (aMW)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Energy Efficiency	640	548	831	706
Combined Heat and Power	230	8	287	10
Demand Response	N/A	N/A	N/A	439
Total	**870**	**556**	**1,118**	**1,155**

Figure 1 presents the achievable technical potential forecast for energy efficiency and CHP. 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 primarily from lost opportunity measures, such as equipment replacement and new construction.

6 PSE determines economic potential through the IRP optimization modeling process based on the achievable technical potential inputs from this study.

7 Cadmus assumed line losses of 7.8%.

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



Energy Efficiency

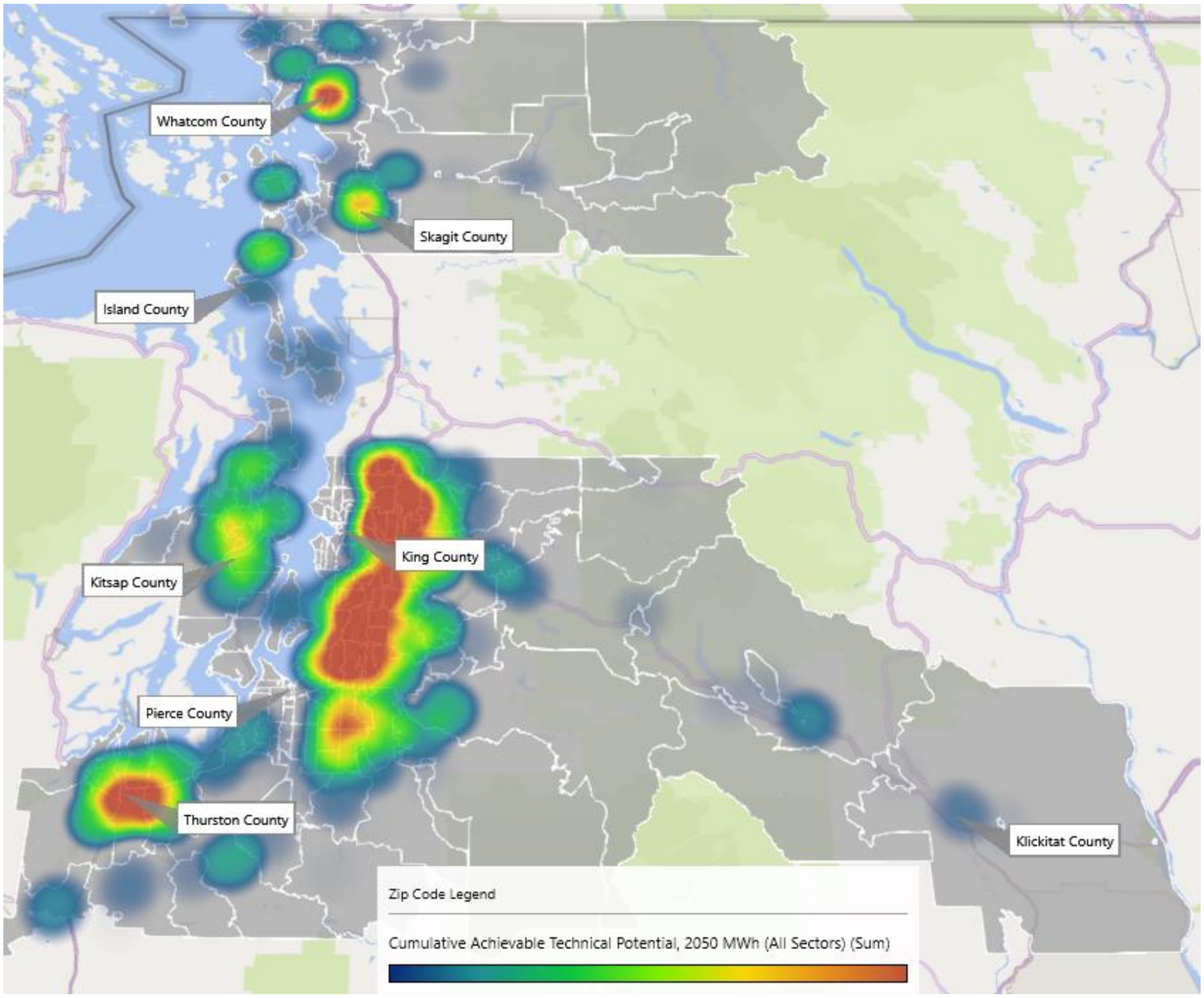
The total achievable technical potential for electric energy efficiency across all sectors is 548 aMW (Table 2). If the 27-year achievable technical potential is realized, it will produce a load reduction equivalent to 18% of PSE's 2050 baseline electric sales. Approximately 55% of this potential is in the residential sector, 42% in the commercial sector, and the remaining 3% in the industrial sector.

Table 2. Energy Efficiency by Sector, Cumulative 2050

Sector	2050 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,818	298	16%
Commercial	1,149	231	20%
Industrial	119	18	16%
Total	**3,086**	**548**	**18%**

The achievable technical potential also can be displayed by zip code, where the potential is proportional to the number of PSE electric customers in each sector. As shown in Figure 2, most of the electric achievable technical potential occurs in King County.

Figure 2. Energy Efficiency Achievable Technical Heat Map by Zip Code — Energy (MWh), Cumulative 2050



Comparison to 2021 CPA – Energy Efficiency

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 the units-based approach used in the 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" of energy and number of customers.
- Incorporated assumptions for savings, cost, and measure lives derived from PSE's 2022 measure business cases, RTF unit energy savings (UES), and draft *2021 Power Plan* supply curve 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)[8], which is PSE-specific for some segments.
- Accounted for the tightening Washington State Energy Code (WSEC) (RCW 19.27A.160),[9] which 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."
- Accounted for the 2018 WSEC residential electric heating provision that new construction homes with electric-zonal heating require ductless mini-split heat pumps.
- Accounted for updates in the Seattle Building Energy Code that require 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.[10]
- Accounted for ordinances passed by the city of Shoreline[11] and by the city of Bellingham[12] for promoting energy efficiency and the decarbonization of commercial and large multifamily buildings and requiring solar readiness for new buildings.

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8 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

9 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

10 The implementation of the space and water heating measures took effect in January 2022. The rest of the code went into effect on March 15, 2021 (see 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). The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required the statewide implementation of similar requirements as the Seattle code update.

11 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. The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required statewide implementation of similar requirements as the Shoreline ordinance.

12 "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. The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required statewide implementation of similar requirements as the city of Bellingham ordinance.

- Accounted for recent changes to federal (residential air conditioning, residential and commercial heat pumps, residential lighting, and commercial direct expansion/packaged terminal air conditioners) and Washington State equipment standards, including products added to state standards by legislation.
- 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 Council typical meteorological year (TMY) to projected future meteorological year (FMY) adjustment factors to weather-sensitive RTF and PSE business case measures, by using residential air conditioning saturations to align with PSE load forecast projections (increasing over time), and by calibrating the CPA heating and cooling 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.[13]
- Estimated the demand-side resource potential for named communities based on PSE's recent vulnerable population data, which 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).

Table 3 shows a comparison of the 24-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2023 and 2021 CPAs. Overall, the 2023 CPA identified 13% lower electric achievable technical potential.

Table 3. Energy Efficiency Comparison of 2023 CPA and 2021 CPA, 24-Year Potential

Study	24-Year Achievable Technical Potential (Percentage of Sales)			Total Achievable Technical Potential (aMW)
	Residential	Commercial	Industrial	
2023 CPA	16%	20%	15%	521
2021 CPA	18%	19% [a]	8%	600

Note: This table compares 24-year results from 2023 CPA to 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 wastewater segment was included in the commercial sector in the 2021 CPA but was included in the industrial sector in the 2023 CPA, following the Council's methodology. There was no separate water supply segment in the 2021 CPA, but there is a water supply segment in the industrial sector in the 2023 CPA, following the Council's methodology

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

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

NEW CONSTRUCTION

- Reductions 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).
- Smaller potential due to only incorporating lighting measures for vulnerable populations (~0.1 aMW).
- Lower heating loads and higher cooling loads due to incorporating climate change impacts. Overall, this impact lowered the potential (as more heating measures than cooling measures were impacted).
- Increase in water heater potential due to the addition of a Tier 4 no resistance, split-system heat pump water heater (HPWH).

COMMERCIAL

- Lower lighting potential (non-lighting control potential) due to using the *2021 Power Plan* commercial lighting characterization and incorporating PSE accomplishments.
- Increased potential with the addition of a dedicated outdoor air system – very high efficiency.
- Increased achievable technical potential in the industrial sector and lower achievable technical potential in the commercial sector due to re-classifying the wastewater segment to the industrial sector and adding the water supply segment to the industrial sector.

INDUSTRIAL

- Increase in potential due to re-classifying the wastewater segment to the industrial sector.
- Increase in potential with the addition of pump and fan measures in the industrial sector.
- Increase in potential with the addition of more lighting controls within the industrial sector.

Combined Heat and Power Potential

Table 4 illustrates the 27-year cumulative achievable technical potential from CHP technologies. Overall, Cadmus identified 7.91 aMW of potential from renewable and nonrenewable technologies.

Table 4. Combined Heat and Power Achievable Technical Potential Summary, Cumulative 2050

CHP Type	Total Achievable Technical Potential (aMW)
Reciprocating Engine	3.90
Natural Gas Turbine	1.31
Microturbine	1.22
Biogas (Anaerobic Digesters)	1.26
Industrial Biomass	0.23
Total	**7.91**

Comparison to 2021 CPA – Combined Heat and Power

Table 5 shows a comparison of the 24-year cumulative CHP achievable technical potential identified in the 2023 CPA to the 24-year cumulative CHP potential in the 2021 CPA. The slight decrease in CHP potential is the result of updates in the data sources.

Table 5. Combined Heat and Power Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA

	2023 CPA (aMW) 24-Year	2021 CPA (aMW) 24-Year
CHP achievable technical potential	7.72	7.82

Demand Response Potential

Table 6 presents the winter and summer peak achievable technical potential for demand response programs. The total 27-year winter demand response potential is 439 MW, which is equivalent to nearly a 7.05% reduction in PSE's forecasted 2050 winter peak.

Table 6. Demand Response Potential by Program, 2050

Product	Winter Achievable Technical Potential (MW)	Percentage of PSE System Peak (Winter)	Summer Achievable Technical Potential (MW)	Percentage of PSE System Peak (Summer)
Residential Electric Resistance Water Heater (ERWH) DLC Switch	0	0.00%	0	0.00%
Residential ERWH DLC Grid-Enabled	32	0.52%	22	0.39%
Residential HPWH DLC Switch	0	0.00%	0	0.00%
Residential HPWH DLC Grid-Enabled	58	0.94%	29	0.53%
Residential HVAC DLC Switch	97	1.56%	50	0.90%
Residential Bring Your Own Thermostat (BYOT) DLC	108	1.74%	100	1.81%
Residential EVSE DLC Switch	42	0.67%	42	0.75%
Medium Commercial HVAC DLC Switch	18	0.30%	77	1.40%
Small Commercial HVAC DLC Switch	3	0.04%	5	0.10%
Small Commercial BYOT DLC	3	0.05%	4	0.07%
Commercial Curtailment	16	0.26%	20	0.36%
Industrial Curtailment	5	0.08%	5	0.09%
Residential Critical Peak Pricing	33	0.54%	74	1.35%
Commercial Critical Peak Pricing	21	0.34%	26	0.48%
Industrial Critical Peak Pricing	2	0.02%	2	0.03%
Total	**439**	**7.05%**	**455**	**8.24%**

Comparison to 2021 CPA – Winter Demand Response

Table 7 shows a comparison of the demand response potential identified in the 2023 and 2021 CPAs, by sector. The 2023 CPA identified more winter potential compared to the 2021 CPA.

Table 7. Demand Response Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA, Winter

Sector	2023 CPA (MW) 24-Year	2021 CPA (MW) 24-Year
Residential	365	206
Commercial and Industrial	67	20
Total	**431**	**226**

Several of the Council's draft *2021 Power Plan* alignments and key modeling inputs updates contributed to the increase in demand response potential and differences in product levelized costs:

Draft 2021 Power Plan Alignments

- Accounted for demand response updates made following Demand Response Advisory Committee (DRAC) discussions (such as shorter product ramp rates).
- Aligned closer with draft *2021 Power Plan* product input assumptions, such as per-participant kilowatt impacts and program participation estimates. For example, participation assumptions increased for HPWH and grid-enabled ERWH DLC (from 24% to 50%), for residential HVAC switch (from 20% to 25%), for residential BYOT (from 20% to 35%), and for curtailment (from 3% to 15%).

Key Modeling Inputs Updates

- Updated equipment saturations based on new data, such as PSE's 2021 RCS, PSE's electric vehicle forecast, and estimates of energy efficiency measure adoption. Modeled electric HVAC, smart thermostats, electric water heating (ERWH versus HPWH), and electric vehicle (EV) saturations dynamically over the study's duration, incorporating anticipated growth in future years.
- Updated nonresidential segmentation data using PSE's 2021 nonresidential customer database to segment building types based on Standard Industrial Classification and North American Industrial Classification System identifiers. (The prior study used historical segment allocations based on 2014 data.)
- Updated product input assumptions based on Cadmus' literature research (where applicable).
- Split costs between seasons (which was not conducted for the prior study). This impacted the demand response per-product levelized cost estimates.
- Updated transmission and distribution (T&D) deferral costs from $16 per kilowatt-year to $75 per kilowatt-year. This impacted the levelized cost estimates.
- Did not model the residential behavioral product (which was included in the 2021 CPA) but did model small commercial BYOT (which was not included in the 2021 CPA).

Rooftop Solar PV Potential

For 2050 Cadmus identified solar PV nameplate capacity achievable technical potential of 645 MW in the residential sector (including vulnerable populations) and 778 MW in the commercial sector, which is equivalent to 74.1 aMW and 95.8 aMW of cumulative achievable energy potential for the residential and commercial sectors, respectively.

Comparison to 2021 CPA – Rooftop Solar PV

Table 8 shows a comparison of solar PV achievable technical potential identified in the 2023 and 2021 CPAs by sector. The 2023 CPA estimate through 2050 shows 1,087 MW (nameplate) more achievable technical potential than the 2021 CPA estimate through 2045. If compared over a similar 24-year period, the difference in potential is 730 MW. The increase in solar PV potential is primarily the result of updated historical adoption (within the past two years) and projected near-term adoption (2022 and 2023) that shows increased solar installations. This impacted the customer adoption diffusion model (dGen) to better align with historical adoption.

Table 8. Solar PV Achievable Technical Potential (Nameplate) Comparison of 2023 CPA and 2021 CPA

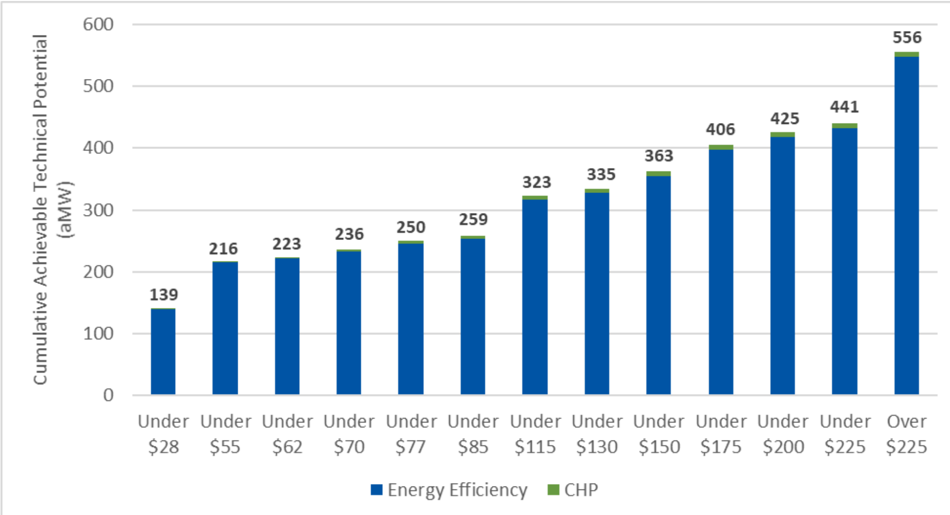
Sector	2023 CPA (MW) 27-Year	2021 CPA (MW) 24-Year
Residential	645	87
Commercial	778	249
Total	**1,423**	**336**

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

Cadmus grouped the achievable technical potential for energy efficiency and CHP 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, rather we used the CPA IRP inputs within PSE's optimization modeling that select the least-cost (cost-effective) resource.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce hourly 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 hourly savings across months. Figure 3 shows the annual cumulative combined potential for energy efficiency and CHP by each cost bundle considered in PSE's 2023 IRP.

Figure 3. Electric Supply Curve, Cumulative 27-Year Achievable Technical Potential



Similarly, Cadmus spread the annual savings estimates for rooftop solar PV over 8760-hour load shapes to produce hourly demand-side resource bundles. The demand response programs are a capacity-only resource. The annual capacity potential for each year of this study was incorporated into the IRP along with the net costs, which accounted for the estimated program costs and T&D deferral benefits.

Organization of This Report

This report presents the findings of demand-side electric resource potential assessment in several chapters and one appendix:

- *Chapter 1. Energy Efficiency and Combined Heat and Power 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 with discussion of the top-saving measures in each sector. It also presents the estimates of technical and achievable technical CHP potential and levelized costs.
- *Chapter 2. Demand Response Potential* presents the winter and summer peak achievable technical potential for demand response programs.
- *Chapter 3. Rooftop Solar PV Potential* presents the solar PV nameplate capacity achievable technical 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* gives detailed information on demand response potential by program and product option.

Chapter 1. Energy Efficiency and Combined Heat and Power Potential

PSE requires accurate estimates of technically achievable 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 electric resources in the residential, commercial, and industrial sectors. The next 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 the considerations for the design of this potential study. Lastly, the results of energy efficiency and CHP potential assessment are presented in detail.

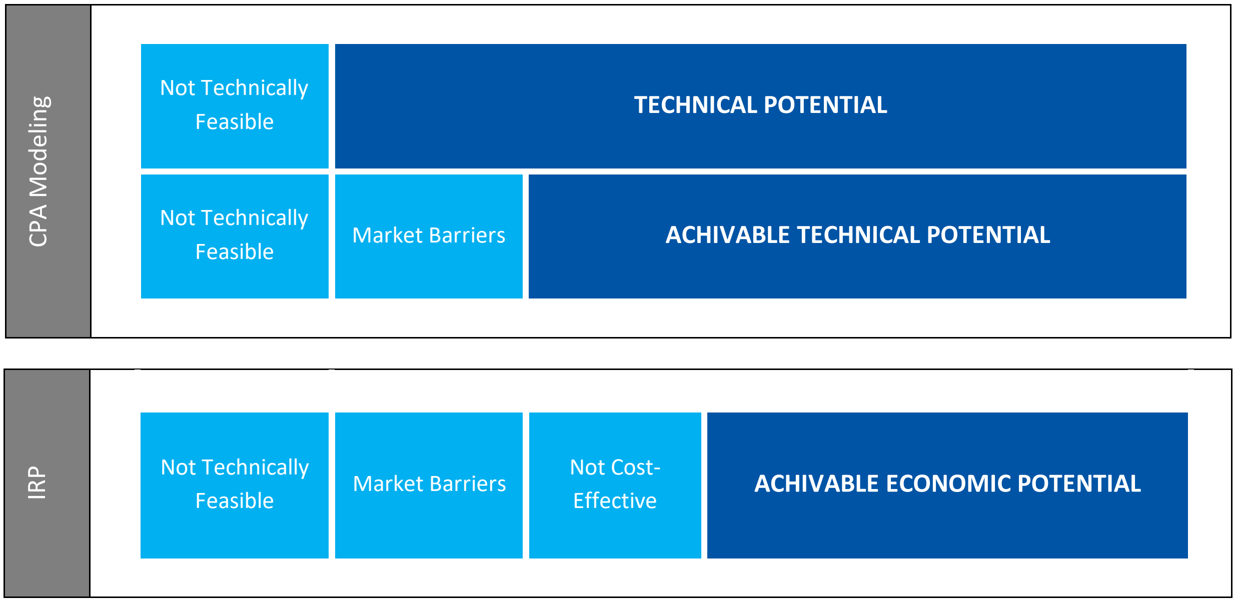
Energy Efficiency Potential

Consistent with the WAC requirements, Cadmus assessed two types of energy efficiency potential—technical and achievable technical. PSE determined a third potential—achievable economic—through the IRP's optimization modeling. These three types of potential are illustrated in Figure 4.

- ***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 portion 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 4. 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, economizer optimization, 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, appliances, and replace-on-burnout lighting fixtures.

Cadmus analyzed three sectors—residential, commercial, industrial—and, where applicable, considered multiple market segments, construction vintages (new and existing), and end uses:

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
SIX SEGMENTS Single family, multifamily, manufactured, single family - vulnerable population, multifamily - vulnerable population, and manufactured - vulnerable population segments	**EIGHTEEN SEGMENTS** Office, retail, and food sales segments further divided into categories based on building size, aligning with the *2021 Power Plan*	**TWENTY-ONE SEGMENTS** Paper, chemical, wood, hi-tech, and other 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). 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 three 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, corporate sector, and market load forecast produced in 2022. Baseline forecast in this report include 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 the approach we used for this 2023 CPA:

- 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 changed relevant inputs at the end-use level to reflect energy conservation measure (ECM) impacts. Because estimated savings represented 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 5, 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.

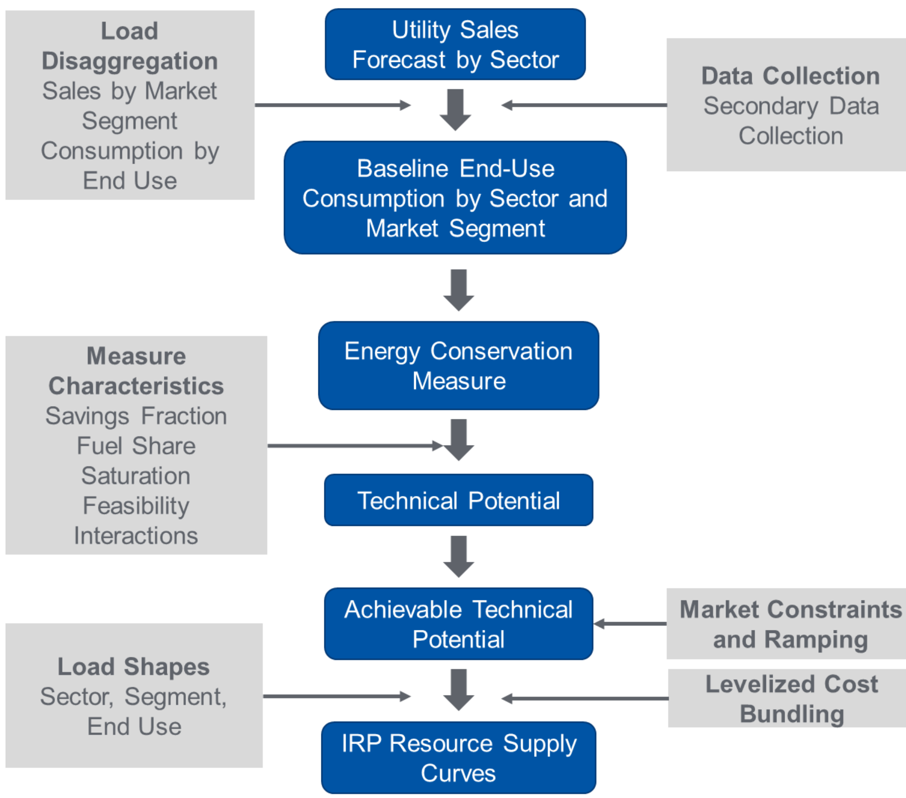
For the bottom-up component, Cadmus estimated electric consumptions for each major building end use and applied potential technical impacts of various ECMs to each end use. This bottom-up analysis includes assumptions about end-use equipment saturations, fuel shares, ECM technical feasibility, ECM cost, and engineering estimates of ECM unit energy consumption 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.[14] Next, we calibrated annual changes in residential and commercial heating and cooling end-use consumptions with PSE's climate impacts within annual load forecasts to reflect climate change on CPA estimates. Cadmus also used the projected residential air conditioning saturations within PSE load forecast projections.

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

Figure 5. Conservation Potential Assessment Methodology



14 Cadmus applied climate change adjustment factors based Council 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 hourly forecasts of electric energy efficiency potential. To produce these hourly forecasts, Cadmus applied hourly end-use load 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 this study's 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 over time, 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 Council and RTF incremental energy efficiency measure costs, including for equipment, labor, and operation and maintenance (O&M), but it does not attempt to forecast changes to these costs during the course of the study (except where the Council will make adjustments). 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 19.285.040[15] requires PSE to complete and update a CPA every two years. PSE

[15] Revised Code of Washington. Accessed August 24, 2022. "RCW 19.285.040 Energy Conservation and Renewable Energy Targets." https://app.leg.wa.gov/RCW/default.aspx?cite=19.285.040&pdf=true

can address some of these considerations over time and mitigate short- and mid-term uncertainties by continually revising CPA assumptions to reflect changes in the market.

Energy Efficiency Potential - Overview

Table 9 shows 2050 forecasted baseline electric sales and potential by sector.[16] Cadmus' analysis indicates that 640 aMW of technically feasible electric energy efficiency potential will be available by 2050, the end of the 27-year planning horizon, which translates to an achievable technical potential of 548 aMW. Should all this achievable technical potential prove cost-effective and realizable, it will result in an 18% reduction in 2050 forecasted retail sales.

Table 9. Electric 27-Year Cumulative Energy Efficiency Potential

Sector	2050 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,818	298	16%
Commercial	1,149	231	20%
Industrial	119	18	16%
Total	**3,086**	**548**	**18%**

Figure 6 shows each sector's relative share of the overall electric energy efficiency achievable technical potential. The residential sector accounts for roughly 55% of the total electric energy efficiency achievable technical potential, followed by the commercial (42%) and industrial (3%) sectors.

Figure 6. 27-Year Achievable Technical Potential by Sector

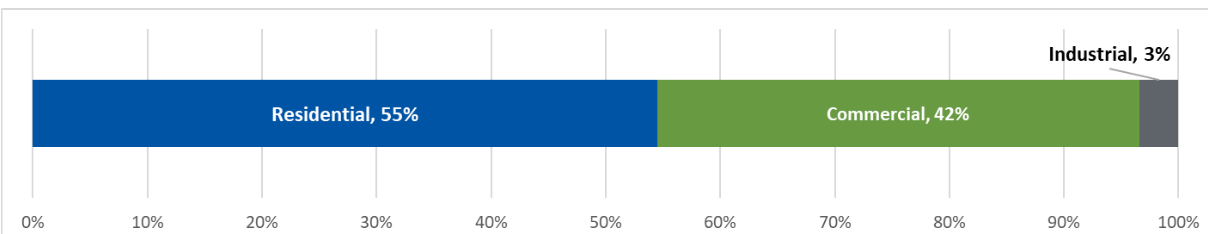


Figure 7 shows the relationship between each sector's cumulative (through 2050) electric energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[17] For example, approximately 355 aMW of achievable technical potential exists at a cost less of than $150 per megawatt-hour.

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16 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.

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

Figure 7. Electric 27-Year Cumulative Energy Efficiency Supply Curve

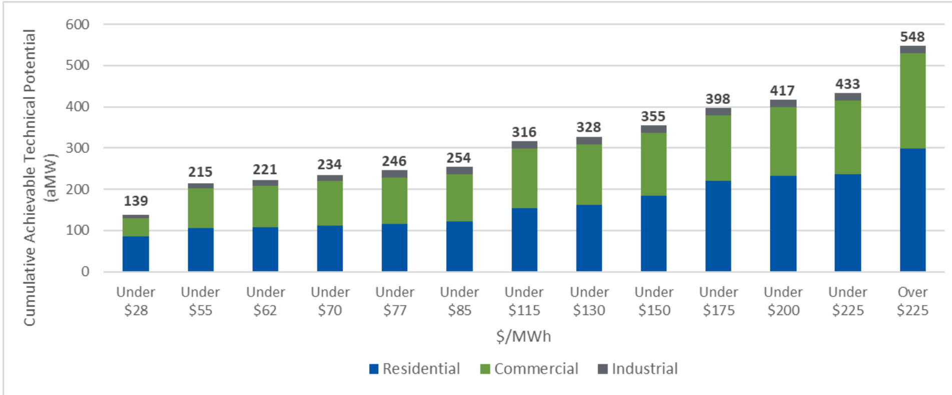
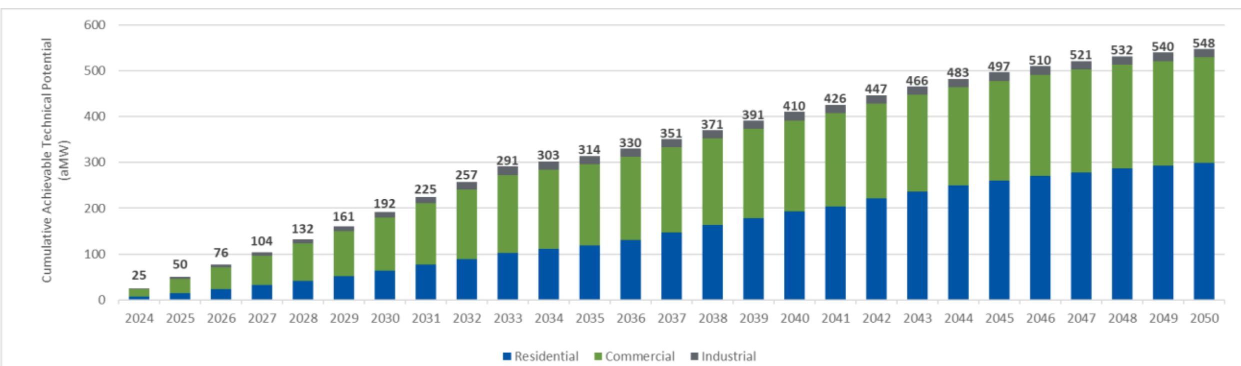


Figure 8 illustrates the cumulative potential that is available annually in each sector. As shown in the figure, more savings are achieved in the first 10 years of the study (2024 through 2033) than in the remaining years. For this study, Cadmus assumed that discretionary measure potential savings are 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. Electric Energy Efficiency Potential Forecast

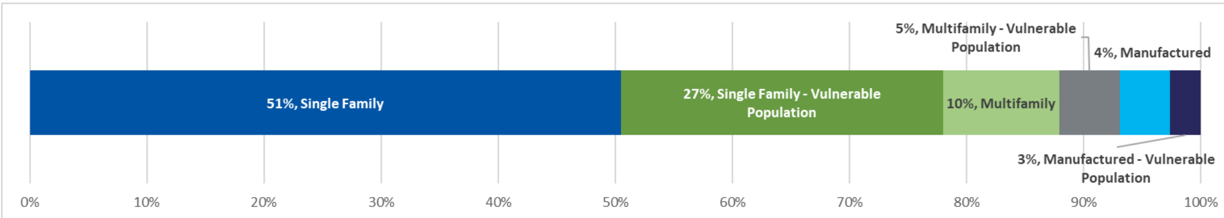


Energy Efficiency Potential - Residential Sector

By 2050, residential customers in PSE's service territory will likely account for approximately 59% of forecasted electric retail sales. The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (such as heat pumps and refrigerators), improvements to building shells (via insulation, windows, and air sealing), and increases in domestic hot water efficiency (such as HPWHs).

As shown in Figure 9, single-family homes represent 78% of the total achievable technical residential electric potential followed by multifamily (15%) and manufactured homes (7%), with all categories 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 to determining potential.

Figure 9. Residential Electric Achievable Technical Potential by Segment



For example, a higher percentage of manufactured homes use electric heat compared to single-family and multifamily homes, which increases their relative share of the potential. However, 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.

Space heating end uses represent the largest portion (36%) of achievable technical potential, followed by water heating (24%) and dryer (15%) end uses (Figure 10). Lighting, an end use with considerably low energy efficiency potential in the 2021 CPA, comprises only 2% of the total residential electric energy efficiency potential. This low potential is due to the updated Washington State standard (House Bill 1444) and greater penetration of screw-based LEDs in recent years. The total achievable technical potential for residential increases to 298 aMW over the study horizon (Figure 11).

Figure 10. Residential Electric Achievable Technical Potential by End Use

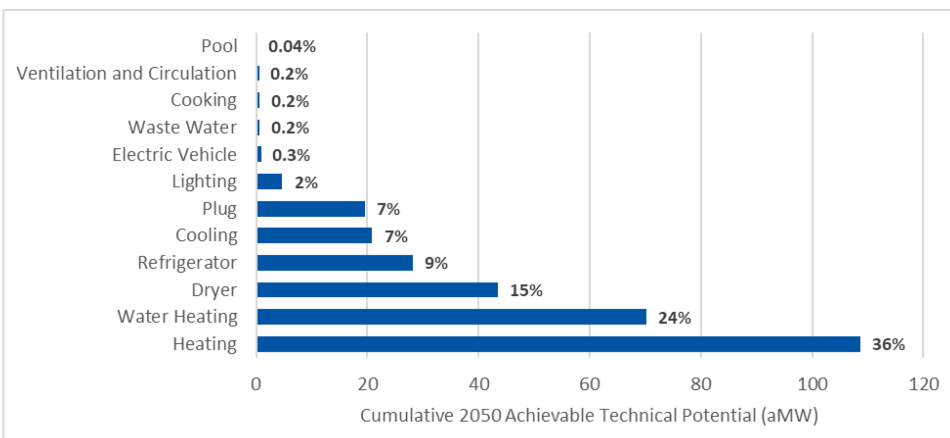


Figure 11. Residential Electric Achievable Technical Potential Forecast by End Use

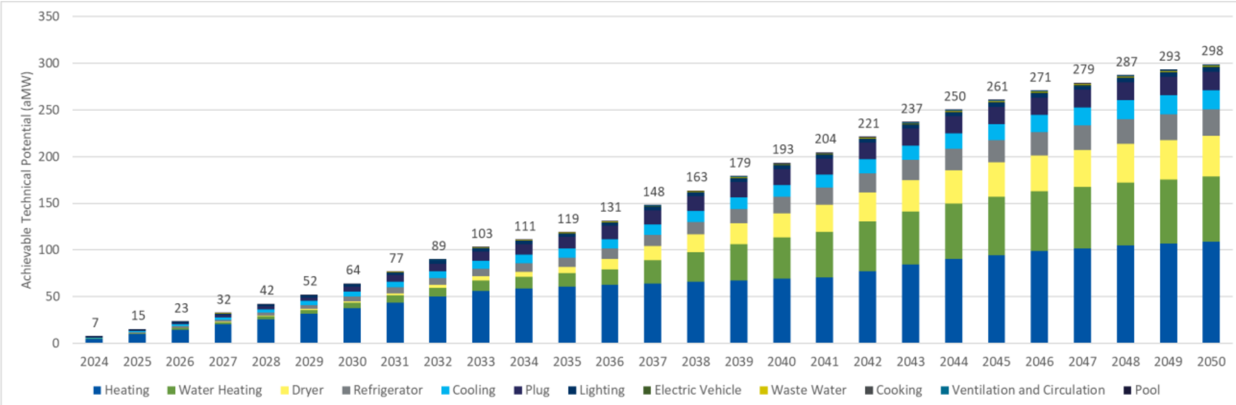


Table 10 lists the top 10 residential electric energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for roughly 209 aMW, or approximately 70% of the total residential electric achievable technical potential. Heat pump dryers represent the measure with the highest energy savings and four of the top 10 measures reduce electric heating loads: this includes equipment measures (ductless heat pumps and air-source heat pumps) and a retrofit measure (smart thermostats). This list represents both economic and non-economic measures.

Table 10. Top Residential Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Heat Pump Dryer	4.0	43.0
Heat Pump Water Heater - Tier 4 - No Resistance, Split System	3.7	37.8
Zonal to Ductless Heat Pump	5.2	23.7
Heat Pump Water Heater - Tier 3	2.2	22.7
HVAC Upgrade - Heat Pump Upgrade to 12 HSPF/18 SEER	2.2	22.0
Refrigerator - ENERGY STAR 2022 Most Efficient	5.8	21.9
Install Ductless Heat Pump in House with Existing Forced Air Furnace - HZ1	2.9	13.5
Central Air Conditioner - Enhanced	1.8	10.9
Set Top Box - ENERGY STAR	3.4	7.4
Smart Thermostat	5.9	6.5

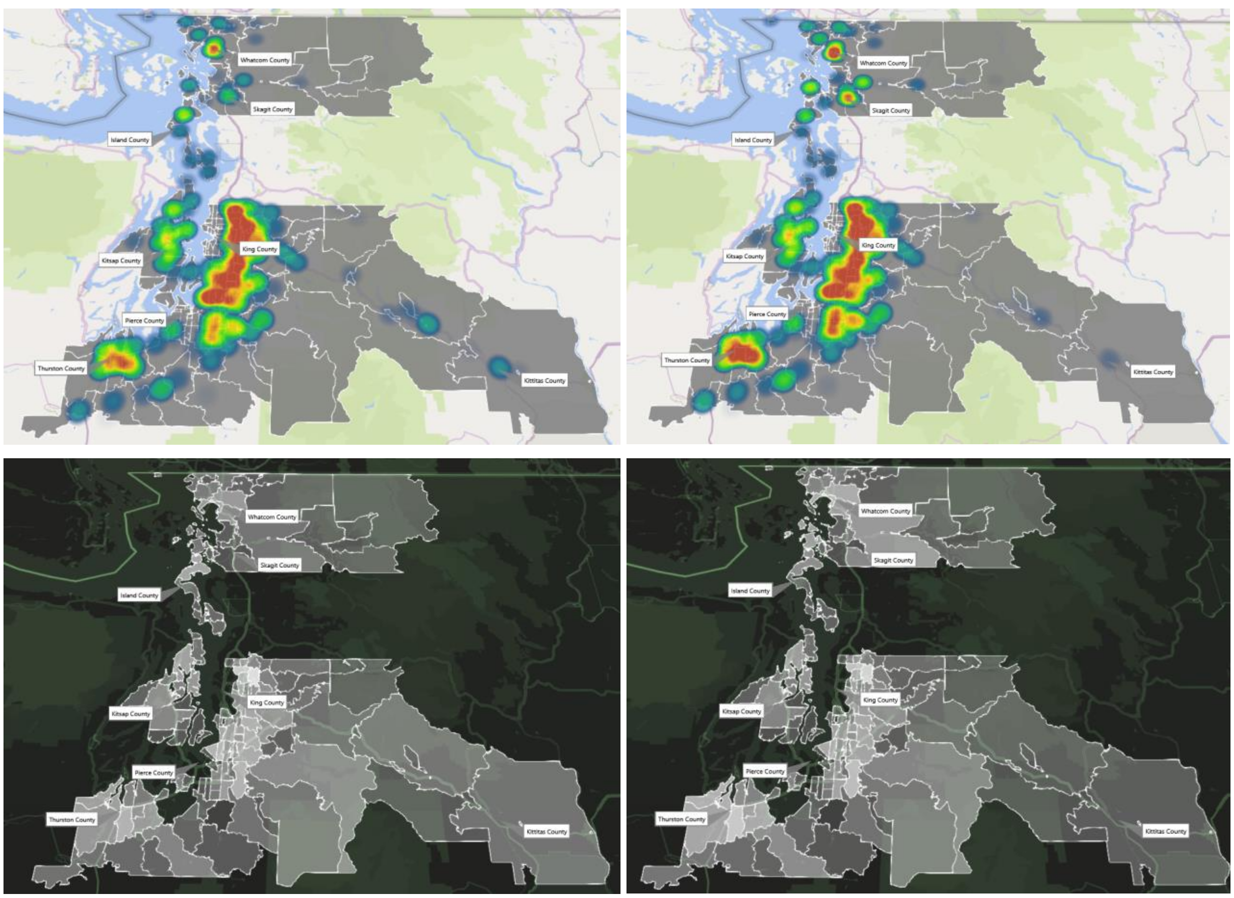
In addition to estimating potential for each residential housing segment, Cadmus estimated potential for vulnerable population customers within PSE's electric service territory. Cadmus segmented PSE residential accounts (single family, multifamily, and manufactured) for vulnerable populations by county. Cadmus also used PSE 2021 RCS data to inform equipment saturations and fuel shares for vulnerable populations (based on income). Table 11 provides the percentage of vulnerable population customers in each county in PSE's electric service territory.

Table 11. Percentage of Vulnerable Population Customers in Each County

County	Percentage of Vulnerable Population Customers
Island County	28%
King County	34%
Kitsap County	35%
Kittitas County	12%
Pierce County	38%
Skagit County	58%
Thurston County	41%
Whatcom County	42%

Figure 12 shows a heat map comparison of the achievable technical cumulative potential (2050) for the residential market rate (left images) and residential vulnerable population (right images) customer segments. Overall, there is little difference in the locational achievable potential (by zip code). However, the vulnerable population shows proportionally higher potential in Thurston, Whatcom, and Skagit counties when compared market rate customer population.

Figure 12. Residential Market Rate (Left) and Residential Vulnerable Population (Right) Heat Map



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/duct sealing, single and double 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 advanced power strips, home energy reports, windows (double and triple pane with different U factors), and string lighting.

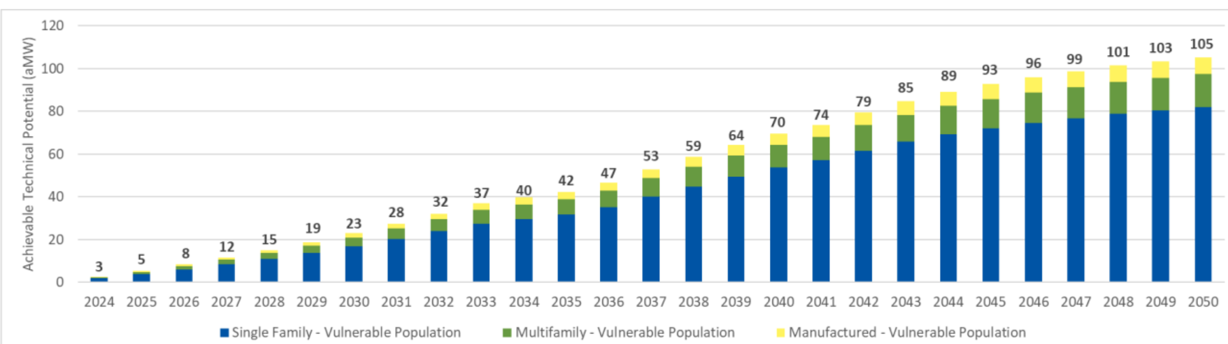
Table 12 shows the cumulative 10-year (through 2033) and 27-year (through 2050) achievable technical potential for PSE's vulnerable population customers by housing segment.

Table 12. Residential Vulnerable Population Customer Potential - Electric

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-Year Achievable Technical Potential (aMW)
Single Family - Vulnerable Population	27.5	82.0
Multifamily - Vulnerable Population	6.5	15.4
Manufactured - Vulnerable Population	3.0	7.9
Total	**36.9**	**105.2**

Figure 13 provides the cumulative residential vulnerable population electric achievable technical potential forecast by housing segment. The potentials that were shown above in Figure 11 include the vulnerable population customer potential shown in Figure 13.

Figure 13. Residential Achievable Technical Potential Forecast for Vulnerable Populations

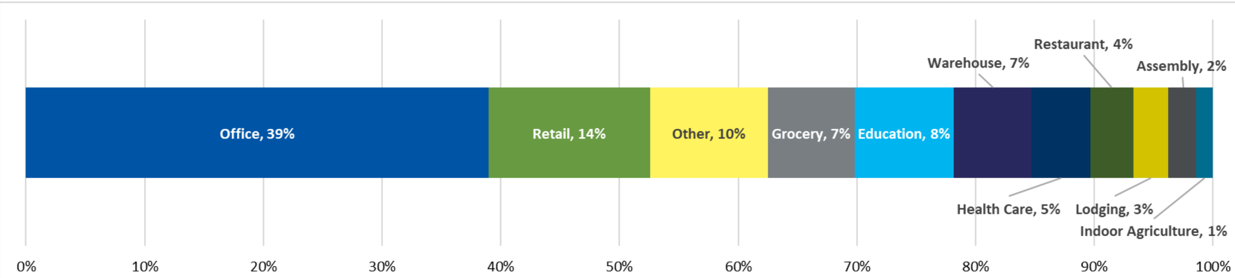


Energy Efficiency Potential - Commercial Sector

Based on the energy efficiency measure resources used in this assessment, electric energy efficiency achievable technical potential in the commercial sector will likely be 231 aMW over 27 years, which is approximately a 20% reduction in forecasted 2050 commercial sales.

As shown in Figure 14, the office and retail segments represent 39% and 14%, respectively, of the total commercial achievable technical potential. The "other" segment, which includes customers who do not fit into any of the categories and customers with insufficient information for classification, represents 10% of commercial achievable technical potential. Each of the remaining segments has less than 10% of commercial achievable technical potential.

Figure 14. Commercial Electric Achievable Technical Potential by Segment



As shown in Figure 15, lighting efficiency improvements represent the largest portion of achievable technical end-use savings potential in the commercial sector (39%), followed by ventilation and circulation (25%) and cooling (13%). Figure 16 presents the annual cumulative electric commercial achievable technical potential by end use.

Figure 15. Commercial Electric Achievable Technical Potential by End Use

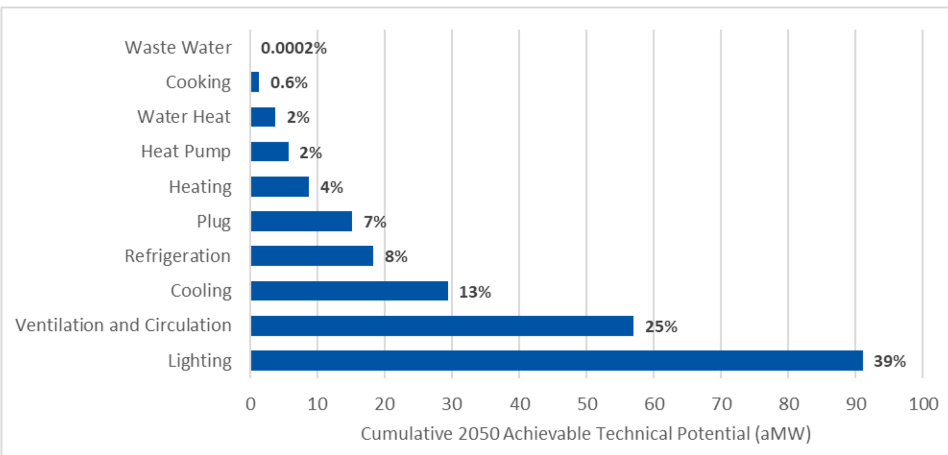


Figure 16. Commercial Electric Achievable Technical Potential Forecast

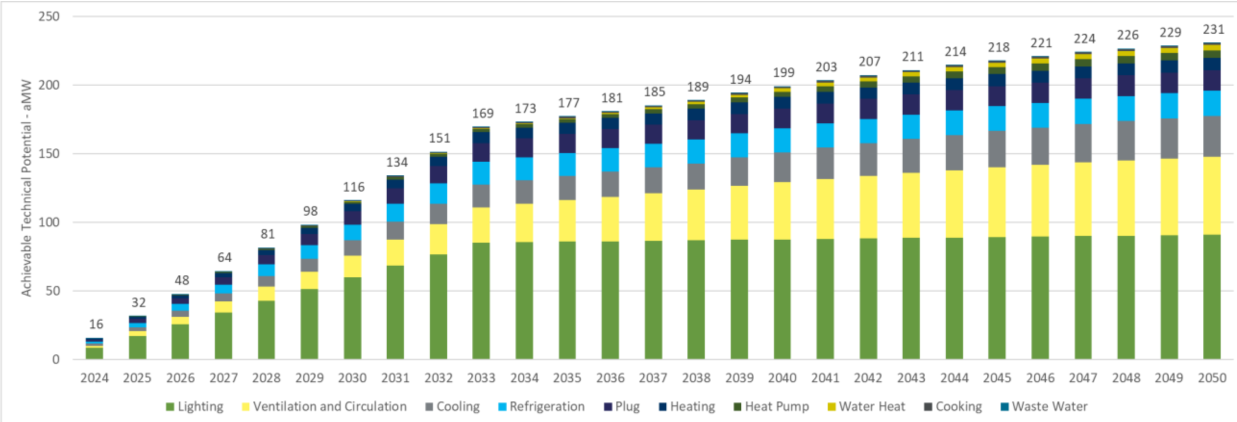


Table 13 lists the top 10 commercial electric energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for 150 aMW, or approximately 65% of the total electric commercial achievable technical potential.

Table 13. Top Commercial Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Lighting - Interior - Control	46.59	51.35
Lighting - Interior - LED	20.43	20.48
Fan - Variable Speed Drive	3.03	15.12
Window - Upgrade	12.42	13.66
Cooling Direct Expansion	2.39	11.18
Exit Sign	8.11	8.43
Very High-Efficiency Dedicated Outside Air System	1.10	8.41
Lighting - Exterior - LED	6.47	7.02
Rooftop HVAC Controls - Advanced	6.88	6.98
Pump - Efficient	3.57	6.93

Energy Efficiency Potential - Industrial Sector

Cadmus estimated technical and achievable technical energy efficiency potential for major end uses in 21 major industrial sectors and for street lighting. It is worth noting that water supply and wastewater treatment are new segments in the industrial sector for this CPA, aligning with the draft *2021 Power Plan*. In prior CPAs (and previous power plans), these segments were considered part of the commercial sector. This change was made by the Council to better align with utility program functions, as utilities offer energy efficiency to the water and wastewater segments through their industrial programs. Across all industries, achievable technical potential is approximately 18 aMW over the 27-year planning horizon, corresponding to a 16% reduction of forecasted 2050 industrial electric retail sales.

Figure 17 shows 27-year electric industrial achievable technical potential by segment. Sewage treatment represents 21% of the total 27-year electric industrial achievable technical potential, followed by miscellaneous manufacturing (19%), streetlighting (14%), water supply (12%), and transportation equipment (10%). No other industry represents more than 5% of industrial electric achievable technical potential.

Figure 17. Industrial Electric Achievable Technical Potential Forecast

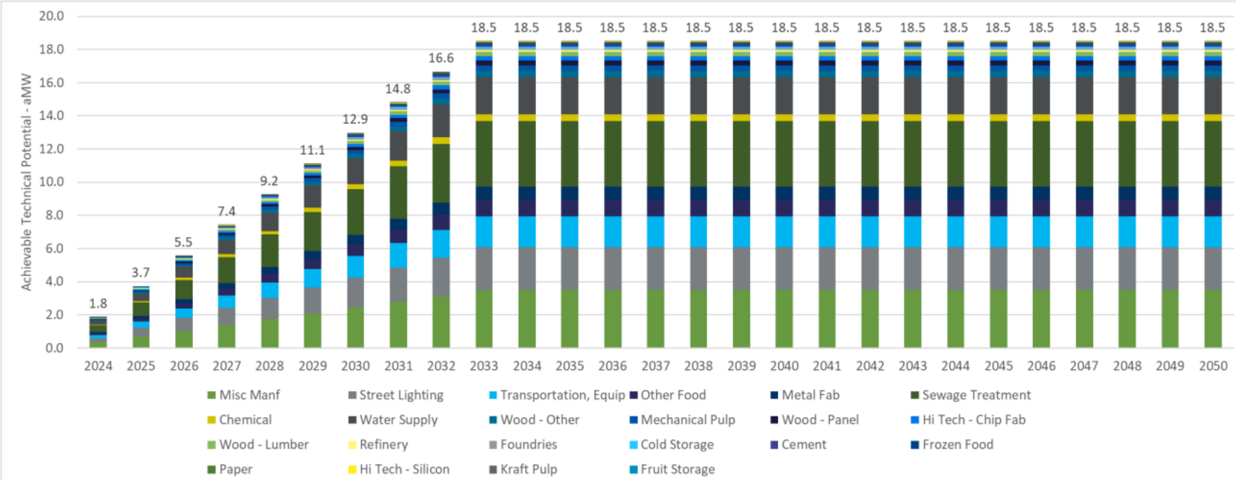


Table 14 presents electric cumulative 27-year achievable technical potential for the top 10 measures in the industrial sector. Cadmus derived these measures from the Council's draft *2021 Power Plan.* The top three measures combined—wastewater, water supply, and energy management—equal approximately 7.8 aMW of achievable technical potential, or roughly 43% of the industrial total.

Table 14. Top Industrial Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Wastewater	3.9	3.9
Water Supply	2.2	2.2
Energy Management	1.6	1.6
HVAC	0.9	0.9
Streetlight - HPS 100 Watt - Group Relamp - to LED 38 Watt - Retrofit	0.8	0.8
Lighting Controls	0.8	0.8
Energy Management Level 2	0.8	0.8
Streetlight - HPS 100 Watt - Group Relamp - to LED 53 Watt - Retrofit	0.7	0.7
Pump Optimization	0.6	0.6
Advanced Motors - Material Processing	0.5	0.5

The energy management category represents facility-wide adoption of energy efficiency, primarily through the Industrial Strategic Energy Management program and other similar programs offered by PSE.[18] In the draft *2021 Power Plan*, there are two levels of strategic energy management. The first level

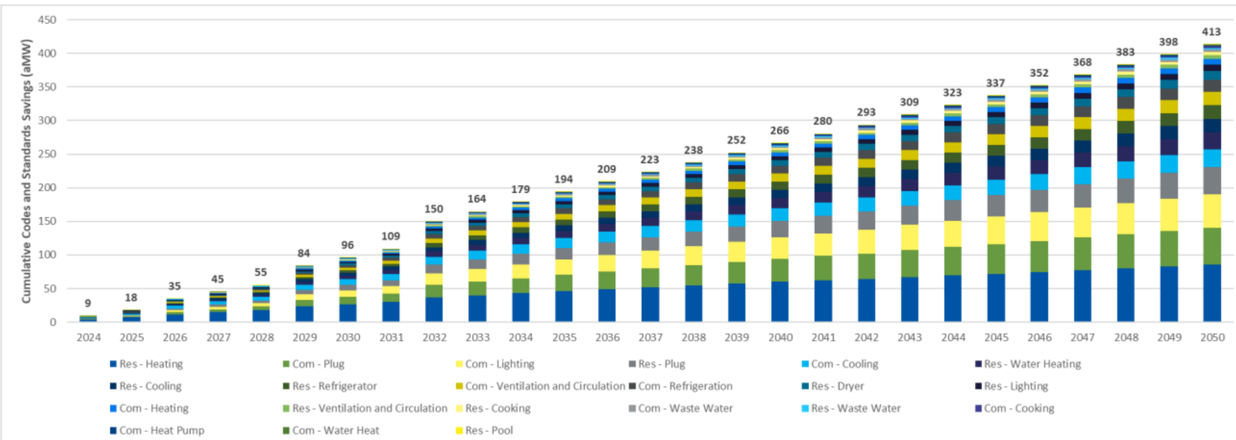
18 Puget Sound Energy. Accessed August 2022. "Industrial Strategic Energy Management (ISEM) program." https://www.pse.com/business-incentives/commercial-industrial-programs/industrial-strategic-energy-management

(known as energy management) is defined as the traditional achievable amounts of energy efficiency and at a cost realized through recent program activities. The second level of strategic energy management (known as energy management level 2) represents either future potential that is more difficult to achieve at smaller facilities or deeper achievements at facilities that have already achieved level 1. The cost of energy management level 2 is higher than the cost of energy management level 1.

Impacts of Codes and Standards

Figure 18 presents naturally occurring savings in PSE’s service area from the WSEC equipment standards and federal equipment standards, which is equal to 413 aMW in 2050.

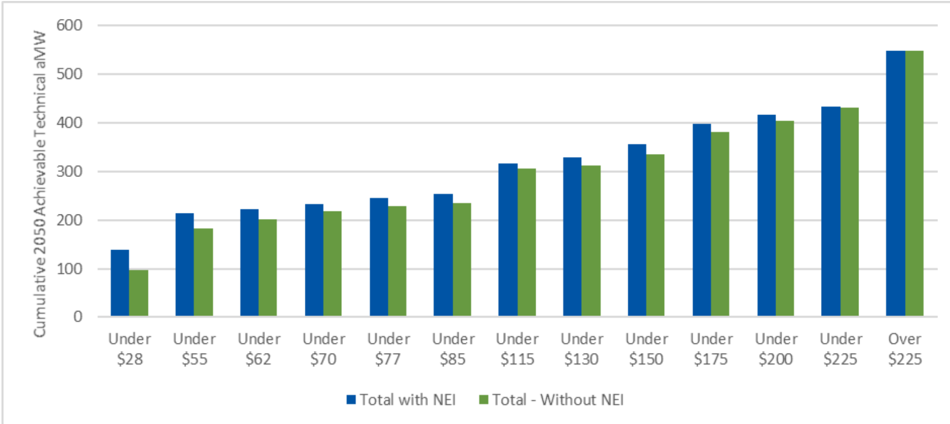
Figure 18. Electric Codes and Standards Potential Forecast



Non-Energy Impacts

In addition to the Council and RTF measures with NEIs (limited to water savings, O&M, and lifetime replacement), this CPA incorporated 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 19 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 lower-cost bundles with less of an impact in the high-cost bundles.

Figure 19. Non-Energy Impacts on Levelized Cost, Cumulative 2050 Achievable Technical Potential



Combined Heat and Power Potential

CHP produces electricity and thermal energy at high efficiencies using different technologies and fuels. With CHP providing on-site power, losses are minimized and heat that would otherwise be wasted can be used in the form of process heating, steam, hot water, or even chilled water.[19]

In this study, CHP technical potential represents total electric generation if installing all resources in all technically feasible applications. Technical potential assumes that every end-use customer in PSE's service territory—if meeting CHP energy demand requirements—installs a system. This largely unrealizable potential should be considered a theoretical construct.

Cadmus assessed applicable, technical CHP potential for the C&I sectors in PSE's service area. Traditionally, CHP systems have been installed in hospitals, schools, universities, military bases, and manufacturing facilities. They can be used, however, across nearly all C&I market segments that have average monthly energy loads greater than approximately 30 kW.

CHP can be broadly divided into two subcategories, based on the fuels used:

- Nonrenewable CHP, typically using natural gas
- Renewable systems using biologically derived fuel (biomass or biogas)

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[19] U.S. Environmental Protection Agency. Last updated June 1, 2022. "What Is CHP?" https://www.epa.gov/chp/what-chp

NON-RENEWABLE FUEL	RENEWABLE FUEL: BIOMASS	RENEWABLE FUEL: BIOGAS
• Reciprocating engines that cover a wide range of sizes • Microturbines that represent newer technologies with higher capital costs • Gas turbines that are typically large systems	Used in industries where site-generated waste products (such as lumber wood, panel wood, and other wood products) can be combusted in place of natural gas or other fuels. For this study, Cadmus assumed that the type of combustion processes in a CHP system (generally steam turbines) would generate electricity on the site. An industrial biomass system generally operates on a large scale, with a capacity greater than 1 MW.	Used with anaerobic digesters, which generate biogas—primarily consisting of methane, carbon dioxide, and hydrogen sulfide—from the decomposition of liquid or solid organic waste by microorganisms in an oxygen-free environment. Anaerobic digesters can be coupled with a variety of generators, including reciprocating engines and microturbines, and are typically installed at landfills, wastewater treatment facilities, livestock farms, and pulp and paper manufacturing facilities.

Cadmus calculated technical potential to determine the demand, or the number of eligible customers by segment and size in PSE's service area, then applied assumptions about CHP or biomass/biogas system sizes and performance. Table 15 lists the sources Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program have the largest sample sizes (as it is the longest-running CHP program in the nation). Cadmus also reviewed studies from other regions and, where possible, benchmarked California Self-Generation Incentive Program data with other studies.

Table 15. Data Sources for Combined Heat and Power Technical Potential

Inputs	Source
Capacity Factor, Performance Degradation, Heat Recovery Rate	Itron. October 2015. *2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. p. 4-13. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/7889-20151119finalfullreport-1-.pdf
Measure Life	Marin, William, Myles O'Kelly, and Kurt Scheuermann. August 11–13, 2015. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. International Energy Program Evaluation Conference, Long Beach, California. https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	Self-Generation Incentive Program. Accessed January 2022. *Self-Generation Incentive Program Weekly Statewide Report.* https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers, Projected Sector Growth, Line Losses	PSE data
Existing CHP Capacity	U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power and Microgrid Installation Database." https://doe.icfwebservices.com/chpdb/
Customer Size Data	PSE data

Cadmus applied an achievable penetration rate to technical potential estimates to determine the market potential or likely future installations. Determining this rate involved reviewing a range of market penetration estimates, listed in Table 16. We examined historical trends in installed capacity for several states (including Washington), several technologies, and various fuel types using the

U.S. Department of Energy CHP Installation Database and reviewing states' favorability toward CHP as scored by the American Council for an Energy-Efficient Economy.

Table 16. Data Sources for Combined Heat and Power Achievable Technical Potential

Input	Source
Annual Market Penetration Rate	U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power Installation Database." https://doe.icfwebservices.com/chpdb/
	Navigant Consulting. June 30, 2017. *2017 IRP Demand-Side Management Conservation Potential Assessment Report.* Prepared for Puget Sound Energy. https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/IRP17_AppJ.pdf
	U.S. Department of Energy. March 2016. *Combined Heat and Power (CHP) Potential in the United States.* https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
	ICF International. June 2012. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. CEC-200-2012-002-REV. https://efiling.energy.ca.gov/GetDocument.aspx?tn=65855
	American Council for an Energy-Efficient Economy. n.d. "State-by-State CHP Favorability Index Estimate." http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

Using the American Council for an Energy-Efficient Economy "State-by-State CHP Favorability Index Estimate," we identified the top three most favorable states for CHP (California, Connecticut, and Massachusetts) and calculated the percentage of technical potential installed per year in these states over the five-year period from 2012 through 2016. We also calculated this percentage for Washington State for comparison. To determine this percentage, Cadmus divided the capacity of CHP installed over the five-year period of 2012 through 2016 (from the U.S. Department of Energy CHP Installation Database) by the CHP potential (from the 2016 U.S. Department of Energy CHP Potential in the United States) then divided by five years. This provided an upper bound for the annual market penetration rate in PSE territory. Based on the benchmarking results (shown in Table 17), as well as the other data sources, we assumed an annual market penetration rate of 0.2% to provide the most likely and realistic achievable technical potential (0.2% is also the annual market penetration rate used for the 2021 CPA).

Table 17. Market Penetration for 2012–2016

State	Installed from 2012–2016 (MW)	Technical Potential (MW)	Percentage of Technical Potential Installed Per Year
Washington	**22.0**	**2,387**	**0.184%**
California	382.2	11,542	0.662%
Connecticut	15.1	1,214	0.248%
Massachusetts	40.2	3,028	0.265%

For each technology, Cadmus calculated several types of levelized cost from a total resource cost (TRC) perspective. Although assumptions varied between technologies, these sources were included in overall total resource levelized costs:

- Installation costs
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs (including total carbon adder)

- Incentives[20]
- Program administration costs

For the levelized cost analysis, Cadmus used the sources shown in Table 18 as well as the sources listed above for technical and achievable technical potential. To calculate the TRC, Cadmus used PSE's inflation rate of 2.5% to adjust future costs to present dollars. We divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes PSE's average line loss factor of 7.8%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (which were assumed to be zero).

Table 18. Combined Heat and Power Levelized Cost Data Sources

Input	Source
State Cost Adjustment	RSMeans
Inflation and Discount Rate	PSE
Natural Gas Rates and Rate Forecasts	PSE
Installed Cost	U.S. Environmental Protection Agency. September 2017. "Catalog of CHP Technologies." https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf
O&M Cost	Itron. October 2015. *2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Appendix A. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/7889-20151119finalfullreport-1-.pdf
PSE Incentive	Puget Sound Energy. Last updated 2022. "Cogeneration/Combined Heat and Power (CHP)." https://www.pse.com/business-incentives/commercial-retrofit-grants/combined-heat-and-power
Program Administration Cost	PSE

Combined Heat and Power Technical Potential Results

Cadmus calculated technical CHP potential for new installations based on sources given above, including C&I customer data along with data on farms, landfills, and wastewater treatment facilities within PSE's service area. This resulted in a total estimated 27-year, system-wide technical potential of 230 aMW. Table 19 details technical potential by area, sector, and fuel. These results exclude previously installed CHP capacity throughout PSE's territory.[21]

20 Puget Sound Energy. Last updated 2022. "Cogeneration/Combined Heat and Power (CHP)." https://www.pse.com/business-incentives/commercial-retrofit-grants/combined-heat-and-power

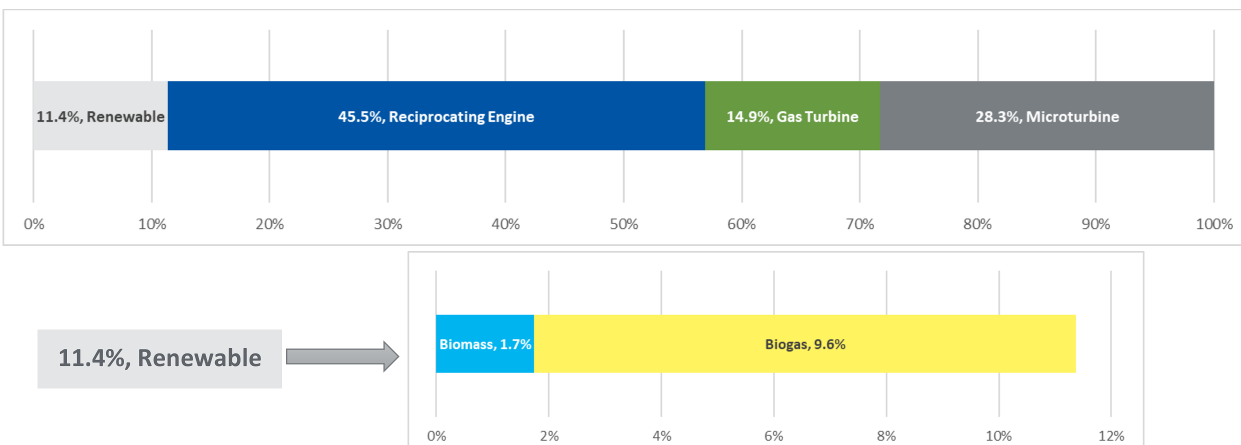
21 U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power Installation Database." https://doe.icfwebservices.com/chpdb/

Table 19. Combined Heat and Power Technical Potential by Sector and Fuel (Cumulative in 2050)

PSE	Technical Potential
Commercial	
Natural gas aMW	142
Number of sites	1,528
Industrial	
Natural gas aMW	62
Number of sites	322
Biomass and biogas aMW	26
Number of sites	45
Industrial total aMW	88
Industrial total number of sites	367
Total	
Total aMW	230
Total number of sites	1,895

Cadmus divided total potential into different technologies (reciprocating engines, microturbines, natural gas turbines for natural gas–fueled systems, and renewables as biogas and biomass). Figure 20 shows the distribution of technical potential as a percentage of 2050 technical potential in average megawatts by these different technologies.

Figure 20. Percentage of 2050 Combined Heat and Power Technical Potential by Technology (in aMW)



Combined Heat and Power Achievable Technical Potential Results

Cadmus applied a market penetration rate of 0.20% per year to the technical potential data to determine achievable technical potential or likely installations in future years. We based the assumed annual market penetration rate on secondary research of naturally occurring CHP installations in the region and on other CHP potential study reports, as described above. As shown in Table 20 and Table 21, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with achievable technical potential over the next 27 years. Cadmus estimated a cumulative 2050 achievable technical potential of 7.91 aMW (9.89 MW of installed capacity) at the generator using PSE's line loss assumption of 7.8%.

Table 20. Combined Heat and Power 2050 Cumulative Achievable Technical Potential Equipment Installations

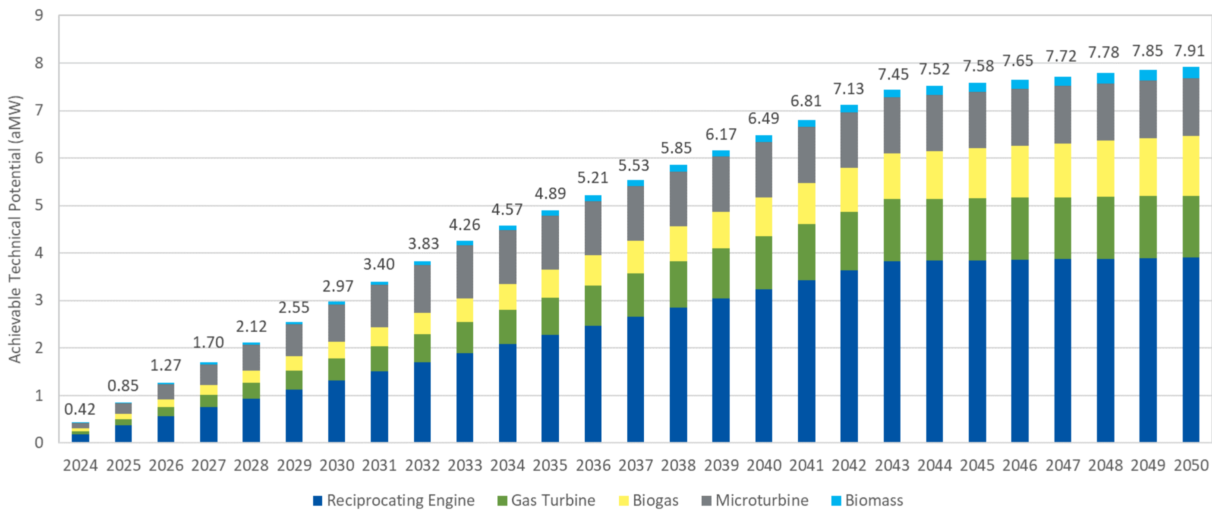
Technology	2050 Installs
Nonrenewable - Natural Gas (Total)	**49**
Reciprocating Engine	25
Gas Turbine	21
Microturbine	2
Renewables	**1**
Total CHP	**50**

Table 21. Combined Heat and Power 2050 Cumulative Achievable Technical Potential at Generator

Technology	2050 aMW	2050 MW
Nonrenewable - Natural Gas (Total)		
30–99 kW	1.15	1.43
100–199 kW	0.93	1.16
200–499 kW	1.19	1.48
500–999 kW	0.86	1.07
1–4.9 MW	1.33	1.66
5 MW+	0.98	1.23
Renewable - Biomass (Total)		
<500 kW	0.00	0.00
500–999 kW	0.00	0.00
1–4.9 MW	0.00	0.00
5 MW+	0.22	0.28
Renewable - Biogas (Total)		
Landfill	0.23	0.28
Farm	0.91	1.14
Paper Manufacturing	0.09	0.11
Wastewater	0.04	0.04
Total CHP	**7.91**	**9.89**

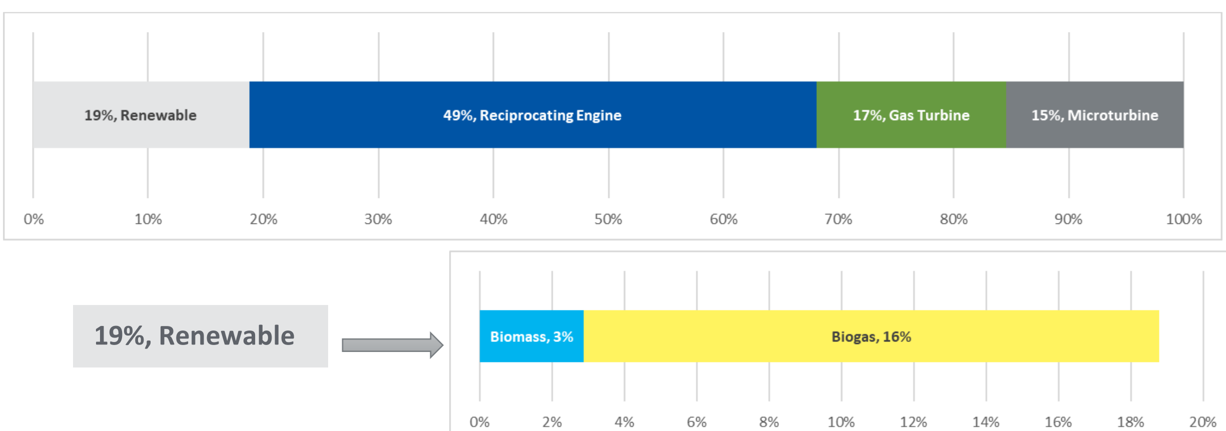
Figure 21 shows cumulative achievable CHP potential by year and technology. The decrease in the rate of adoption at year 2034 is caused by the assumed 10-year lifespan of microturbines. Further decrease in the adoption rate at year 2044 is observed due to the assumed 20-year lifespan of reciprocating engines and natural gas turbines. All three of these technologies are installed throughout the study horizon (2024 through 2050); microturbines do not begin to be decommissioned until 10 years after the start of the study, while reciprocating engines and natural gas turbines begin to be decommissioned 20 years after the start of the study. For microturbines, the rate for the first 10 years of the study is based on new installs and the rate after the first 10 years includes new installs as well as decommissioned systems. Similarly, for reciprocating engines and natural gas turbines, the rate for the first 20 years of the study is based on new installs and the rate after the first 20 years includes new installs as well as decommissioned systems.

Figure 21. Combined Heat and Power Cumulative Achievable Technical Potential by Year at Generation (aMW)



Of the 7.91 aMW of cumulative achievable technical potential, reciprocating engines made up 3.90 aMW (49%), natural gas turbines made up 1.31 aMW (17%), and microturbines made up 1.22 aMW (15%). The remaining 19% was for renewable technologies, which consisted of biogas (1.26 aMW) and biomass (0.23 aMW) systems. In 2050, total energy generated across all technologies is 69.3 GWh (with nonrenewable at 56.3 GWh and renewables at 13 GWh). Figure 22 shows the market potential of energy generation by each technology.

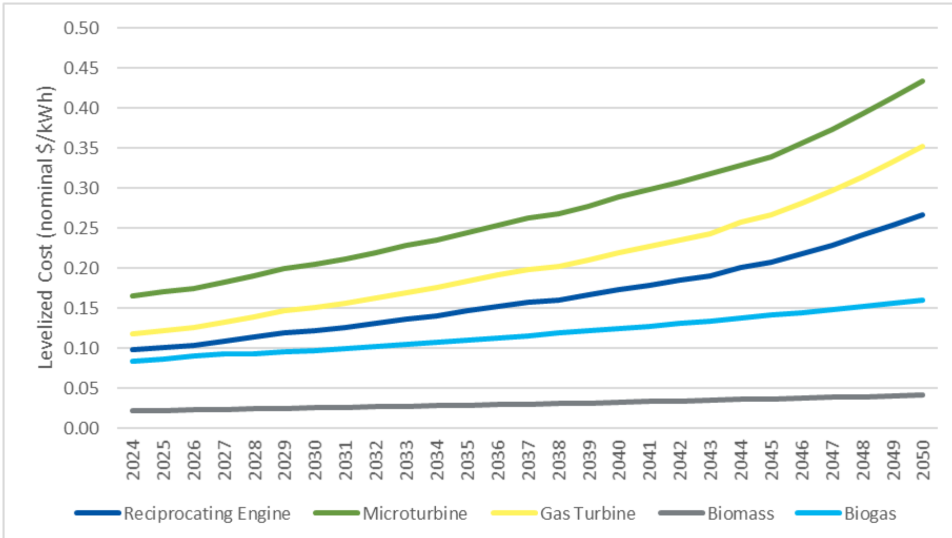
Figure 22. Breakout of Combined Heat and Power 2050 Cumulative Achievable Technical Potential



Combined Heat and Power Levelized Cost Results

Cadmus calculated the levelized cost, based on the TRC perspective, for each technology configuration in each installation year (2024 through 2050). Figure 23 shows the nominal levelized cost for units installed through the study period. The levelized cost increases over time. For nonrenewable systems, the levelized cost increase results from increasing natural gas prices and inflation. For the renewable systems, the levelized cost increase results from inflation.

Figure 23. Nominal Levelized Cost by Technology and Installation Year



Chapter 2. 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 DLC programs) or offer pricing structures to induce participants to shift load away from peak periods (such as critical peak pricing [CPP] programs).

Overview of Technical and Achievable Technical Potential Approach

Cadmus focused on programs aimed at reducing PSE's winter and summer peak demand. These programs include residential and commercial DLC HVAC, residential DLC water heat, residential 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 ERWH. A water heater can also be grid-enabled or controlled by a switch.

We defined each demand response program and its associated product option(s) according to typical program offerings, with particular specifications such as program implementation methods, applicable segments, affected end uses, load reduction strategies, and incentives. The program assumptions are based on the inputs used in the draft *2021 Power Plan* with a few modifications to account for additional benchmarking.

Technical Potential Approach

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, Cadmus applied either a bottom-up or a top-down method to estimate technical potential.

Cadmus used the bottom-up method to assess potential for demand response programs that affect a piece of equipment in a specific end use, such as residential and commercial DLC space heat, residential DLC water heat, and residential EVSE. In the bottom-up method, we determined technical potential as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kilowatt) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. Cadmus began these calculations by disaggregating system electricity sales by sector, market segment, and end use, then we estimated technical potential as a fraction of the end-use loads. Cadmus then estimated total potential by aggregating the estimated load reductions of the applicable end uses. We applied the top-down estimation method to demand response products that target the entire facility or load (rather than specific equipment), such as CPP and C&I demand curtailment.

Achievable Technical Potential Approach

Achievable technical potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable technical potential: market acceptance (or the participation rate) and the ramp rate. The participation rate is also broken down into program participation (the likelihood of the eligible population to enroll in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event)—an important consideration in voluntary demand response programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate when the maximum achievable technical potential may be reached, but they do not affect the amount of maximum achievable technical potential.

Both the top-down and bottom-up methods calculate achievable technical potential as the product of technical potential and market acceptance. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Levelized Costs Calculations

In the context of demand response, the levelized cost of electricity represents the constant per-kilowatt-year cost of deploying and operating a demand response product, calculated as follows:

$$Levelized\ Cost\ of\ Electricity = \frac{Annualized\ Cost\ of\ Demand\ Response\ Product}{Achievable\ Annual\ Kilowatt\ Load\ Reduction}$$

Cadmus calculated levelized costs based on the TRC perspective, which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant, direct costs of a demand response product, including setup costs, program O&M costs, equipment cost, marketing cost, incentives, T&D deferral costs, a discount rate, and the product life cycle:

- **Upfront setup cost.** This cost item includes PSE's program development and setup costs for delivery of demand response products, prior to program implementation. Because upfront costs tend to be small relative to total program expenditures, they are expected to have a small effect on levelized costs.
- **Program O&M cost.** This cost item includes all expenses that PSE incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and recruiting new loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable demand response technology for each participating end user. This cost item only applies to each year's new participants. For programs that assume or require end users to already have demand response technology in place, this cost item would be zero.

- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and only applies to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incentive.** This cost item covers all incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. Cadmus only included a portion of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation. We followed the same approach used by the Council in the draft *2021 Power Plan*, following protocols outlined in the *California Standard Practice Manual* and further modified by the DRAC and Council staff.
- **T&D costs.** Cadmus included a T&D deferral value of $74.70 per kilowatt-year as a negative cost item in the levelized cost calculations for each product.
- **Discount rate.** Cadmus used a 6.8% discount rate for all demand response products, consistent with PSE's resource planning assumptions.
- **Product life cycle.** Based on equipment control lifetimes, the life cycles for products with enabling equipment are limited by the enablement technology's effective useful life (EUL). For example, a BYOT program's product life cycle is equivalent to the EUL of a smart thermostat. All product life cycles were determined in this way except for pricing products: because these are based on rate structures, we assumed the program would be the length of the study duration.

Supply Curve Development

Demand response supply curves show the quantity-price relationships for the demand response products that are being considered at the end of the planning period. A supply curve shows the incremental and cumulative achievable technical potential for a set of demand response products, in the ascending order of their levelized costs.

Demand Response Potential

This section introduces the analysis scope for assessing demand response potential in PSE's electric service territory, followed by a summary of potential results of the demand response programs and detailed descriptions of each program, including the product options and associated input assumptions.

Scope of Analysis

Focused on reducing a utility's capacity needs, demand response programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

Demand response objectives may be met through a broad range of strategies, both price-based (such as CPP) and incentive-based (such as DLC) strategies. For this assessment, Cadmus considered 15 total demand response product options to estimate total achievable technical demand response potential in PSE's service area during peak load in winter and summer. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses as well as EVSE and C&I products such as demand curtailment contracts and CPP. In this study, event durations are defined as 40 hours per season (with 10, four-hour events per season).

Cadmus relied on the Council's draft *2021 Power Plan* and we reviewed recent demand response literature, including evaluations of pilots and programs in the Northwest and across the country, to determine the design for each demand response program. The product groups in this study often have multiple product options to capture the most common demand response product strategies. For example, customers participating in the residential DLC space heat program can either have a switch installed on the HVAC system in their home or let the utility communicate with the home's existing smart thermostat.

Summary of Resource Potential

Table 22 lists the estimated resource potentials for all winter demand response programs for the residential, commercial, and industrial sectors. The greatest achievable technical potential occurs in the residential sector from the DLC programs (for HVAC and water heat). Note that this analysis accounts for program interactions and overlap; therefore, the total achievable technical potential estimates are additive.

Table 22. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Winter 2050

Program	Product Option	Winter Achievable Technical Potential (MW)	Winter Percentage of System Peak	Levelized Cost ($/kW-year)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0.00%	$24
	Residential ERWH DLC Grid-Enabled	32	0.52%	-$28
	Residential HPWH DLC Switch	0	0.00%	$203
	Residential HPWH DLC Grid-Enabled	58	0.94%	$91
Residential DLC HVAC	Residential HVAC DLC Switch	97	1.56%	-$24
	Residential BYOT DLC	108	1.74%	-$56
Residential DLC EVSE	Residential EVSE DLC Switch	42	0.67%	$105
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	18	0.30%	-$33
	Small Commercial HVAC DLC Switch	3	0.04%	$0
	Small Commercial BYOT DLC	3	0.05%	-$36
C&I Curtailment	Commercial Curtailment	16	0.26%	-$28
	Industrial Curtailment	5	0.08%	-$37
Residential CPP	Residential CPP	33	0.54%	-$56
Commercial CPP	Commercial CPP	21	0.34%	-$57
Industrial CPP	Industrial CPP	2	0.02%	-$34
-	**Total**	**439**	**7.05%**	**NA**

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 23. The remainder of the results presented in this chapter focus on the winter demand response potential.

Table 23. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Summer 2050

Program	Product Option	Summer Achievable Technical Potential (MW)	Summer Percentage of System Peak	Levelized Cost ($/kW-year)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0.00%	$74
	Residential ERWH DLC Grid-Enabled	22	0.39%	-$4
	Residential HPWH DLC Switch	0	0.00%	$481
	Residential HPWH DLC Grid-Enabled	29	0.53%	$257
Residential DLC HVAC	Residential HVAC DLC Switch	50	0.90%	$52
	Residential BYOT DLC	100	1.81%	-$40
Residential DLC EVSE	Residential EVSE DLC Switch	42	0.75%	$105
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	77	1.40%	-$42
	Small Commercial HVAC DLC Switch	5	0.10%	$64
	Small Commercial BYOT DLC	4	0.07%	-$3
C&I Curtailment	Commercial Curtailment	20	0.36%	-$28
	Industrial Curtailment	5	0.09%	-$37
Residential CPP	Residential CPP	74	1.35%	-$66
Commercial CPP	Commercial CPP	26	0.48%	-$61
Industrial CPP	Industrial CPP	2	0.03%	-$35
-	**Total**	**455**	**8.24%**	**NA**

Cadmus constructed supply curves from quantities of estimated achievable technical demand response potential and per-unit levelized costs for each product option. Figure 24 shows the achievable technical potential (available during the system winter peak hours in 2050) as a function of levelized costs at the product option level.

The supply curve starts with the lowest cost product option—commercial CPP, which provides 21 MW of winter achievable technical potential at -$57 per kilowatt-year, levelized. The next lowest-cost product in the supply curve is the residential CPP product, which adds 33 MW of winter achievable technical potential at -$56 per kilowatt-year, levelized. Thus, PSE could acquire a total of 55 MW (with rounding) of winter demand response at a negative levelized cost.

These two most cost-effective demand response product options have negative costs due to the inclusion of deferred T&D costs in the TRC levelized cost calculation. Cadmus incorporated a T&D deferral value of $68.13 per kilowatt-year as a negative cost item in the levelized cost calculations for each product, resulting in negative net levelized costs for the majority of products.

Because residential EV DLC is the most expensive product option (with non-zero final year potential), PSE could acquire as much winter potential as achievable if it paid $105 per kilowatt-year (the levelized cost for the most expensive product option). However, PSE could acquire approximately 77% of the total achievable technical winter demand response potential at $0 per kilowatt-year or less due to the high deferred T&D costs.

Figure 24. Demand Response Achievable Technical Potential Supply Curve by Product Option, Winter

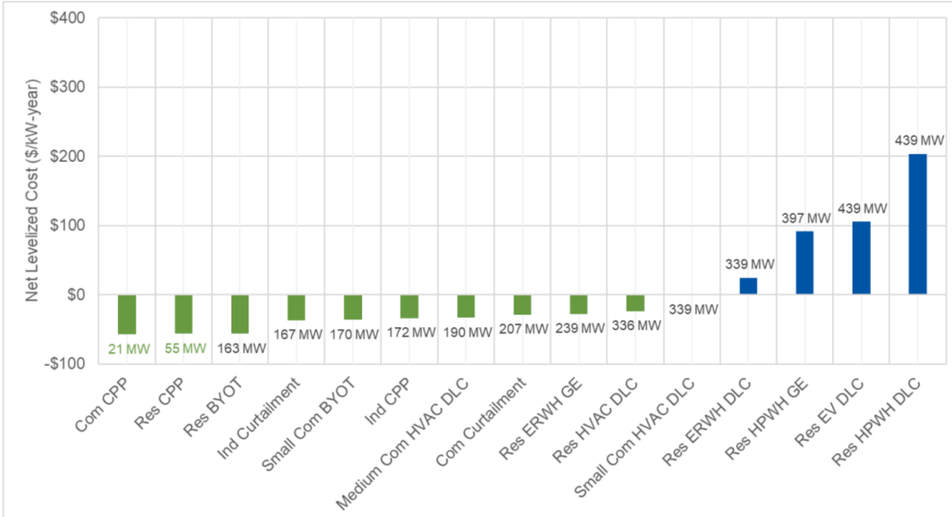


Figure 25 shows the acquisition schedule for achievable technical potential by product for winter. Product potential ramps up in the early years of the study by recruiting new participants and flatten out once market has reached maturity. For example, residential HVAC and water heating DLC make up much of the available winter demand response potential once the demand response market matures. It should be noted the demand response potential shown represents the achievable technical potential and includes both cost effective and non-cost effective demand response products.

Figure 25. Demand Response Achievable Technical Potential Forecast by Program, Winter

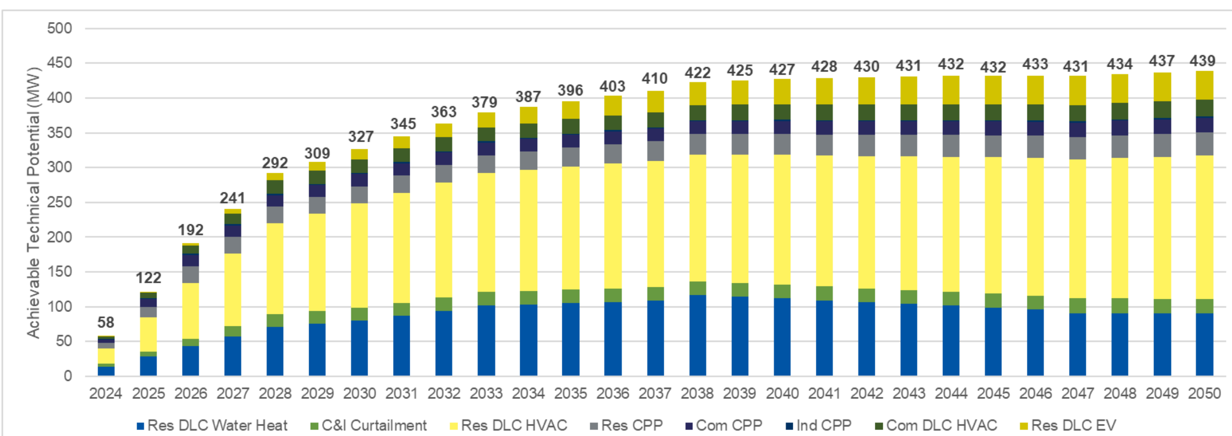
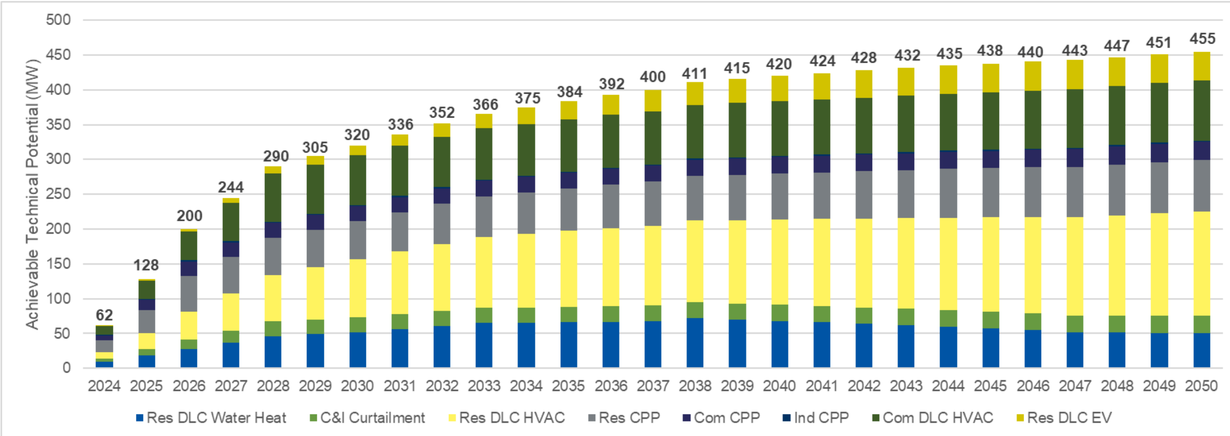


Figure 26 shows the acquisition schedule for achievable technical potential by program for summer. The dynamics in the summer are similar to those seen in the winter, though there are some key differences. For example, the water heating per unit peak demand impacts in the summer are lower compared to the winter per unit impacts. As a result, the overall potential is lower for water heating in the summer. Conversely, the commercial HVAC DLC and residential CPP also have more potential in summer than in the winter.

Figure 26. Demand Response Achievable Technical Potential Forecast by Program, Summer



Chapter 3. Rooftop Solar PV Potential

This chapter includes a discussion of the methodology and inputs for estimating technical and achievable technical rooftop solar PV potential, as well as the potential results for the commercial and residential sectors and vulnerable population segment.

Overview of Technical and Achievable Technical Potential Approach

This section describes the technical and achievable technical potential for rooftop solar PV (not including ground-mounted solar PV systems). Figure 27 briefly describes these potential estimate types.

Figure 27. Types of Estimated Potential

<table>
<tr><td>Rooftop Area Not Suitable for Development</td><td colspan="2">TECHNICAL POTENTIAL
Theoretical maximum system (nameplate) capacity deployed and energy produced accounting for available rooftop square footage including shading, solar PV panel production per square foot, and solar irradiation.</td></tr>
<tr><td>Rooftop Area Not Suitable for Development</td><td>Not Adopted by Building Owners</td><td>ACHIVABLE TECHNICAL POTENTIAL
Rooftop solar capacity deployed and energy produced based on simulations and economic parameters that affect the financial attractiveness from a customer perspective.</td></tr>
</table>

Technical Potential Approach

Technical potential represents the theoretical maximum developable rooftop solar PV capacity given the statewide rooftop square footage. Technical capacity potential excludes rooftop areas that are not suitable for development.[22] Technical energy production potential accounts for solar irradiation across PSE service territory and is measured in kilowatt-hours, megawatt-hours, or gigawatt-hours.

Technical potential is calculated by the dGen model using light detection and ranging data to calculate rooftop obstructions, rooftop azimuth, and rooftop tilt. The model also assumes that a percentage of the building stock is not suitable for rooftop solar development based on rooftop orientation or pitch. Finally, the model mines regional solar irradiation levels to calculate technical potential. Technical potential does not account for barriers to adoption, such as roof age, structural suitability, or electric code compliance.

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22 To be considered suitable for development, a roof plane is required to be at least 80% unshaded and it cannot be oriented to the northwest, north, or northeast. The dGen model does not account for changes in shading over time.

Achievable Technical Potential Approach

Achievable technical potential represents the simulated rooftop solar PV adoption on residential and commercial buildings and is based on three parameters:

- Existing rooftop solar deployment in an area of interest
- The assumed maximum market adoption based on the economic attractiveness of solar PV systems
- The technology diffusion rate throughout the population

Existing rooftop solar deployment refers to the historically adopted system capacity in PSE territory, by sector, through 2022. Economic attractiveness is a function of a range of model inputs, including technology costs, federal and state incentives, project financing, and utility compensation mechanisms (net metering or net billing). The technology diffusion rate throughout the population refers to the rate of adoption of rooftop solar PV and is determined by a Bass diffusion curve.

The Bass diffusion curve is determined by Bass diffusion coefficients, a key input used to simulate technology diffusion. For this study Cadmus recalibrated the Washington coefficients in the dGen model to PSE service territory trends based on historical adoption data.

Another key input impacting adoption is the maximum market adoption curve, used to provide the relationship between the maximum percentage of the market that adopts solar and the payback period. Achievable technical potential is a subset of technical potential, determined by the adoption parameters described above and limited by the amount of solar potential that can technically be installed given suitable rooftop space.

Methodology

This section describes the methodology and model inputs Cadmus used to estimate technical and achievable technical potential.

NREL dGen Model

To model technical potential and to simulate achievable rooftop solar PV potential, Cadmus used NREL's dGen model, which simulates the market adoption of rooftop solar PV systems. The model and underlying state-level datasets are available to the public. The dGen model uses a particular approach to estimate market adoption:

NREL has made the model publicly available and provides the opportunity to adjust model inputs and underlying assumptions, as well as model logic. Cadmus reviewed the model inputs in detail and adjusted data inputs and model programming as appropriate. Details about the model mechanics can be found in the dGen documentation as well as on the NREL website at https://www.nrel.gov/analysis/dgen/

- Generates agents and assigns representative attributes based on population data[23]
- Applies technical resource characteristics—such as solar irradiance, rooftop square footage, rooftop pitch and orientation, and obstruction data—to each agent
- Conducts economic calculations using cash flow analysis and incorporating project costs, electric rates, net-metering or net billing considerations, and state and federal incentives
- Calculates market adoption based on Bass diffusion and project economics[24]

The dGen model provides market adoption results at the county, utility, and state levels. The model also produces estimates by sector and building segment through 2050.[25] Because model inputs can be varied, adoption scenarios can be generated by changing key inputs.

Approach for Technical Potential

The dGen model uses light detection and ranging data inputs to estimate the total rooftop area suitable for solar projects and calculates system capacity factors based on additional data inputs such rooftop orientation and solar irradiance. However, the model does not directly report technical potential estimates; rather, its outputs can be used to calculate the amount of capacity that could be deployed and amount of energy that could be produced. To calculate technical potential, Cadmus applied the system capacity per square footage model input assumption to the estimated developable rooftop (see the *Model Inputs* section for more details).[26] The technical system capacity changes over time based on assumed increases in solar panel efficiency and load growth associated with new buildings. To calculate

23 An agent represents a group of customers with similar characteristics for the purpose of estimating solar adoption. Agents are statistically weighted together to represent commercial and residential populations.

24 National Renewable Energy Laboratory (Sigrin, Benjamin, Michael Gleason, Robert Preus, Ian Baring-Gould, and Robert Margolis). February 2016. "The Distributed Generation Market Demand Model (dGen): Documentation."

25 While aggregate outputs are available at various levels of granularity, these cannot necessarily be provided at any special resolution due to the sampling approach taken to generate population files. For example, building sector resolution is not available at the county level because not all counties include all building sectors in the sample-based population file.

26 The NREL dGen model does not account for roof age, structural suitability, or electric code compliance. These factors can create barriers to solar adoption, especially for income-qualified customers.

technical generation potential, Cadmus applied the modeled system capacity factors to the calculated technical system capacity.

Approach for Vulnerable Populations

The dGen model does not simulate market adoption for vulnerable populations and does not characterize agents (representative customers) by vulnerability level. To generate vulnerable population estimates, Cadmus segmented the residential population into standard income and vulnerable population groups using PSE's *Residential Consumption Survey*. After reviewing survey data Cadmus found that only 3% of vulnerable population households had solar (we used a proxy of annual household incomes below $50,000 to identify vulnerable populations because a vulnerable population identifier was not available in the dataset). Accordingly, Cadmus adjusted the historical adoption of solar systems to reflect that adoption trend and adjusted Bass diffusion coefficients to reflect a much slower market adoption rate compared with the standard-income populations.

Approach for Multifamily Potential

The dGen residential model simulates the adoption of rooftop solar PV on multifamily buildings as a unit occupant decision, rather than a building owner decision. For this study Cadmus assumed that multifamily building rooftop solar potential is part of the commercial sector, given that building owners, rather than unit occupants, are the most likely adopters of rooftop solar systems. To estimate multifamily rooftop solar adoption, Cadmus calculated multifamily building technical potential, then applied an adoption rate from the commercial sector.

Approach for Renters

Cadmus reviewed data from the PSE *Residential Consumption Survey* and found that only 1% of households living in rental units had solar systems installed on their homes (this percentage may include homes where solar was installed before the home became a rental unit, but the data does not specify the situation). The very low adoption of rooftop solar on rental homes is consistent with the theory that the split incentive makes it unlikely that rooftop solar systems will be installed on rental homes. Accordingly, Cadmus removed renters from the agent file and did not simulate adoption for the renter population segment.

Approach for Small Systems

The dGen model sizes systems to achieve the maximum payback for a customer. Because the model sometimes generates system sizes that are unrealistically small, Cadmus removed systems from this analysis that were sized by dGen to be smaller than 1 kW.

Model Inputs

The dGen model contains a large volume of data inputs, including utility rates, customer populations, customer loads, project costs, financing conditions, and many others. Table 24 provides key dGen model inputs for the commercial and residential baseline models. For the vulnerable population residential model, Cadmus adjusted the market diffusion coefficients and kept the other residential inputs constant. The dGen model provides prepopulated tables with the model inputs, which are applied universally to all members of the population.

Table 24. Baseline Model Inputs

Model Input	Value	Notes/Source
Residential		
Federal investment tax credit	2020–2022: 26%; 2023: 22%; after 2023: 0%	U.S. Department of Energy
Loan term	30 years	NREL 2021 annual technology baseline (ATB) [a]
Interest rate	3.96%	NREL 2021 ATB [a]
Discount rate	3.67%	NREL 2021 ATB [a]
Down payment fraction	24.2%	NREL 2021 ATB [a]
Net metering	2022–2050	Set net metering through 2050 following discussions with PSE that other incentives would likely begin when PSE net-metering sunsets in 2029.
Solar costs (2021)	$3,197 per kilowatt	2021 costs are based on historical PSE program costs. Costs decline according to NREL 2021 ATB [a] "moderate" estimates.
Coefficient: *p* (innovation)	0.001	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *q* (imitation)	0.25	
Residential Vulnerable Population Adjustment		
Coefficient: *p* (innovation)	0.0002	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *p* (innovation)	0.005	
Commercial		
Federal investment tax credit	2020–2022: 26%; 2023: 22%; after 2023: 10%	U.S. Department of Energy
Loan term	30 years	NREL 2021 ATB [a]
Interest rate	3.96%	NREL 2021 ATB [a]
Discount rate	1.83%	NREL 2021 ATB [a]
Down payment fraction	24.1%	NREL 2021 ATB [a]
Net-metering	2022–2050	Set net metering through 2050 following discussions with PSE that other incentives would likely begin when PSE net-metering sunsets in 2029.
Solar costs (2021)	$1,677 per kilowatt	2021 costs are based on PSE program data. Costs decline according to NREL 2021 ATB [a] "moderate" estimates.
Coefficient: *p* (innovation)	0.0012	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *q* (imitation)	0.16	

[a] National Renewable Energy Laboratory. Accessed May 2022. "Electricity Annual Technology Baseline (ATB) Data Download." https://atb.nrel.gov/electricity/2021/data

Another modeling consideration is the distributed rooftop system adoption that has been historically deployed. These data provide a starting point for future simulated rooftop adoption. A key consideration is that each utility has specific starting points for solar adoption, which are then used as the starting point for future growth within that utility service area. Cadmus used PSE program data for past solar adoption estimates.

Rooftop Solar PV Potential

This section provides the results for technical and achievable rooftop solar potential in PSE service territory.

Technical Potential Results

Based on the analysis described in the *Methodology* section above, Cadmus estimated 20,498 MW as the total technical potential for PV installed on residential and commercial rooftops in PSE's service area through 2050. Much of this technical potential (61%) is in the residential sector and the remaining 39% is from the commercial sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. If the full technical potential were installed, it would generate approximately 2,413 aMW.

Table 25 provides the study period behind-the-meter PV technical potential with growth due to increases in building stock from 2024 to 2050 and increases in solar PV efficiency.

Table 25. Rooftop Solar PV Technical Potential

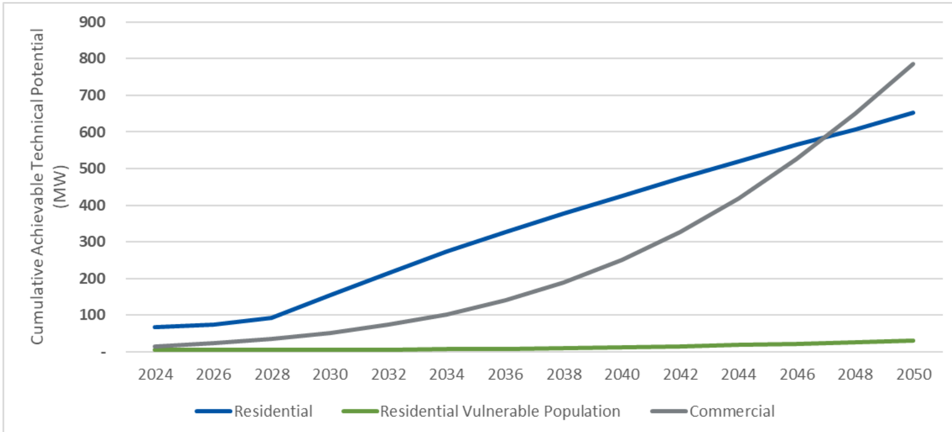
Sector	Total 2024 aMW	Installed Capacity 2024 MW	Total 2050 aMW	Installed Capacity 2050 MW
Residential	622	5,354	952	8,158
Residential - Vulnerable Population	327	2,810	500	4,281
Commercial	494	4,145	960	8,059
Total	**1,443**	**12,308**	**2,413**	**20,498**

Achievable Technical Potential Results

Cadmus simulated achievable technical potential from 2024 through 2050 using NREL's dGen tool, which applies a market diffusion approach under changing market conditions. Figure 28 shows the simulated market adoption trend by sector from 2024 through 2050. In total, the dGen tool predicts that in 2050 the market will adopt 1,423 MW of rooftop solar capacity, or approximately 7% of the estimated technical potential. Vulnerable populations make up a very small fraction of this achievable technical potential (2% of the 2050 total achievable technical potential), while the commercial sector makes up approximately 55% of the achievable technical potential, despite having a lower portion of the technical potential than the residential sector.

Historically, the residential sector has had a higher fraction of installed rooftop solar systems. However, through 2050 the achievable technical potential market adoption simulation shows a leveling off of residential adoption, while the commercial sector shows continued growth through 2050. Contributing factors to this trend include declining economic attractiveness for residential systems due to the phasing out of the federal investment tax credit and the low cost for commercial solar systems through 2050.

Figure 28. Rooftop Solar PV Achievable Technical Potential - Nameplate



In terms of achievable technical potential energy production, the adopted rooftop systems, as simulated by dGen, will produce 11.9 aMW (37.9 MW) in 2024 and increase to 169.9 aMW (1,422.7 MW) in 2050 (Table 26). The achievable 2050 energy production represents 7% of the technical potential for energy production (in average megawatts). The commercial sector has 56% of the achievable 2050 energy production potential (in average megawatts), while the residential sector has 44% of the achievable technical potential (vulnerable populations have 0.3% of the potential).

Table 26. Rooftop Solar PV Achievable Technical Potential

Sector	Total 2024 aMW	Installed Capacity 2024 MW (Nameplate)	Total 2050 aMW	Installed Capacity 2050 MW (Nameplate)
Residential	7.7	29.8	73.5	617.0
Residential Vulnerable Population	0.6	2.6	0.6	28.2
Commercial	3.9	5.5	95.8	777.5
Total	**11.9**	**37.9**	**169.9**	**1,422.7**

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.

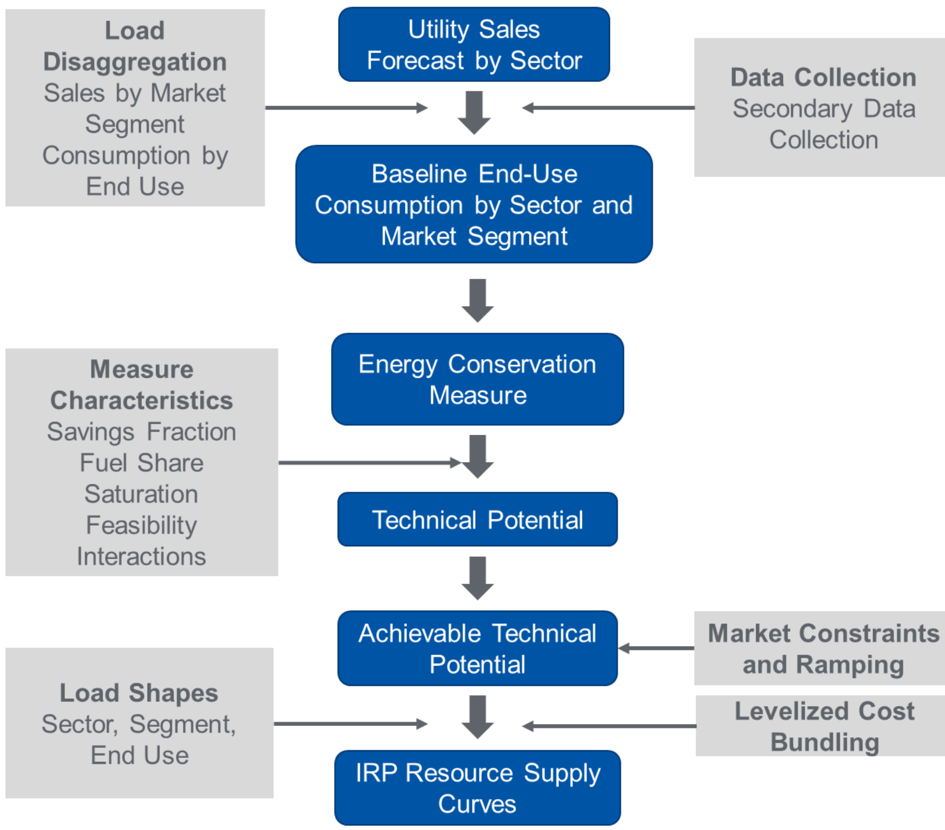
Cadmus followed a series of steps to estimate energy efficiency potential, described in detail in the subsections below:

- ***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 29 provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

Figure 29. Overview of Energy Efficiency Methodology



Market Segmentation

Market segmentation involved first dividing PSE's electric 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 RCS.

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

- ***Service territories and fuel type.*** PSE's electric service territory
- ***Sector.*** Residential, commercial, and industrial
- ***Industries and building types.*** Three residential segments (and the corresponding vulnerable population segments), 18 commercial segments including indoor agriculture, and 21 industrial segments including water supply and sewage treatment and streetlighting

Table 27 lists the segments modeled for each sector.

Table 27. Segments Modeled

Residential	Commercial	Industrial
• Single Family • Multifamily • Manufactured • Multifamily - Vulnerable Population • Manufactured - Vulnerable Population • Single Family - Vulnerable Population	• Large Office • Medium Office • Small Office • Extra Large Retail • Large Retail • Medium Retail • Small Retail • School K–12 • University • Warehouse • Supermarket • Mini-Mart • Restaurant • Lodging • Hospital • Residential Care • Assembly • Other • Indoor Agriculture	• Mechanical Pulp • Kraft 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 • Streetlighting • Sewage Treatment • Water Supply

Energy Conservation 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
- All measures in the Council's draft *2021 Power Plan* conservation supply curve workbooks
- Active UES measures in the RTF

Cadmus included only the Council and RTF measures applicable to sectors and market segments in PSE's service territory. For example, we did not characterize measures for the agriculture sector except indoor agriculture measures such as lighting. Cadmus added measures if the RTF workbooks were not included in the Council's draft *2021 Power Plan* or if the RTF workbooks had been updated since the Council's draft *2021 Power Plan* workbooks.

Cadmus classified the electric 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 domestic water heaters), 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 had several relevant inputs.

Equipment and non-equipment measures:

- Energy savings: Average annual savings attributable to installing the measure, in absolute (kilowatt-hour 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 (NEIs): The annual dollar savings per year associated with quantifiable non-energy benefits
- Savings shape: The hourly savings shape for each measure, which Cadmus assigned and then used to disaggregate annual forecasts of potential into hourly 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, equal to 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 (such as a decrease in lighting power density causing heating loads to increase)

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 Council's draft *2021 Power Plan* conservation supply curve workbooks
- The RTF UES measure 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. The Council's draft *2021 Power Plan* conservation supply curve workbooks, except in cases where a more recent version of RTF UES measure workbooks were submitted and not used in the Council's draft *2021 Power Plan*
3. RTF UES measure workbooks
4. Secondary sources, such as American Council for an Energy-Efficient Economy work papers, Simple Energy and Enthalpy Model building simulations, 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 2021 CPA to calculate NEIs, which resulted in additional NEIs for more measures. In 2021, PSE conducted an NEI evaluation study[27] to expand the NEIs; the full list is shown in Table 28.

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

Table 28. 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 associated with electricity generation at power plants (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, heat/cold stress, and other, 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, as well as 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 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 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). Also includes modeled value of decreased usage of fuel, propane, and other sources
Product Spoilage/Defects	Participant	Participant-reported value of avoided product losses (such as reduced food spoilage in grocery stores)

NEI Name	NEI Type	Definition
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 even temperatures throughout the building
Waste Disposal	Participant	Participant-reported costs to remove solid waste and 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 draft *2021 Power Plan* and RTF UES workbooks when a business case was not available for a measure and some RTF and Council measures already had NEIs such as water savings, O&M, and lifetime replacement. Therefore, Cadmus developed the methodological hierarchy presented in Table 29 to account for all available NEI data for all measures applicable.

Table 29. 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 savings, O&M, and lifetime replacement), if applicable
RTF/Council without existing NEI	Use NEI evaluation study data, if applicable

Measure Data Sources

By data input, Table 30 lists the primary sources referenced in the study.

Table 30. Key Measure Data Sources

Data	Residential Source	Commercial Source	Industrial Source
Energy Savings	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	Draft *2021 Power Plan* supply curve workbooks
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	Draft *2021 Power Plan* supply curve workbooks
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	Draft *2021 Power Plan* supply curve workbooks
Technical Feasibility	NEEA RBSA; Cadmus research	NEEA CBSA; Cadmus research	Cadmus research; Council's industrial data
Percentage Incomplete	NEEA RBSA; PSE program accomplishments; Cadmus research	NEEA CBSA; PSE program accomplishments; Cadmus research	Cadmus research; Council's industrial data

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; [a] draft *2021 Power Plan* supply curve workbooks; RTF	PSE business cases; PSE's NEI evaluation study; [a] draft *2021 Power Plan* supply curve workbooks; RTF	Draft *2021 Power Plan* supply curve workbooks

[a] 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 and cooling equipment, lighting, water heating, motors, and other appliances not covered in or superseded by state and local codes.[28]
- **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 from using electric resistance or fossil fuels for water heating effective January 1, 2022. All other code provisions took effect on March 15, 2021.[29]
- **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 the Washington code, effective February 1, 2021.[30]
- **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."

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28 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

29 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

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

- **2018 Revised Code of Washington (RCW 19.260.040).** This code set minimum efficiency standards to specific types of products including computers, monitors, showerheads, faucets, residential ventilation fans, general service lamps, air compressors, uninterruptible power supplies, water coolers, portable air conditioners, high color rendering index fluorescent lamps, commercial dishwashers, steam cookers, hot food holding cabinets, and fryers. The effective dates vary by product with the 2018 RCW Revised Code of Washington signed on July 28, 2019.[31]
- **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 Washington Energy Code as adopted by the Building Council in Chapter 51-11 of the WAC 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, the Clean Buildings bill, and CETA) 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 (Seattle Municipal Code 22.920).** This program requires owners of commercial and multifamily buildings (20,000 square feet or larger) to annually track and report energy performance to the city of Seattle. Though in effect since 2016, full enforcement of the program began on January 1, 2021.[32]
- **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

31 Washington State Legislature. December 7, 2020. *Revised Code of Washington*. "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

32 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#:~:text=Seattle's%20Energy%20Benchmarking%20Program%20(SMC,to%20the%20City%20of%20Seattle.&text=Compare%20your%20building's%20energy%20performance,started%20saving%20energy%20and%20money

buildings, especially large commercial buildings (based on building square feet), and to provide incentives to encourage efficiency improvements. The effective date is July 28, 2019, with the building compliance schedule set to begin on June 1, 2026. Early adopter incentive applications began in July 2021.[33]

- **Clean Energy Transformation Act (194-40-330).** This act applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach the required 100% clean electricity supply. The first milestone was in 2022, when each utility must have prepared and published a clean energy implementation plan with its own targets for energy efficiency and renewable energy.[34]

Treatment of Federal Standards

Cadmus explicitly accounted for several other pending federal codes and standards. For the residential sector, these included appliance, HVAC, and water-heating standards. For the commercial sector, these included appliance, HVAC, lighting, motor, and water-heating standards. Table 31 provides a comprehensive list of equipment standards we considered in this study. However, Cadmus did not attempt to predict how energy standards might change in the future.

Table 31. Electric Federal and State 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
Computer	State standard 2019	Nonresidential/Residential	January 1, 2021
Dehumidifier	Federal standard 2012	Residential	October 1, 2012
	Federal standard 2019		June 13, 2019
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
Uninterruptible (External) Power Supply	Federal standard 2016	Nonresidential/Residential	February 10, 2016
	Federal standard 2017		July 1, 2017
	State standard 2019		January 1, 2021
Freezer	Federal standard 2014	Residential	September 15, 2014
Microwave	Federal standard 2016	Residential	June 17, 2016
Fryer and Steam Cooker	State standard 2019	Nonresidential	January 1, 2021
Refrigerator	Federal standard 2014	Residential	September 15, 2014
Automatic Commercial Ice Maker	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2018		January 28, 2018

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

34 Washington State Department of Commerce. Accessed July 2022. "Clean Energy Transformation Act." https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Commercial Refrigeration Equipment (semi-vertical and vertical cases)	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2012		January 1, 2012
	Federal standard 2017		March 27, 2017
Vending Machine	Federal standard 2012	Nonresidential	August 31, 2012
	Federal standard 2019		January 8, 2019
Walk-In Cooler	Federal standard 2014	Nonresidential	August 4, 2014
Walk-In Freezer	Federal standard 2017		June 5, 2017
Central Air Conditioner	Federal standard 2015 (no change for Northern region)	Residential	January 1, 2015
Heat Pump (air source)	Federal standard 2015	Residential	January 1, 2015
Packaged Terminal Air Conditioner and Heat Pump	Federal standard 2012	Nonresidential	October 8, 2012
	Federal standard 2017		January 1, 2017
Room Air Conditioner	Federal standard 2014	Residential	June 1, 2014
Single Package Vertical Air Conditioner and Heat Pump	Federal standard 2010 (phased in over six years)	Nonresidential	January 1, 2010
	Federal standard 2019		September 23, 2019
Small, Large, and Very Large Commercial Package Air Conditioner and Heat Pump	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2018		January 1, 2018
	Federal standard 2023		January 1, 2023
Fluorescent Lamp Ballast	Federal standard 2014	Nonresidential	November 14, 2014
General Service Fluorescent Lamp	Federal standard 2012	Nonresidential	July 14, 2012
	Federal standard 2018		January 26, 2018
Lighting General Service and Specialty Lamp	State standard 2019	Nonresidential/Residential	January 1, 2021
Metal Halide Lamp Fixture	Federal standard 2017	Nonresidential	February 10, 2017
Electric Motor (small)	Federal standard 2015	Nonresidential	March 9, 2015
Electric Motor	Federal standard 2010	Nonresidential	December 19, 2010
	Federal standard 2016		June 1, 2016
Furnace Fan	Federal standard 2019	Residential	July 3, 2019
Pump	Federal standard 2020	Nonresidential	January 27, 2020
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 two considerations that impacted the characterization of this potential study. Starting with residential lighting, Cadmus reviewed the codes and standards and assessed the current situation related to LED lighting.

The Council's draft *2021 Power Plan* and RTF residential lighting workbooks account for the Washington State code requirement (House Bill 1444) of the Energy Independence and Security Act (EISA) backstop provision. Originally adopted from the federal standard, the EISA backstop provision requires higher-efficiency technologies (45 lumens per watt or better). Washington State did adopt the EISA backstop provision.[35] The savings in the draft *2021 Power Plan* and RTF workbooks specify a 45 lumens per watt baseline (for Washington).

As a result, Cadmus developed a special case for residential lighting. After reviewing the Council and RTF workbooks, Cadmus concluded that the 45 lumens per watt baseline should be changed to an LED baseline for the CPA. Currently, there are no lighting technologies on the market that meet the 45 lumens per watt requirement other than CFLs and LEDs. Furthermore, major manufacturers have phased out production of CFLs. The market is rapidly adopting LEDs (according to the RBSA saturations and Council and RTF projections), which are becoming the *de facto* baseline. Considering that LEDs are the only viable technology that meets Washington code, Cadmus used LEDs as the baseline for all standard-income applications but assessed the potential for vulnerable population homes. This adjustment to the lighting loads is effectively accounted for in PSE's baseline forecast and in the CPA.

Secondly, the 2018 WSEC includes both residential and commercial new construction prescriptive and performance path requirement options. 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.

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

To ensure consistency with methodologies employed by the Council and to fulfill requirements of WAC 194-37-070, Cadmus relied on ECM workbooks developed by the RTF and the Council to estimate measure savings, costs, and interactions. Additionally, 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:** The business cases were utilized as the primary data source for measure characterization inputs, where possible. Using these business cases allows 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 to demonstrate compliance with Washington Energy Independence Act targets. Therefore, Cadmus sought to preserve these deemed savings to avoid possible inconsistencies among estimates of potential, targets, and reported savings.

[35] During the development of this study, the Biden-Harris Administration, through the U.S. Department of Energy, restated the EISA backstop with full enforcement until January 2023 (manufacture and import) and July 2023 (retail and distribution).

- **Use inputs specific to PSE's service territory:** Some Council and RTF 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.

Cadmus' approach for adapting PSE business cases, Council, and RTF workbooks varied by sector, as described in the following sections.

Residential and Commercial

Cadmus reviewed each residential Council workbook and extracted savings, costs, and measure lives for inclusion in this study. We largely derived the applicability factors (such as the current saturation of an ECM) from PSE's oversample of RBSA and CBSA, along with RBSA and CBSA public data associated to PSE heating and cooling climate zones. If Cadmus could not develop a PSE-specific applicability factor from the RBSA and CBSA, we used the Council's regional value.

In addition to extracting key measure characteristics, Cadmus identified each measure as an equipment replacement measure or a retrofit measure. There are two key distinctions between these two types of measures:

- We calculated savings for ***equipment replacement (lost opportunity) measures*** as the difference between measure consumption and baseline consumption. For instance, for the HPWH measure, Cadmus estimated the baseline consumption of an average market water heater and used the Council's deemed savings to calculate the consumption for a HPWH. This approach preserved the deemed savings in Council workbooks.
- We calculated savings for ***retrofit measures*** in percentage terms relative to the baseline end-use consumption but reflecting the Council's and RTF's deemed values. For instance, if the Council's deemed savings were 1,000 kWh per home for a given retrofit measure and Cadmus estimated the baseline consumption for the measure end use as 10,000 kWh, relative savings for the measure were 10%. Cadmus did not apply relative savings from the Council's workbooks to baseline end-use consumption because doing so would lead to per-unit estimates that differed from Council and RTF values.

Cadmus also accounted for interactive effects presented in Council and RTF workbooks. For instance, the Council estimated water heating, space heating, and space cooling savings for residential HPWHs—with space heating and cooling as the interactive savings. Because the installation of a HPWH represents a single installation, Cadmus employed a stock accounting model, which combined interactive and primary end-use effects into one savings estimate. Though Cadmus recognizes that this approach could lead to overstating or understating savings in an end use, in aggregate—across end uses—savings matched the Council's deemed values.

Cadmus generally followed the same approach with the commercial sector; however, because of the mixture of lighting measures considered in the Council's draft *2021 Power Plan*, Cadmus chose to model all commercial lighting measures as retrofits and none as equipment replacements. Savings and costs for these measures reflected this decision.

Industrial

Cadmus adapted measures from the Council's Industrial_Tool_2021P_v08 and IND_AllMeasures_2021P_V8 workbooks for inclusion in this study for several key industrial measure inputs:

- Measure savings (expressed as end-use percentage savings)
- Measure costs (expressed as dollars per kilowatt-hour saved)
- Measure lifetimes (expressed in years)
- Measure applicability (expressed in percentages)

Cadmus used all Council industry types and identified applicable end-uses using the Council's assumed distribution of end-use consumption in each industry.

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 an air conditioner] 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 85% of these units are electric (the fuel share).[36] Efficiency shares equal the current saturation of a specific type of equipment (of varying efficiency). Within an end use, these shares sum to 100%. For instance, the efficiency shares for the central air conditioner (CAC) end use may be 50% SEER 13, 25% SEER 15, and 25% SEER 16.

[36] Saturations are less than 1.0 when some homes do not have the end use.

Then 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 electricity
ESH_{ije}	=	The market share of efficiency level e 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, 1.0 for residential) for the electric equipment configuration ije

For each sector, Cadmus calculated 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.[37]

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 an end use and represented by a specific type of equipment (such as a CAC or heat pump). We derived the basis for the unit energy consumption values from savings in the PSE business cases, most recent RTF UES workbooks, 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 conducted other research.

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

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 kilowatt-hours 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.

To distribute the energy intensities to end-use intensities, Cadmus used assumptions specific to each building segment and each end use:

- **Lighting.** For lighting, Cadmus analyzed CBSA IV's lighting power density (lighting wattage per square foot) multiplied by the Council's interior lighting hours of use by building type. Once we had calculated the lighting end-use intensity, we subtracted this portion of load from the total CBSA electric energy intensities (to estimate non-lighting intensities).
- **Non-lighting.** To distribute the remaining non-lighting CBSA electric energy intensities into end-uses, Cadmus used *Commercial Building Energy Consumption Survey* (CBECS)[38] 2012 microdata to calculate percentages of end-use intensities across various end-use groups by building types as defined by the Council. Cadmus used the CBSA fuel shares and end-use saturations to adjust the distributions of CBECS end-use intensities to better represent PSE's commercial service territory. These finalized CBECS end-use intensities—adjusted with CBSA values where possible—were the basis for most of the end-use intensities in the commercial sector.
- **Computers and servers.** Cadmus developed energy intensities by building type for two end-uses—computers (desktops and laptops) and servers—using the CBECS number of units per square foot multiplied by unit consumption.
- **University.** The CBSA IV data lacked information on university building type, and the schools building type represented only K–12, as designated by the Council. Cadmus developed a more accurate electric energy intensity specific to universities by calculating a ratio of the CBECS's university and school K–12 building types. Cadmus then used the CBSA school K–12 lighting power density and applied the Council's university lighting hours of use. Cadmus determined that the result was reasonable by benchmarking the university lighting end-use intensity developed for PSE against the ratio of CBECS university and school K–12 lighting loads.
- **Retail.** Low CBSA respondent counts and trying to match varying definitions of Council's building types caused concern, especially for the large and extra-large retail building types, so Cadmus combined the retail building types for the CBSA electric energy intensities and lighting power density.

[38] U.S. Energy Information Administration. n.d. "2012 CBECS Survey Data." https://www.eia.gov/consumption/commercial/data/2012/

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, Cadmus characterized the heating and cooling 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 heat pump end-use consumptions on RTF estimates, adjusted using HVAC FMY to TMY ratios from Council-developed building simulations, as shown in Table 32.

Table 32. Residential Council Modeled HVAC FMY to TMY Ratios

Council Modeled Ratios	HVAC Ratio (FMY/TMY)
All Residential Heating – Heating Zone 1	80%
All Residential Cooling - Heating Zone 1	200%
All Residential Combined - Heating Zone 1	105%

The resulting heating and cooling end-use consumptions present the upper bound of the climate adjustment (final year estimate). Next, we calibrated the annual change in residential and commercial heating and cooling end-use consumptions 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). Cadmus also used the projected residential air conditioning saturations within PSE load forecast projections. We followed a similar process to determine the climate impacts for commercial heating and cooling end uses.

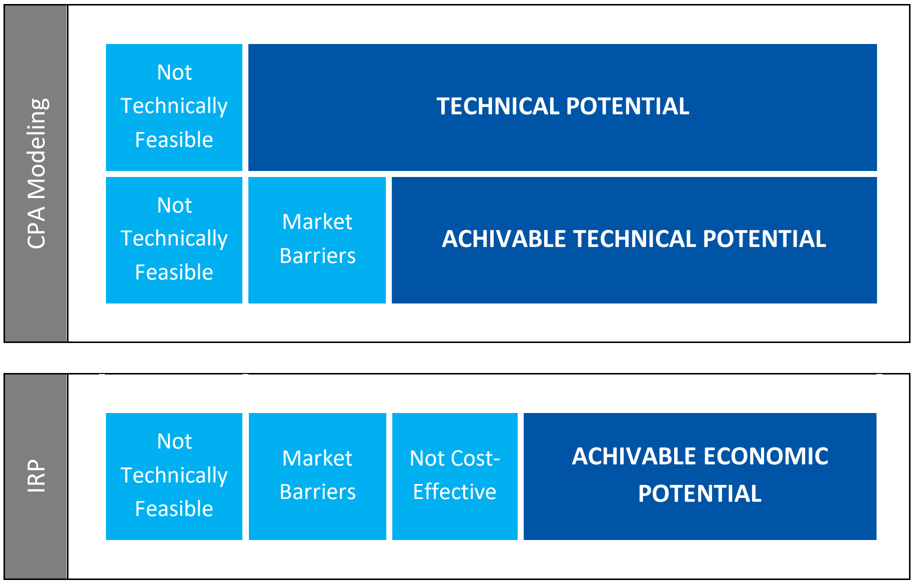
Conservation Potential Estimation

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 30:

- ***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 portion determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on cost 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 30. 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 and shell upgrades, economizer optimization, 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, appliances, and replace-on-burnout lighting fixtures.

Another important aspect in assessing technical potential is, wherever possible, to assume installations of the highest-efficiency equipment that are commercially available. For example, for this study Cadmus examined Tier 3 and Tier 4 heat pump water heaters in residential applications. To assess technical potential, we assumed that, as equipment fails or new homes are built, customers will install Tier 4 HPWHs wherever technically feasible, regardless of cost. Where applicable, we assumed that Tier 3 would be installed in homes ineligible for Tier 4 units. 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 heat pump in a home where insulation measures have already been installed can produce fewer 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 were 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:

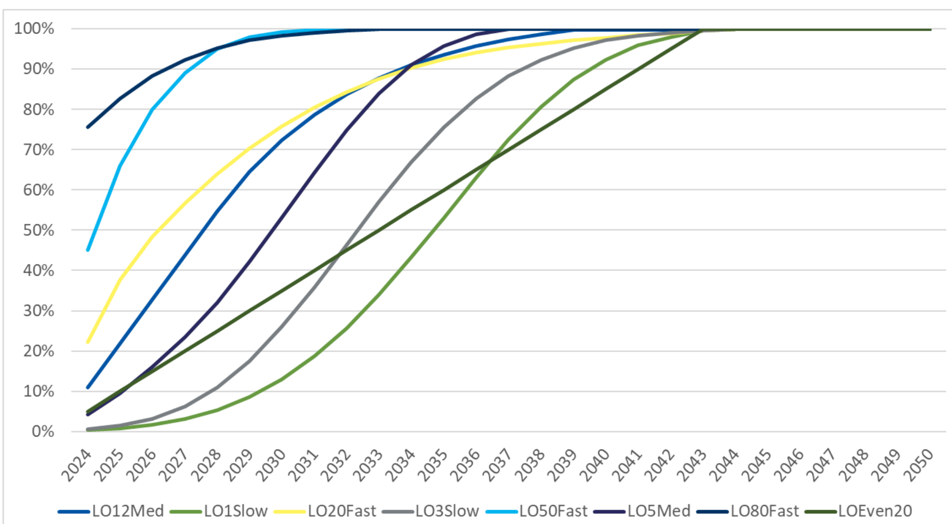
- **Maximum achievability factors** represent the maximum proportion of technical potential that can be acquired over the study horizon.
- **Ramp rates** are annual percentage values representing the proportion of cumulative 27-year technical potential that can be acquired in a given year (discretionary 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 only cover the 2024 to 2043 timeline. 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 31 illustrates the lost opportunity Council ramp rates.

Figure 31. Lost Opportunity Council 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 hourly forecasts of electric energy efficiency potential. To produce these hourly 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 and CHP potential into the levelized costs bundles shown in Table 33. The number and delineating values of the levelized cost bundles remain unchanged from the 2021 CPA.

Table 33. Electric Levelized Cost Bundles

Bundle	Electric Bundle ($/kWh)
1	($9,999.000) to $0.028
2	$0.028 to $0.055
3	$0.055 to $0.062
4	$0.062 to $0.070
5	$0.070 to $0.077
6	$0.077 to $0.085
7	$0.085 to $0.115
8	$0.115 to $0.130
9	$0.130 to $0.150
10	$0.150 to $0.175
11	$0.175 to $0.200
12	$0.200 to $0.225
13	$0.225 to $999.00

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

$$\text{Levelized Cost of Electricity (LCOE)} = \frac{\sum_{\mathrm{t}=0}^{\mathrm{n}} \frac{Expenses_{\mathrm{t}}}{(1+\mathrm{i})^{\mathrm{t}}}}{\sum_{\mathrm{t}=0}^{\mathrm{n}} \frac{E_t}{(1+\mathrm{i})^{\mathrm{t}}}}$$

where:

LCOE = The levelized cost of conserved energy for a measure

n = The lifetime of the analysis (27 years)

$Expenses_{\mathrm{t}}$ = All net expenses in year *t* for a measure using the costs and benefits outlined in Table 34

i = The discount rate

n = The lifetime of the analysis (27 years)

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 34.

Table 34. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost [a]
	Administrative Adder
Benefits	Present Value of NEIs [b]
	Present Value of T&D Deferrals
	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.

[b] Some NEIs are negative, and in those cases were treated as a cost within 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.[39]

  For example, Figure 32 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 32. 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.

39 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.

- ***Non-energy impacts.*** We treated these impacts as a reduction in levelized costs for measures that save resources, such as water or detergent, 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 showerhead reduces the levelized cost of that measure. The details of how we accounted for the NEIs are outlined in the *Energy Conservation Measure Characterization* section.
- ***The regional 10% conservation credit, capacity benefits during PSE's system peak, and T&D deferrals.*** Cadmus treated these factors similarly to how we treated reductions in the levelized cost for electric measures. The addition of this credit per the Northwest Power Act[40] 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 an electric central cooling system and a natural gas furnace. For the central cooling end use, Cadmus considered the energy savings that R-60 insulation produces for natural gas furnace systems, conditioned on the presence of electric central cooling, 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 on the electric supply curve is not impacted by considering secondary energy benefits.

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40 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*.[41]

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 TRC 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 the per-unit energy 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 as 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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[41] 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).

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 (TRC) 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 costs to program administrators) compared to the present value of benefits, including avoided energy supply and demand costs.

Appendix A. Detailed Demand Response Potential Results and Input Assumptions by Product Option

This section provides the detailed demand response achievable technical potential for each product option and their associated input assumptions. This section also provides additional context of each demand response product and it may operate within a utility program.

Residential Direct Load Control Water Heat

Water heating DLC programs directly control water heaters in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI), radio, consumer Wi-Fi connections to the internet, power line carriers, paging infrastructure, or through other web-based communications. Several other technologies, such as grid-enabled water heaters (GEWH) and water heater timers, exist for curtailing water heating energy usage during peak hours.

For this analysis, Cadmus assumed that participants in water heating DLC programs receive incentives at a yearly rate, independent of the number and duration of events called, as events could be called during any season depending on demand. Such incentives can be delivered through multiple applicable channels (such as bill credits or lump-sum check payments) and can include incentives to cover the costs of enabling a DLC device and/or a one-time sign-up bonus to boost enrollment. Fixed, annual, or monthly bill credits are common, simple, and easy to understand, and incentives for residential DLC programs also can be structured to pay per event or per enrolled kilowatt.

Product Options

All residential customers with electric storage water heaters are eligible to participate in the residential DLC water heat program. This analysis involves two product options for the residential DLC water heat program: load control switches and GEWHs. However, because the peak savings between ERWHs and HPWH differ, Cadmus split the eligible participants of these two product options between these two water heater types according to equipment saturations. This resulted in four product permutations for this simulated DLC water heat demand response program:

- ERWH – Load control switches
- ERWH – GEWH
- HPWH – Load control switches
- HPWH - GEWH

For the switch option, the utility installs the switch on customers' existing electric water heaters. The grid-enabled option is for customers who own a GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling a two-way connection to the utilities' grid infrastructure. One primary advantage of this built-in communication capability is the opportunity for greater participation in water heater DLC programs. These water heaters can also be controlled more often, potentially serving other utility grid needs.[42]

Washington State recently passed legislation that mandated for electric storage water heaters manufactured on or after January 1, 2021, to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent.[43] As a result, all new electric storage water heaters after 2021 will be GEWH, and will thus be eligible for the GEWH product option. This analysis incorporates the estimated impacts of this legislation by shifting program participants from the switch products to the GEWH products over time for each water heater type.

This analysis also includes a stock turnover consideration. Cadmus assumed that HPWHs will be cost-effective and will replace ERWHs over time as they reach the end of their equipment lives. The water heating potential results from this study reflect this dynamic.

For peak event hours in summer and winter, Cadmus assumed that water heaters cycle off for 50% of the event's duration. As most electric water heaters use tank storage systems, which allow customers to draw on stored hot water during event times, the water heater load shifts on and off every 20 or 30 minutes for an event's duration.

Input Assumptions

Table A-1 provides the cost and impact assumptions that Cadmus used to estimate potential and levelized costs for the residential DLC water heat program.

Table A-1. Residential Direct Load Control Water Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 full-time equivalent (FTE) staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	$13	$26 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which aligns with the switch water heater product assumption, and based on consultation with the Council's Bonneville Power Administration (BPA) demand response subject matter expert (SME).
Equipment Cost	$ per new participant	Switches: $165	$330 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$473; Portland General Electric (PGE) (2019) =$300; PacifiCorp (2019) =$315; BPA (2018) =$315, which uses PacifiCorp's potential study (Applied 2017) estimate; the Council's consultation with the BPA demand response SME =$315; Snohomish (2017) =$280; PSE (2019) =$315.
		GEWH: $25	$50 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and RTF GEWH assumptions: RTF =$50.

42 Bonneville Power Administration. November 9, 2018. *CTA-2045 Water Heater Demonstration Report.* https://neea.org/resources/cta-2045-water-heater-demonstration-project

43 State of Washington. Passed April 18, 2019. *Certification of Enrollment: Second Substitute House Bill 1444.* http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1444-S2.PL.pdf

Parameters	Units	Values	Notes
Marketing Cost	$ per participant	$15	$30 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$50; BPA (2018) =$25, which uses the Navigant (2012) marketing cost; the Council's consultation with the BPA demand response SME =$25; Snohomish (2017) =$25; PSE (2019) =$25.
Incentives (annual)	$ per new participant per year	$5	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC test is based on the Council's consultation with the BPA demand response SME. The Council's draft *2021 Power Plan* used an incentive of $15 per season for switch water heaters, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$21 per season; BPA (2018) =$24 per season, which uses the higher end of the $24 to $25 range from Applied Energy Group (2017); the Council's consultation with the BPA demand response SME =$16 per season; Snohomish (2017) =$8 per season; PSE (2019) =$24 per season. Cadmus made the incentive align with the GEWH products and be more reflective of the Council's benchmarked values.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the draft *2021 Power Plan* input assumptions.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5%, which uses the Snohomish (2017) =5% attrition; PSE (2019) =5%.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	Electric water heater saturations and ERWH/HPWH split based on updated residential consumer survey data and regionwide RBSA (2017) data. Grid-enabled growth rate based on the Council's draft *2021 Power Plan* demand response workbooks. HPWH saturation growth rate based on the Council's draft *2021 Power Plan* "Res-HPWH_v3" workbook.
Peak Load Impact	kW per participant (at meter)	ERWH Summer: 0.5 ERWH Winter: 0.75	ERWH Switch: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =0.4 for summer and 0.8 for winter; BPA (2018) =0.55 for summer and 0.75 for winter, which is from BPA end-use submetering studies. ERWH GEWH: The Council's draft *2021 Power Plan* used a peak load impact of 0.50 kW for both seasons. Cadmus found no clear evidence to discount grid-enabled per unit impacts relative to switch products. Therefore, we changed the peak load impact assumption to align with this product's switch counterpart.
Peak Load Impact	kW per participant (at meter)	HPWH Summer: 0.122 HPWH Winter: 0.244	HPWH Switch: The Council's draft *2021 Power Plan* used a peak load impact of 0.15 kW for summer and 0.20 kW for winter. Cadmus found no clear evidence to differ grid-enabled and switch per-unit impacts for water heat products. Therefore, we changed the peak load impact assumption to align with this product's grid-enabled counterpart. HPWH GEWH: The Council's draft *2021 Power Plan* used a peak load impact of 0.10 kW for summer and 0.20 kW for winter. These values are based on grid emergency watt reductions for the morning period from Table 3 in BPA (2018), which Cadmus used to update the peak load impact values.
Program Participation	% of eligible customers	Switches: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =16%; PacifiCorp (2019) =15%; BPA (2018) =25%, which uses the high end of the range from Snohomish (2017) =20%; PSE (2019) =25%.
Program Participation	% of eligible customers	GEWH: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PSE (2019) =48%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Switches: The Council's draft *2021 Power Plan* used an event participation of 94%, which relied on DRAC input and benchmarked values: BPA (2018) =95%, which assumed the same event participation as for space heating DLC from Navigant (2012); Snohomish (2017) =94%; PSE (2019) =95%. Cadmus made the event participation 95% to align with other DLC products. GEWH: The Council's draft *2021 Power Plan* used an event participation of 94%, which relied on DRAC input and benchmarked values: Snohomish (2017) =94%; PSE (2019) =95%. Cadmus made the event participation 95% to align with other DLC products.
Ramp Period	Number of years to reach maximum potential	Switches: 5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; Snohomish (2017) =5 years.
		GEWH: 10	Using the draft *2021 Power Plan* input assumptions. Consistent with other DLC products.
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-2 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-2. Winter Residential Direct Load Control Water Heat Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential DLC ERWH-Switch	10, 4-hour events	0 min	$24	0
Residential DLC ERWH-Grid-Enabled	10, 4-hour events	0 min	-$28	32
Residential DLC HPWH-Switch	10, 4-hour events	0 min	$203	0
Residential DLC HPWH-Grid-Enabled	10, 4-hour events	0 min	$91	58

Residential Direct Load Control HVAC

All residential customers with centralized electric heating are eligible for the winter HVAC DLC program, including customers with heat pumps and electric forced-air furnaces. Baseboard heaters remain ineligible because they are not centrally controlled and would require numerous control switches per customer. Ductless heat pumps are excluded for a similar reason, although they are sometimes successfully controlled by utilities through demand response programs. DLC programs have opt-out event participation once a customer elects to participate; for this analysis, Cadmus assumed that customers can opt out or override their participation in an event by readjusting their thermostat.

All residential customers with a CAC are eligible for the summer HVAC DLC program. This category includes customers with heat pumps and standard CACs. Packaged terminal air conditioners, ductless heat pumps, and window-mounted air conditioners remain ineligible because customers typically use them for zonal (rather than whole-home) applications, and they require numerous control switches per customer. In addition, portable air conditioning devices (such as fans, cooling towers, and plug load air conditioner appliances) provide a significant portion (perhaps more than 50%) of the air-conditioning load in the Northwest's residential sector. This analysis excludes such portable air conditioning devices.

Numerous cycling strategies currently exist for HVAC DLC programs, from conservative 25% cycling to aggressive 100% cycling. This study sets the cycling strategy at 50%, meaning that HVAC equipment targeted through these products cycle off for 50% of an event's duration (such as being on for 30 minutes then off for 30 minutes).

Cadmus assumed that participants in HVAC DLC programs are paid incentives at a fixed rate, independent of the number and duration of events called. We chose this incentive structure due to its simplicity: it provides customers with a higher level of certainty regarding their bill credit amounts than if the incentive were paid per event or per kilowatt, and if no events were called, as could happen in a year with particularly mild temperatures. These incentives can be delivered through several applicable channels (including bill credits or check incentives) and can include a one-time sign-up bonus to boost enrollment.

Product Options

For programs that target central electric space heating (such as heat pumps and electric forced-air furnaces) and space cooling (such as heat pumps and central air conditioners), load control switches or smart thermostats are connected to a digital internet gateway. Load control switches allow the utility to cycle electric heating equipment on and off during peak events while smart thermostats automatically set back temperature setpoints on heating or cooling systems. For this analysis, two product options are offered:

- BYOT (for customers with smart thermostats)
- Load control switches (for customers without smart thermostats)

The BYOT product is for residential customers who already have a Wi-Fi or smart thermostat installed. These types of thermostats enable the utility to communicate with the customer during peak events and automatically change the setpoint temperature on heating or cooling systems depending on the season. The HVAC DLC switch product controls the same end uses as BYOT but does so via switches that are installed directly onto the HVAC equipment, rather than through a smart thermostat.

This analysis incorporates two important equipment saturation growths:

- Increased cooling system growth saturation due to climate change
- Smart thermostat saturation growth over time shifting participants from being eligible for the HVAC DLC switch product to being eligible for the BYOT product

Cadmus assumed that residential DLC HVAC products will be available for four-hour duration events with up to 10 events per season.

Input Assumptions

Table A-3 lists the cost and impact assumptions that Cadmus used in estimating the potential and levelized costs for the residential DLC HVAC program.

Table A-3. Residential Direct Load Control HVAC Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	BYOT: $4	$8 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: the Council's consultation with the BPA demand response SME =$8 for heating and $7 for cooling; PSE (2019) =$7.5 for heating.
		Switches: $10	$20 annually, weighted by relative shares of heating/cooling and split by region. Using the Council's draft *2021 Power Plan* input assumptions, based on benchmarked values: Avista (2019) =$13 for cooling; PacifiCorp (2019) =$11 for each season.
Equipment Cost	$ per new participant	BYOT: $0	Residential BYOT assumes that customers already have a smart thermostat installed.
		Switches: $230 annual	$230 annually, weighted by electric forced air furnace/air-source heat pump split. Using the draft *2021 Power Plan* input assumptions, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons.
Marketing Cost	$ per new participant	$35	BYOT: $70 annually, split evenly by season. The Council's draft *2021 Power Plan* used a marketing cost of $50 for winter and $35 for summer, which was based on the presumption that recruitment of participants may be more difficult in the winter. However, the program participation rate is higher in the winter. Cadmus made the marketing cost $35 for each season. Switches: The Council's draft *2021 Power Plan* used a marketing cost of $50 for winter and $35 for summer, based the presumption that recruitment during the winter may be more difficult. However, program participation for this product is greater in the winter than in the summer. Cadmus updated the marketing cost for winter to $35 to align with the summer marketing cost.
Incentives (annual)	$ per participant per year	BYOT Summer: $7 BYOT Winter: $7	BYOT: $20 annually, 35% participant cost = $7. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$20; PacifiCorp (2019) =$20.

Parameters	Units	Values	Notes
		Switch Summer: $7 Switch Winter: $11	Switch: $30 for winter, 35% participant cost = $10.5 for winter. $20 for summer, 35% participant cost = $7 for summer. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. The winter incentive is using the Council's draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked BPA (2018) annual incentive. The annual incentive from the previous demand response potential assessment (DRPA) is based on the following: Applied (2017) space heating DLC =$20; Navigant (2012) space heating DLC =$32; Global (2011) space heating DLC =$50.The Council's draft *2021 Power Plan* used an incentive of $30 for summer. The benchmarked values include Avista (2019) =$20; PacifiCorp (2019) =$20; the Council's consultation with the BPA demand response SME =$15.
Incentives (one time)	$ per new participant	BYOT: $4	$10 per season, 35% participant cost = $3.5 per season. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. The Council's draft *2021 Power Plan* used a one-time incentive value of $20 per season. The benchmarked value of $25 from PGE (2020) is a one-time incentive regardless of season. Cadmus updated the incentive to be split by season.
		Switches: $0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of the water heater DLC product from the Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	HVAC system and smart thermostat saturations based on residential consumer survey analysis using PSE-specific weights. Smart thermostat growth based on the draft *2021 Power Plan* workbook "Res-Tstats-v2," incorporating growth in CAC saturation over time.
Peak Load Impact	kW per participant (at meter)	BYOT Summer: 0.94 BYOT Winter: 1.95	The Council's draft *2021 Power Plan* used a peak load impact of 1.27 kW for summer and 1.09 kW for winter, which was evaluated results from PGE programs. Other residential HVAC DLC products had a higher winter impact than summer impact, so Cadmus performed additional benchmarking for this product to verify or refute this discrepancy. Winter impacts are based on the PSE residential DLC pilot's evaluated impact values for morning and evening. Cadmus weighted heating type–specific impacts using residential consumer survey equipment saturations. This value aligns well with or is slightly higher than the values in Cadmus and the Council's benchmarked sources. Summer impacts are based on the PGE residential BYOT pilot's evaluated impact values.
		Switches Summer: 0.59 Switches Winter: 1.2	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts for winter west and summer west from the previous DRPA for BPA (2018). Using Applied (2017) Oregon for winter west peak load impacts, Applied (2017) = 1 – 1.78. Using the average of the following for summer west: Brattle (2016) =0.80; Applied (2017) Oregon =0.43; Applied (2017) Washington =0.53. Selected west impact values only from the draft *2021 Power Plan* to be specific to PSE.

Parameters	Units	Values	Notes
Program Participation	% of eligible customers	BYOT Summer: 25% BYOT Winter: 35%	The Council's draft *2021 Power Plan* used a summer program participation of 20%, which is based on the PGE (2020) benchmarked value. Other benchmarking values included Avista (2019) =25%; PacifiCorp (2019) =25%; BPA (2018) =25%. To better reflect these benchmarked values, Cadmus updated the summer program participation to 25%. The winter value is based on the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =16%; PacifiCorp (2019) =25%; BPA (2018) =25%; Snohomish (2017) =50%; PSE (2019) =20%.
		Switches Summer: 10% Switches Winter: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked winter program participation from BPA (2018). Using the high end of the 15% to 25% range in Global (2011). The summer program participation is reflective of the following benchmarked data from the Council's draft *2021 Power Plan*: BPA (2018) =25%, which uses the Global (2011) estimate; PGE (2019) =12%; PacifiCorp (2019) =5%; BPA (2018) =5%.
Event Participation	%	BYOT: 70%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =80% for heating and cooling, which is using the IPL (2014) 21% opt-out rate and rounding it to 20%; Snohomish (2017) =62% for heating; PSE (2019) =80% for heating.
		Switches: 95%	The Council used an event participation of 94% for winter and 95% for summer. The summer event participation rate is from the benchmarked BPA (2018) data. The benchmarked values in the previous DRPA for BPA (2018) for space heating, CAC DLC, and programmable communicating thermostat programs range from 0.64 to 0.96. Navigant (2012) had 0.94, matching participation for the Con Edison (2012) CAC program. The winter participation rate is reflective of the benchmarked data: Snohomish (2017) =94%; PSE (2019) =94%; BPA (2018) =95%, which was used to align with the other DLC products. Cadmus made the event participation 95% to align with other DLC products.
Ramp Period	Number of years to reach maximum potential	BYOT: 3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product.
		Switches: 5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; PGE (2019) =5 years; Snohomish (2017) =5 years.
Program Life	Years	BYOT: 7	BYOT: Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment. Residential thermostat EUL based on the RTF (2022) workbook.
		Switches: 10	Switches: Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Parameters	Units	Values	Notes
Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.			

Results

Table A-4 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-4. Winter Residential Direct Load Control HVAC Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential DLC Heat-Switch	10, 4-hour events	0 min	-$24	97
Residential DLC Heat-BYOT	10, 4-hour events	0 min	-$56	108

Residential Direct Load Control Electric Vehicle Supply Equipment

Residential EV charger demand response programs can be implemented to reduce EV charging in residential homes during peak hours. Networked Level 2 EV chargers allow customers to better manage their EV charging and offer PSE some ability to control and track EV charging patterns.

Product Description

EV owners can charge their EVs at home, though not all are expected to have an installed Level 2 charger. Cadmus assumed that most existing Level 2 chargers are not networked. Therefore, we focused on EV owners who currently charge at home but do not have a Level 2 charger installed. Through the residential EV DLC product option, PSE would pay for the incremental cost of installing a connected Level 2 charger. Through the residential EV DLC, PSE offers a financial incentive for residential EV owners to install a new networked Level 2 charger and pays an annual incentive in exchange for curtailing EV charging loads during peak events. Connected Level 2 chargers predominantly communicate via Wi-Fi or cellular service and can reduce 0% to 100% of output power in response to an event signal. Cadmus incorporated EV saturation growth into the potential modeling for this product based on forecasts provided by PSE. We assumed that events last up to four hours, with 10 events each season.

Input Assumptions

Table A-5 lists the cost and impact assumptions Cadmus used to estimate the potential and levelized costs for a residential EVSE program.

Table A-5. Residential Direct Load Control Electric Vehicle Supply Equipment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	$5	$10 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input. Benchmarked values included Avista (2019) =$11; PacifiCorp (2019) =$11.
Equipment Cost	$ per new participant	$140	$280 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input.
Marketing Cost	$ per new participant	$25	$50 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	$ per participant per year	$8	$22 per season, 35% participant cost = $7.70 per season. The 35% assumption used in the TRC is consistent with the residential DLC HVAC and residential BYOT products. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$24 per season; PacifiCorp (2019) =$20 per season.
Incentives (one time)	$ per new participant	$0	Using the draft *2021 Power Plan* input assumptions.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions. Consistent with other DLC products: BPA (2018) =5%; Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	AMI is 100% across all sectors by 2023 according to PSE (2022). Residential EV counts are estimated based on the EV sales forecast provided by PSE.
Peak Load Impact	kW per participant (at meter)	0.34	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =0.34; PacifiCorp (2019) =0.28. The Avista (2019) study is based off Avista's EVSE pilot program, where the measured value was 0.41 kW but only 82.5% of the participants were reached. Therefore, Cadmus used a lower peak load impact of 0.34 kW for this study. The PacifiCorp (2019) peak load impact was based off an EV pilot program for Xcel (2014) Energy.
Program Participation	% of eligible customers	20%	Using the draft *2021 Power Plan* input assumptions for single-family and manufactured homes, which relied on DRAC input and benchmarked values: PGE (2019) =20%; PacifiCorp (2019) =25%. The program participation in the PGE (2019) study was based on the demand response potential study conducted by The Brattle Group in 2016. For this study, Cadmus calibrated the program participation from the start year of 2023 to PGE's targets. Cadmus estimated the PacifiCorp (2019) program participation by scaling the time-of-use (TOU) participation by equipment saturations for EVs.
Event Participation	% (switch success rate)	95%	Using the draft *2021 Power Plan* input assumptions, consistent with other DLC products. This value aligns with the benchmarked values in the previous DRPA for BPA (2018). Space heating and CAC DLC and programmable communicating thermostat programs range from 0.64 to 0.96. Navigant (2012) had 0.94, matching participation for the Con Edison (2012) CAC program.

Parameters	Units	Values	Notes
Ramp Period	Number of years to reach maximum potential	5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-6 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-6. Winter Residential Direct Load Control Electric Vehicle Supply Equipment Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential EV DLC	10, 4-hour events	0 min	$105	42

Commercial Direct Load Control HVAC

Commercial DLC programs operate similarly to most residential DLC programs. In this commercial DLC HVAC program, the utility directly reduces the electric HVAC load of small and medium commercial buildings (in the office or retail segments) during event hours via load control switches or smart thermostats. For this analysis, Cadmus assumed that four-hour events will be dispatched, with up to 10 events per season.

Program participants receive incentives at a yearly rate (though all payments may occur in one season), independent of the number and duration of events called. These incentives can be delivered through several applicable channels (including bill credits and check incentives).

Product Options

Commercial customers in the small or medium office or retail segments with electric space heating and cooling systems are eligible for the commercial DLC HVAC program. This analysis involved three product options by eligible commercial segments and enabling equipment:

- Small office and retail - Switch
- Small office and retail - BYOT
- Medium office and retail - Switch

Input Assumptions

Table A-7 lists the cost and impact assumptions Cadmus used in estimating potential and levelized costs for the commercial DLC HVAC program.

Table A-7. Commercial Direct Load Control HVAC Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	Switches: $20	$40 annually. The Council's draft *2021 Power Plan* used an O&M cost of $18 for winter and $20 for summer. Cadmus found no clear evidence as to why winter would cost more than summer. Therefore, we updated the winter O&M cost to $20 per season.
		BYOT: $4	$8 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: the Council's consultation with the BPA demand response SME =$8 for heating and $7 for cooling; PSE (2019) =$7.5 for heating.
Equipment Cost	$ per new participant	Small Switch: $387 annual	$387 annually, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the draft *2021 Power Plan* input assumptions.
		Medium Switch $1,130 annual	$1,130 annually, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the draft *2021 Power Plan* input assumptions.
		BYOT: $0	Commercial BYOT assumes that customers already have a smart thermostat installed.
Marketing Cost	$ per new participant	Small Switch: $35	$69 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from BPA (2018). This value is the midpoint of the $63 to $75 range for small C&I from Applied (2017).
		Medium Switch: $43	$85 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$75 to $90; BPA (2018) =$83, which used the midpoint of the $75 to $90 range for medium C&I from Applied (2017); PSE (2019) =$83.
		BYOT: $38	$75 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75

Parameters	Units	Values	Notes
Incentives (annual)	$ per participant per year	Small Switch: $21	$76 annually, split evenly by season =$38 per season, 55% participant cost =$21 per season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =$38 per season, which is from Applied (2017); PacifiCorp (2019) =$38 per season.
		Medium Switch: $72	$130 per season, 55% participant cost = $71.5 per season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$128 per season; BPA (2018) =$128 per season, which is from Applied (2017); PSE (2019) =$128 for winter.
		BYOT: $22	$40 per season, 55% participant cost = $22 per season. Using the draft *2021 Power Plan* input assumptions: BPA (2018) =$38 per season; PacifiCorp (2019) =$38 per season.
Incentives (one time)	$ per new participant	Switches: $0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product.
		BYOT: $6	$20 annually, split evenly by season. 55% participant cost = $5.5 per season. The Council's draft *2021 Power Plan* used a one-time incentive value of $20 per season. The benchmarked value of $25 from PGE (2020) is a one-time incentive regardless of season. Cadmus updated the incentive to be split by season.
Attrition	% of existing participants per year	5%	Assuming similar to residential BYOT and commercial HVAC switch products. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of the water heater DLC product from the Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	HVAC system saturations based on the CBSA (NEEA 2020) analysis using PSE-specific weights. Thermostat saturations and growth based on the Council's draft "2021P Com-ConnectedThermostats_V2" workbook.
Peak Load Impact	kW per participant (at meter)	Small Switch Summer: 1.1 Small Switch Winter: 1.9	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The summer values are from Applied (2017), where east is using the midpoint values for Washington (1.3) and Idaho (1.2) and west is equal to the value for Oregon (1.1). Cadmus selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). Cadmus derived the winter values from the residential DLC space heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. Cadmus calculated the average small commercial HVAC capacity from CBSA (2014) data (Navigant 2015). We selected the west impact value to be specific to PSE.

Parameters	Units	Values	Notes
		Medium Switch Summer: 12.3 Medium Switch Winter: 9.2	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The summer values are from Applied (2017), where east is using the midpoint values for Washington (15.2) and Idaho (13.2) and west is equal to the value for Oregon (12.3). Cadmus selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). Cadmus derived the winter values from the residential DLC space heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. We calculated the average small commercial HVAC capacity from CBSA (2014) data (Navigant 2015), and selected the west impact value to be specific to PSE.
		BYOT Summer: 1.1 BYOT Winter: 1.9	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =1.1 kW for west and 1.25 kW for east. We selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =1.87 kW for west and 2.5 1 kW for east. We selected the west impact value to be specific to PSE.
Program Participation	% of eligible customers	Switches: 10%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from BPA (2018). This value was from Global (2011).
		BYOT Summer: 25% BYOT Winter: 35%	The draft *2021 Power Plan* aligned commercial thermostat program participation assumptions with residential thermostat program participation assumptions. The Council's draft *2021 Power Plan* used a summer program participation of 20%, which is based on the PGE (2020) benchmarked value. Other benchmarking values included Avista (2019) =25%; PacifiCorp (2019) =25%; BPA (2018) =25%. To better reflect these benchmarked values, Cadmus updated the summer program participation to 25%. The winter value is based on the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =16%; PacifiCorp (2019) =25%; BPA (2018) =25%; Snohomish (2017) =50%; PSE (2019) =20%.
Event Participation	% (switch success rate)	Switches: 95%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).
		BYOT: 70%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =80% for heating and cooling, which is using the IPL (2014) 21% opt-out rate and rounding it to 20%; Snohomish (2017) =62% for heating; PSE (2019) =80% for heating.
Ramp Period	Number of years to reach maximum potential	Switches: 5	Using the draft *2021 Power Plan* input assumptions.
		BYOT: 3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product.

Parameters	Units	Values	Notes
Program Life	Years	Switches: 10 BYOT: 5	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment. Commercial thermostat EUL based on RTF (2022b) workbook.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption TablesError! Reference source not found.*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-8 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-8. Winter Commercial Direct Load Control HVAC Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Small Commercial DLC Heat-Switch	10, 4-hour events	0 min	$0	3
Small Commercial DLC Heat-BYOT	10, 4-hour events	0 min	-$36	3
Medium Commercial DLC Heat-Switch	10, 4-hour events	0 min	-$33	18

Commercial and Industrial Curtailment

For the C&I curtailment product, PSE requests that large C&I customers curtail their loads at a predetermined level for a predetermined event duration. Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumed that the event duration lasts four hours, with up to 10 events called per season (for a total of 40 hours).

The incentive payments to participants can be tariff based or a supplemental payment contract (Cadmus considered payment contracts only):

- ***Tariff Based:*** Participants are assigned to a tariff with more favorable billing determinants in exchange for agreeing to have a portion of their load interrupted or operations curtailed in response to direction from the utility or grid operator.
- ***Payment Contract:*** Participants enter a separate contract with the utility or grid operator to curtail load upon request. Generally, the program administrator will specify the dispatch parameters and participants will commit to reducing a certain amount of load upon dispatch for one or more years.

Under a payment contract, customers receive payments to remain ready for curtailment, even if actual curtailment requests do not occur. Therefore, this product represents a firm resource.

Participating customers execute curtailment according to the curtailment agreement after the utility calls an event. The specifics of curtailment contracts vary: some allow customers to meet their pledged demand reductions by reducing load from any end use while others tie load reduction requirements to a specific end use or piece of equipment. Furthermore, these load reductions may be achieved through a utility-controlled DLC switch (known as curtailment with enablement) or through actions taken directly by the customer (known as curtailment without enablement). Historically, Northwest utilities have conducted commercial building, public facility, and industrial pilots that tested results both with and without enablement demand curtailment products. Both types of pilots have similar expected costs.

While there are multiple strategies and curtailment contract requirements that can be implemented to target large C&I loads, this study only includes payment contract curtailment products that can target all end-use loads. Though actual implementation methods may differ from the curtailment contracts modeled in this analysis, the potential captured by these products in this analysis can be considered representative of the potential that could be achieved through other implementation strategies.

Product Description

Cadmus assumed that eligible participants include customers with at least 150 kW of monthly average demand in all C&I segments, excluding small office, small retail, medium office, and medium retail. The percentage of load represented by end-use customers meeting this requirement varies across commercial segments.

Input Assumptions

Table A-9 lists the costs and impact assumptions Cadmus used to estimate the potential and levelized costs for the C&I curtailment program.

Table A-9. Commercial and Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per kW pledged per year	Industrial: $5	$10 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked O&M cost from BPA (2018), assuming the low-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate. The O&M cost was $5 per season, while the remaining $20 per season was for incentives.
		Commercial: $15	$30 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked O&M cost from BPA (2018), assuming the high-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate. The O&M cost was $15 per season, while the remaining $20 per season was for incentives.

Parameters	Units	Values	Notes
Equipment Cost	$ per new kW pledged	$5	$10 annually split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked equipment cost from BPA (2018).
Marketing Cost	$ per new kW pledged	$0	Using the draft *2021 Power Plan* input assumptions. Consistent with the previous DRPA for BPA (2018), assuming that the marketing cost is included in the O&M costs.
Incentives (Annual)	$ per kW pledged per year	$40/kW + $150/MWh	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked annual incentive from BPA (2018). Split evenly between seasons, only 55% and 75% of the incentive is included in TRC for commercial and industrial, respectively.
Incentives (One Time)	$ per new kW pledged	$0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions. Consistent with other demand response products.
Eligibility	% of segment/end-use load	Varies by segment	Using the draft *2021 Power Plan* input assumptions, which uses benchmarked load class eligibility and customer segmentation from PacifiCorp (2012) and the 2018 BPA DRPA.
Peak Load Impact	% of eligible segment/end-use load	25%	Using the draft *2021 Power Plan* input assumptions, which uses benchmarked load class eligibility and customer segmentation from PSE (2019) for commercial and from Avista (2019) =21%; BPA (2018) =52% for industrial.
Program Participation	% of eligible segment/end-use load	Industrial: 25%	The Council's draft *2021 Power Plan* used a program participation of 15%, which relied on DRAC input. This 25% assumption aligns with Cadmus' recent DRPA for BPA (Cadmus 2018). During this most recent BPA DRPA, after discussion with BPA staff, Cadmus updated the program participation to align with the assumption used in the previous DRPA, which showed that Northwest potential assessment results generally average 20% (Snohomish 2017; Applied 2017).
		Commercial: 15%	Conservative estimate in line with recommendations made by demand response DRAC utilities.
Event Participation	%	Industrial: 90%	Using the draft *2021 Power Plan* input assumptions.
		Commercial: 95%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impact from BPA (2018), where benchmarked event participation rates range from 52% (average rate from BPA 2012) to 95% (BPA and Energy Northwest 2016).
Ramp Period	Number of years to reach maximum potential	5	Using the draft *2021 Power Plan* input assumptions. Consistent with commercial demand curtailment, which is based off PacifiCorp (2019).
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Parameters	Units	Values	Notes
Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.			

Results

Table A-10 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-10. Winter Commercial and Industrial Curtailment Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Commercial Curtailment	10, 4-hour events	Day-ahead (up to 2 hours ahead)	-$28	16
Industrial Curtailment	10, 4-hour events	Day-ahead (up to 2 hours ahead)	-$37	5

Residential Critical Peak Pricing

Under a CPP program, customers receive a discount on their retail rates during noncritical peak periods in exchange for paying premium prices during critical peak events. The critical peak price is determined in advance, which gives customers some degree of certainty about participation costs.

The program follows the basic rate structure of a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, which is generally set to reflect the utility's avoided cost of supply during peak periods.

These programs typically use AMI data to monitor and calculate when a customer's consumption occurs. These programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive times. Because AMI is necessary for billing purposes, all residential customers with AMI are eligible.

CPP rates take effect for only a limited number of times during peak seasons. When emergency or high market prices are in effect, the utility can invoke a critical peak event. The utility notifies customers that rates have become much higher than normal and encourages them to shed or shift load. Typically, notification is via email or text a day prior to the CPP event and the day of the event. For this analysis, Cadmus assumed that 10 CPP events are called with a duration of four hours each, for a total of 40 event hours during each season.

Product Options

There are several product options for CPP offerings. Residential rate-driven demand response CPP is a more targeted time-of-day pricing product (compared to a typical TOU product) that has a larger price ratio of on-peak to off-peak hours. For example, a TOU program may have a 2:1 (on peak: off-peak) price ratio, while a CPP program may have a 6:1 ratio. Additionally, CPP typically affects significantly fewer hours during the year (known as the critical peak periods) than TOU rates and comes with a higher incentive. The end goal of all pricing products, including CPP, is to shift customer behavior. For example, customers may turn off lights more diligently or wait to do laundry until after peak pricing ends regardless of whether they are in a CPP or TOU program. These pricing products often target large pools of customers, many of whom may have not participated in a demand response program before. As a result, these products can serve as opportunities to recruit new participants for other demand response programs.

Input Assumptions

Table A-11 provides the cost and impact assumptions Cadmus used in estimating the potential and levelized costs for the residential CPP program.

Table A-11. Residential Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assumes that AMI is fully developed for pricing programs. Using the draft *2021 Power Plan* input assumptions. Consistent with the DRPA for BPA (2018).
Marketing Cost	$ per new participant	$25	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions. This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	Summer: 13% Winter: 7.5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked peak load impacts from Avista (2019) and PacifiCorp (2019). These seasonal differences are also evident in PGE Flex 2.0 and PGE Test Bed Peak Time Rate. These sources represent a wide range of Pacific Northwest utilities.
Program Participation	% of eligible segment load	15%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =15%; PSE (2019) =15%. The benchmarked values from the previous DRPA for BPA (2018) are from Cadmus (2013) for Washington =5%; Cadmus (2017) =10%; Applied (2017) =17%; Brattle (2016) =29% (opt-in) or 90% (opt-out).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked event participation from PSE (2019).
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-12 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-12. Winter Residential Critical Peak Pricing
Achievable Technical Potential and Levelized Cost by Product Option

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential CPP	10, 4-hour events	Day ahead	-$56	33

Commercial Critical Peak Pricing

The commercial CPP product is similar to the residential CPP program: participants are encouraged to reduce or shift their demand during peak periods to low demand time periods through price signals.

These programs use AMI to monitor and calculate when a customer's consumption occurs. Different electric rates are then applied to a customer's load depending on when electricity is used—rates are higher during peak times and lower during off-peak times (relative to a traditional constant electric retail rate). As a consequence, these programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive times. Because AMI data are necessary for billing purposes, all C&I customers with AMI are eligible.

Product Options

For this analysis, Cadmus only modeled a single product option within this category. This aligns with the granularity outlined by the Council's *2021 Power Plan*.

Input Assumptions

Table A-13 lists the cost and impact assumptions Cadmus used to estimate the potential and levelized costs for the commercial CPP program.

Table A-13. Commercial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$100	$200 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions. Annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	8%	This value is based on the Council's draft *2021 Power Plan* corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp (2019) potential study, which are industry estimates and are not regional: they are "based on experience with full-scale programs in the Northeastern U.S." Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, Cadmus aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program event participation from PSE (2019).
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-14 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-14. Winter Commercial Critical Peak Pricing Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Commercial CPP	10, 4-hour events	Day ahead	-$57	21

Industrial Critical Peak Pricing

The industrial CPP program is similar to the residential and commercial CPP programs but is meant for industrial customers.

Product Options

Cadmus only modeled a single product option within this category. This aligns with the granularity outlined by the Council's *2021 Power Plan*.

Input Assumptions

Table A-15 lists the cost and impact assumptions Cadmus used in estimating potential and levelized costs for the industrial CPP program.

Table A-15. Industrial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses the Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$100	$200 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions and annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).
Peak Load Impact	% of eligible segment load	8%	This value is based on the Council's draft *2021 Power Plan* corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp (2019) potential study, which used assumptions that are industry estimates and are not regional: they are "based on experience with full-scale programs in the Northeastern U.S." Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, Cadmus aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).

Parameters	Units	Values	Notes
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-16 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-16. Winter Industrial Critical Peak Pricing Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Industrial CPP	10, 4-hour events	Day ahead	-$34	2

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DEMAND FORECAST

APPENDIX F

PUGET SOUND ENERGY

Contents

1. **Introduction** 1
2. **Model Estimation** 1
   - 2.1. Customer Counts 2
   - 2.2. Use Per Customer 3
   - 2.3. Peak Electric Hour 3
3. **Base and Final Demand** 4
   - 3.1. Billed Sales Forecast 4
   - 3.2. Demand 5
   - 3.3. Peak Demand 6
   - 3.4. Hourly Demand Forecast 7
4. **Stochastic Demand Forecasts** 8
   - 4.1. Economic and Demographic Assumptions 8
   - 4.2. Temperature 9
   - 4.3. Electric Vehicles 9
   - 4.4. Model Uncertainty 9
5. **Climate Change Assumptions** 9
   - 5.1. Energy Forecast 10
   - 5.2. Peak Forecast 10
   - 5.3. Hourly Forecast 13

1. Introduction

We employed time series econometric methods to forecast monthly energy demand and peaks for Puget Sound Energy's (PSE) electric 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 sales), retail rates, economic and demographic drivers, normal weather, and short-term demand-side resource (DSR) forecasts to create a long-term projection of monthly demand and peaks. Puget Sound Energy's 2023 Electric Progress Report (2023 Electric Report) base demand forecast for energy reflects short-term DSR via codes and standards impacts, and committed energy efficiency program targets through 2023. The 2023 Electric Report base demand net of DSR also reflects the optimal DSR we chose in the 2023 report analysis. Figure F.1 depicts the demand forecast development process.

Figure F.1: Demand Forecast Development Process

Model Estimation: Billed Sales, Customer Counts, Peak

- Billed sales volume, Effective Retail Rates
- Customer counts
- PSE System Load
- Economic and demographic observations
- Temperature observations at Sea-Tac Airport station

Forecast Models: Billed Sales, Customer Count, Peak

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

Base Demand Forecasts, before additional DSR: Demand and Peak

- Major projects, EV forecast, System Additions and Departures
- Losses
- Billing cycles schedules
- 2022–2023 Short term demand side resources, code changes, and solar

Final Demand Forecast, after additional DSR: Demand and Peak

- 2023 IRP Demand Side Resources 2024–2050, including solar
- Effects of 70 percent more efficient building codes

2. Model Estimation

To capture incremental customer growth, temperature sensitivities, and economic sensitivities, we forecasted billed sales by estimating UPC and customer count models. Models are disaggregated into the following major classes and sub-classes, or sectors as determined by tariff rate schedule, to best estimate the underlying determinants of each class.

- Commercial — high-voltage interruptible, large, small/medium, lighting
- Industrial — high-voltage interruptible, large, small/medium
- Resale
- Residential
- Streetlights

Each class's historical sample period ranged from January 2003 to December 2021. Some class estimation periods start later than January 2003 or end earlier than December 2021 to isolate the impacts of the COVID-19 pandemic without impacting the long-term forecast levels and sensitivities.

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

2.1. Customer Counts

We estimated monthly customer counts by class and sub-class. These models use explanatory variables such as population, unemployment rate, and total and sector-specific employment. We estimated larger customer classes via first differences, with economic and demographic variables implemented in a lagged or polynomial distributed lag form to allow delayed variable impacts. Some smaller customer classes are held constant. The team also utilized autoregressive moving average (ARMA) (p,q) error structures, subject to model fit.

The equation we used to estimate customer counts is[1]:

$$CC_{C,t} = \boldsymbol{\beta_C}[\propto_C \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{ED}_{C,t}] + u_{C,t},$$

The details for the estimating equation components are:

$\boldsymbol{CC_{C,t}}$	=	Count of customers in Class/sub-class C and month t
C	=	Class/sub-class, as determined by tariff rate
t	=	Estimation time
$\boldsymbol{\beta_C}$	=	Vector of CC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
$\propto_{\boldsymbol{C}}$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{D_{M,t}}$	=	Vector of month/date-specific indicator variables
$\boldsymbol{T_{C,t}}$	=	Trend variable (not included in most classes)
$\boldsymbol{ED_{C,t}}$	=	Vector of economic and/or demographic variables
$\boldsymbol{u_{C,t}}$	=	ARMA error term

[1] The term vector or boldface type denotes one or more variables in the matrix.

2.2. Use Per Customer

We estimated monthly use per customer (UPC) at the class and sub-class levels using multiple explanatory variables. Major drivers include heating degree days (HDD), cooling degree days (CDDs), seasonal effects, retail rates, and average billing cycle length. We also used economic and demographic variables such as income and employment levels. Finally, an ARMA(p,q) is added depending on the equation. The equation we used to estimate UPC is[2]:

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

The details for the estimating equation components are:

$\boldsymbol{UPC_{C,t}}$	=	Billed Sales ($\boldsymbol{Billed\ Sales_{C,t}}$) divided by Customer Count ($\boldsymbol{CC_{C,t}}$)
$\boldsymbol{D_{C,t}}$	=	Average of billed cycle days for billing month t in class C
$\boldsymbol{\beta_C}$	=	Vector of regression coefficients
$\propto_C$	=	Indicator variable for class constant (if applicable)
$\boldsymbol{DD_{C,t}}$	=	Vector of weather variables ($\mathbf{HDD}_{C,Base,t=45}, \cdots, \mathbf{HDD}_{C,Base,t=65}$ $\mathbf{CDD}_{C,Base,t=55}, \dots, \mathbf{CDD}_{C,Base,t=70}$). These are calculated values that drive monthly heating and cooling demand.
$\mathbf{HDD}_{C,Base,t}$	=	$\sum_{d=1}^{Cycle_t} \lvert \max(0, \text{Base Temp} - \text{Daily Avg Temp}_d)\rvert$
$\mathbf{CDD}_{C,Base,t}$	=	$\sum_{d=1}^{Cycle_t} \lvert \max(0, \text{Daily Avg Temp}_d - \text{Base Temp})\rvert * \text{BillingCycleWeight}_{C,d,t}$
$\boldsymbol{D_{M,t}}$	=	Vector of month/date-specific indicator variables
$\boldsymbol{T_{C,t}}$	=	Trend variable (not included in most classes)
$\boldsymbol{RR_{C,t}}$	=	The effective retail rate. The rate is smoothed, deflated by a Consumer Price Index, interacted with macroeconomic variables, and further transformed.
$\boldsymbol{ED_{C,t}}$	=	Vector of economic and/or demographic variables
$\boldsymbol{u_{C,t}}$	=	ARMA error term

2.3. Peak Electric Hour

The electric peak demand model relates observed monthly peak system demand to monthly weather-normalized demand. The model also controls for other factors, such as observed hourly temperature, holidays, the day of the week, and the time of day.

[2] The term vector or boldface type denotes one or more variables in the matrix.

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 equation 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. In the long-term forecast, growth in monthly weather-normalized demand will drive growth in forecasted peak demand, given the relationships established by the estimated regression coefficients.

The equation we used to estimate electric peak hourly demand is:

$$\boldsymbol{max}\left(\boldsymbol{Hour}_{1,t} \ldots \boldsymbol{Hour}_{H_t,t}\right) =$$

$$\boldsymbol{\beta}\left[\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{M,t} \quad \Delta Temperature_{N,t}\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{S,t}\boldsymbol{D}_{PeakType,t} \quad \boldsymbol{D}_{DoW,t} \quad D_{LtHr,t} \quad D_{Hol,t} \quad T_{Hot,t}\right] + \varepsilon_t$$

$\boldsymbol{Hour}_{J,t}$	=	Hourly PSE system demand (MWs) for hour j=1 to H_(t,)
$\boldsymbol{H}_t$	=	Total number of hours in the month at time t
$\boldsymbol{\beta}$	=	Vector of electric peak hour regression coefficients
$\boldsymbol{Demand}_{N,t}$	=	Normalized total demand in a month at time t
$\boldsymbol{\Delta Temperature}_{N}$	=	Deviation of actual peak hour temperature from the hourly normal minimum peak temperature
$\boldsymbol{D}_{M,t}$	=	Vector of monthly date indicator variables
$\boldsymbol{D}_{S,t}$	=	Vector of seasonal date indicator variables
$\boldsymbol{D}_{PeakType,t}$	=	Vector of heating or cooling peak indicators
$\boldsymbol{D}_{DoW,t}$	=	Vector of Monday, Friday, and Mid-Week indicators
$\boldsymbol{D}_{LtHr,t}$	=	Indicator variable for evening winter peak
$\boldsymbol{D}_{Hol,t}$	=	Indicator variable for holiday effects
$\boldsymbol{T}_{Hot,t}$	=	Trend to account for summer air conditioning saturation
$\boldsymbol{\varepsilon}_t$	=	Error term

3. Base and Final Demand

The customer count, UPC, and peak models we described comprise the foundation of the base demand forecasts. We forecasted customer count, UPC, and peaks using model coefficient estimates and forecasted variable inputs as we described in Chapter Six: Demand Forecast. We then added various externally sourced forecasts to get the final demand forecasts. The following sections summarize the results of the component forecast models (customer counts and UPC by class) and detail how we formed the demand forecasts from their component parts.

3.1. Billed Sales Forecast

We formed the class total billed sales forecasts $\widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t}$)by multiplying forecasted UPC and customers ($Block\ Sales_{C,t}$, then adjusting for known future discrete additions and subtractions ("$Block\ Sales_{C,t}$").

We incorporated significant additional sales changes as additions or departures to the sales forecast as we did not reflect them in historical trends in the estimation sample period. Examples include emerging electric vehicle (EV) demand or other infrastructure projects. Finally, for the base demand forecast, we reduced the forecast of billed sales by short-term codes and standards, programmatic energy efficiency targets, and customer-owned solar ($DSR_{C,t}$) by class, using established targets in 2022–2023 and forecasts of codes and standards and customer-owned solar estimates for 2022 and 2023 from the 2021 IRP.

The total billed sales forecast equation by class and service is:

$$Billed\ Sales_{C,t} = \widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t} + Block\ Sales_{C,t} + EV_{C,t} - DSR_{C,t}$$

The details for the estimating equation components are:

t	=	Forecast time horizon
$\widehat{UPC}_{C,t}$	=	Forecast use per customer
$D_{C,t}$	=	Average of scheduled billed cycle days in class C
$\widehat{CC}_{C,t}$	=	Forecast count of customers
$DSR_{C,t}$	=	Base Forecast: codes and standards, programmatic energy efficiency targets, and customer-owned solar for 2022 and 2023
$EV_{C,t}$	=	Incremental EV sales
$Block\ Sales_{C,t}$	=	Expected entering or existing sales not captured as part of the customer count or UPC forecast

We calculated total billed sales in a month as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{C,t}$$

3.2. Demand

We formed total system demand by aggregating individual class sales, distributing forecasted monthly billed sales into calendar sales, then adjusting for electricity losses from transmission and distribution.

The electric demand forecast ($\widehat{Demand}_{N,t}$) is the 2023 report base electric demand forecast.

The final demand forecast net of DSR will include the optimal conservation bundle calculated in the 2023 report.

3.3. Peak Demand

We forecasted electric peak hourly demand with internal and external peak demand assumptions. We employ the estimated model coefficients, normal design temperatures, and forecasted normal total system energy demand ($\widehat{Demand}_t$) less forecasted EV energy demand and short-term demand-side resources ($EV_t + DSR$) to create a peak forecast before EVs and DSR. We then adjusted this forecast with short-term forecasted peak demand-side resources ($DSR_{Peak,t}$), and forecasted EV peak demand at hour ending 18 (EV_t), to forecast total peak demand.

We removed EV and short-term DSR forecast projections from forecast normal total system energy demand in the peak hour forecast for an important reason: Energy demand DSR and EV projected MWH are distinct from peak demand DSR and EV MW and do not necessarily have the same daily demand shape as current demand on PSE's system. Thus, using the same relationships between energy demand and peak demand as of 2021 is not a valid treatment for DSR and EVs in the forecast period: Different conservation measures may have larger or small impacts on peak when compared with energy.

Thus, the peak model reflects the peak DSR assumption from short-term codes and standards and energy efficiency programs and activities, as opposed to simple downstream calculations from demand reduction. We employed this same methodology to best capture EV peak demand. We deducted EV energy demand from the base demand forecast used for peak demand forecasting, then added as a separate MW impact calculated from EV demand load shapes provided by the energy consulting firm, Guidehouse. These calculations yield system hourly peak demand in the evening each month based on normal design temperatures.

$$Peak\ Demand_t = F\left(\widehat{Demand}_{t,}, \Delta Temperature_{N,Design,t}\right) + EV_{t,HE=18} - DSR_{Peak,t}$$

$\boldsymbol{Peak\ Demand_t}$	=	Forecasted maximum system demand for month t
t	=	Forecast time horizon
$\boldsymbol{\widehat{Demand}_t}$	=	Forecast of delivered demand for month t
$\boldsymbol{\Delta Temperature_{Normal,Design,}}$	=	Deviation of peak hour/day design temperature from the monthly normal peak temperature
$\boldsymbol{EV_t}$	=	Electric Vehicle Demand at peak
$\boldsymbol{DSR_{Peak,t}}$	=	Ramped/shaped peak DSR from programmatic energy efficiency targets and short-term codes and standards effects; IRP Optimal DSR

For the electric peak forecast, we based the normal design peak hour temperature on the median (1 in 2 or 50th percentile) of seasonal minimum temperatures. The data we used to determine seasonal temperatures to reflect climate change in our forecast is a mix of historical data and future forecasted hourly temperatures, as provided by the Northwest Power and Conservation Council (NWPCC).

We netted the effects of the 2022 and 2023 conservation programs, estimated codes and standards update impacts, and customer-owned solar from the peak demand forecast to account for DSR activities already underway to reach the 2023 report's base peak demand forecast. This approach allows us to choose optimal future resources to meet peak demand. Once we determined the optimal DSR in this report, we adjusted the peak demand forecast for the peak contribution of future demand-side resources.

➔ Results of this analysis are in Chapter Six: Demand Forecast.

3.4. Hourly Demand Forecast

The AURORA portfolio analysis utilizes monthly energy and peak demand forecasts and an hourly forecast of PSE's demand. The AURORA demand forecast starts with hourly profiles. We then calibrated and shaped it to the forecasted monthly and peak demand forecasts we described. The hourly (8,760 hours + 10 days) profile starts with day one of the hourly shape as a Monday, day two as a Tuesday, and so on, with the AURORA model adjusting the first day to line up January 1 with the correct day of the week. We estimated the hourly demand shape with regression models relating observed temperatures and calendar effects to historical hourly demand data. We controlled for pandemic effects in the estimation period and suppressed them in the forecast period. We estimated demand for each hour, day of the week type (weekday, weekend/holiday), and daily average temperature type (heating, mild, cooling), yielding 24x2x3 sets of regression coefficients.

The statistical hourly regression equation summarizes the estimated demand relationships:

$$Demand_{h,d,s,t} =$$

$$\boldsymbol{\zeta_h}\left[Demand_{h-1,d,t} \quad \boldsymbol{D_{M,t}} \quad D_{Hol,d,t} \quad D_{Covid,d,t} \quad \boldsymbol{D_{DoW,d,t}} \quad \boldsymbol{T_{h,d,t}}\right] + u_{i,d,t}$$

$$\boldsymbol{T_{h,d,t}} =$$

$$\left[max(55 - T_{h,d,t}, 0) \quad max(T_{h,d,t} - 55,0) \quad max(55 - T_{h,d,t}, 0)^2 \quad D_{h=1}\, max(40 - DAvg_{t-1}, 0) \quad D_{h=1}\, max(DAvg_{t-1} - 70,0)\right]$$

$\boldsymbol{Demand_{h,d,t}}$	=	PSE hourly demand
h	=	Hour of day {1–24}
d	=	Day grouping {Weekday, Weekend/Holiday}
t	=	Date
s	=	Daily temperature grouping (heating, cooling, mild)
$\boldsymbol{\zeta_h}$	=	Vector of regression coefficients
$\boldsymbol{T_{h,d,t}}$	=	Hourly temperature at SeaTac Weather Station (KSEA)
$\boldsymbol{DAvg_{t-1}}$	=	Previous daily average temperature
$\boldsymbol{D_{M,t}}$	=	Vector of monthly date indicator variables

We forecasted an annual hourly demand profile with a future calendar of months, weekends, weekdays, and holidays and an annual 8,760-hour profile of typical normal temperatures sourced from the climate change temperature datasets described here and in Chapter Six: Demand Forecast. After we forecasted the standard demand shape, we augmented it with projected demand growth due to customer growth and increased air conditioning saturation and an hourly profile of forecasted EV demand, sourced from the consulting firm, Guidehouse.

We created the final hourly shape in the AURORA software by fully calibrating and shaping the forecasted hourly demand to forecasted monthly delivered demand ($\widehat{Demand}_{N,t}$) and monthly peak demand, as forecasted for the 2023 report base demand forecast. We used AURORA's option for Pivot High Hours, which scaled the hourly demand forecasts based on ranking and preserved low demand hours to calibrate and shape the final output.

4. Stochastic Demand Forecasts

Demand forecasts are inherently uncertain. Acknowledging this uncertainty, we considered distributions of stochastic demand forecasts in this report's models. We created two sets of stochastic demand forecasts to model these uncertainties for analyses. These energy and peak demand forecast sets are:

- The 310 electric stochastic monthly energy and peak demand forecasts that we developed for AURORA modeling
- The 90 stochastic monthly energy demand, seasonal peak demand, and hourly demand forecasts for years 2028–2029 and 2033–2034 that we used to model resource adequacy.

➔ Please see Chapter Seven: Resource Adequacy for E3's description of the methodology used to develop resource adequacy load forecasts used in the RA analysis.

Variability in the energy and peak demand forecast originates from underlying customer growth and usage uncertainty. We forecasted customer growth and usage with varying underlying driver assumptions, principally economic and demographic indicators, temperatures, EV growth, and regression model estimate uncertainty to create a distribution of potential energy and peak demand forecasts.

4.1. Economic and Demographic Assumptions

The econometric demand forecast equations depend on specific economic and demographic variables; these may 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), personal income, 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 simulations of demand. 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[3] by providing the standard errors for the quarterly growth of key U.S. macroeconomic inputs into PSE's economic and demographic models.

We based these standard errors 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 outliers from the 1,000 economic and demographic draws.

4.2. Temperature

We modeled uncertainty in the heating and cooling load levels by considering varying future years' degree days and temperatures. We randomly sourced 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.

4.3. Electric Vehicles

The team sourced high and low scenarios of EV energy and peak demand from Guidehouse in addition to the base EV demand forecast. We provide these forecasts in Chapter Six: Demand Forecast. Although the 310 stochastic demand forecasts evaluated in the AURORA modeling process include a proportional number of these high/low EV scenarios, the demand forecasts we developed for resource adequacy modeling did not.

4.4. Model Uncertainty

The stochastic demand forecasts introduce model uncertainty by adjusting customer growth and usage by normal random errors, consistent with the statistical properties of each class and sub-class regression model. These model adjustments are consistent with Monte-Carlo's methods of assessing regression models' uncertainty.

5. Climate Change Assumptions

Puget Sound Energy's demand forecasting models employ various thresholds of HDDs and CDDs, consistent with industry practices. Monthly degree days help estimate the service area's heating- and cooling-sensitive demand. Most PSE's customer classes are weather sensitive and require a degree day assumption. A degree day measures the heating or cooling severity, as 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 degree day sensitivities, which we then forecasted forward with a monthly "normal" degree day assumption. To reflect climate change in the 2023 Electric Report, we employed historically observed temperatures and forecasted temperatures derived from climate change models provided by the NWPCC. Please see Chapter Six: Demand Forecast for details of the climate change models

[3] EViews is a popular econometric forecasting and simulation tool.

and results we incorporated. The following section discusses our methodology to create normal degree days from these various temperature sources.

5.1. Energy Forecast

We define monthly normal degree days as a rolling weighted average of the 15 years before and the 15 years after the forecast year, including the forecast year for the 2023 report. The years after historical actuals are three climate change models provided by the NWPCC. The new definition results in warmer winters, thereby decreasing total heating demand, and warmer summers, increasing cooling 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 $\boldsymbol{HDD}_{M,Base,t}$ and Cooling Degree Days $\boldsymbol{CDD}_{M,Base,t}$ for a scenario (M), Base temperature, and observation time (t) as:

$$\boldsymbol{HDD}_{M,Base,t} = \sum_{d=1}^{Days_t} max\left(0, Base\ Temp_t - Daily\ Avg\ Temp_{d,M}\right)$$

$$\boldsymbol{CDD}_{M,Base,t} = \sum_{d=1}^{Days_t} max\left(0, Daily\ Avg\ Temp_{d,M} - Base\ Temp_t\right)$$

To calculate normal heating or cooling degree days, we calculated historical actual degree days and weighted averages of the future degree day model for a time period t using the following data set:

$$\boldsymbol{DD}_{Base,t} = \begin{cases} \boldsymbol{DD}_{Actuals,Base,t}\ for\ t < Jan\ 2020 \\ \boldsymbol{\frac{1}{3}}\left(\boldsymbol{DD}_{CanESM2,Base,t} + \boldsymbol{DD}_{CCSM4,Base,t} + \boldsymbol{DD}_{CNRM,Base,t}\right) for\ t > Dec\ 2019 \end{cases}$$

To calculate normal degree days, we calculated the average monthly degree days for the 15 years prior and 15 years forward from the given year in the forecast period, using actual temperature data through 2020 and forecasted climate projections after 2020.

$$\boldsymbol{DDN}_T = \boldsymbol{\frac{1}{30}} \sum_{t=T-15}^{T+14} \boldsymbol{HDD}_{Base,t}\ , T = Jan\ 2024 - Dec\ 2050$$

5.2. Peak Forecast

Previous IRPs assumed an electric normal hourly peak temperature of 23 degrees, based on the 1-in-2 seasonal minimum temperatures during peak hours, hour ending (HE) 8 am–8 pm), for 30 years of history 1988–2017. To calculate the new peak temperature, we replicated and expanded the methodology used to calculate the previous peak temperature to incorporate multiple sets of climate model temperature projections and calculate peak temperatures under additional peak-specific conditions (evening-only specific peak).

5.2.1. Calculate Maximum and Minimum Temperatures in Season

For each model (M: CanESM2, CCSM4, CNRM), Year, Peak Period (All Hours: HE8–HE20 and Evening: HE17–HE19), and Season (Winter: Nov, Dec, Jan, Feb and Summer: June-September), calculate the minimum and maximum temperatures.

$$Min\ Temp_{Y,M,P=All} = \begin{cases} min\left(\boldsymbol{min(D_{H=8}\ T}_{Y,Actual}), \ldots, \boldsymbol{min(D_{H=20}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{min(D_{H=8}\ T}_{Y,Ml}), \ldots, \boldsymbol{min(D_{H=20}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

$$Min\ Temp_{Y,M,P=Evening} = \begin{cases} min\left(\boldsymbol{min(D_{H=17}\ T}_{Y,Actual}), \boldsymbol{min(D_{H=18}\ T}_{Y,Actual}), \boldsymbol{min(D_{H=19}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{min(D_{H=17}\ T}_{Y,Ml}), \boldsymbol{min(D_{H=18}\ T}_{Y,M}), \boldsymbol{min(D_{H=19}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

$$Max\ Temp_{Y,M,P=Evening} = \begin{cases} max\left(\boldsymbol{max(D_{H=17}\ T}_{Y,Actual}), \boldsymbol{max(D_{H=18}\ T}_{Y,Actual}), \boldsymbol{max(D_{H=19}\ T}_{Y,Actual})\right)\ Y < Aug\ 2021 \\ max\left(\boldsymbol{max(D_{H=17}\ T}_{Y,Ml}), \boldsymbol{max(D_{H=18}\ T}_{Y,M}), \boldsymbol{max(D_{H=19}\ T}_{Y,M})\right)\ Y > Aug\ 2021 \end{cases}$$

We extended the range of observed actuals for peak temperatures past calendar year-end into summer 2021 to reflect observations occurring during June 2021's Heat Dome event. We calculated additional peak temperature restrictions to reflect the time of day in which peak load typically occurs. The minimum daily temperature occurs almost exclusively during HE8 or HE9; thus, minimum temperatures calculated over all peak hours effectively represent morning peak conditions. We calculated the additional evening peak period to capture the expected peak temperature during evening peak load hours — the most common for December and summer peaks. The peak temperatures with these additional restrictions inform the evening peak demand forecast.

For each peak temperature type and period, the result will be four series (Actuals, CanESM2, CCSM4, CNRM) for each season, with observations of seasonal minimum and maximum for each year.

5.2.2. Create Samples of Minimum and Maximum Temperatures by Climate Period

Here we use the term climate period to refer to the 30-year rolling window of 15 years backward- and 15 years forward-looking data for projections. For example, in the forecast year 2024, the relevant climate period to create the sample of possible temperature outcomes is 2009 to 2038. The first forecast year that uses only climate change model projections is winter 2036.

For each peak temperature type (minimum or maximum), forecast year (T), and peak period (P), the sample population is used to determine a 1-in-2 temperature range below.

We define the sample set for each climate model by the 30 maximum and minimum temperatures by year and peak period:

$$\boldsymbol{Max\ Temp}_{T,M,P} = \{Max\ Temp_{Y=T-15,M,P}, \dots, Max\ Temp_{Y=T+14,M,P}\}$$

$$\boldsymbol{Min\ Temp}_{T,M,P} = \{Min\ Temp_{Y=T-15,M,P}, \dots, Min\ Temp_{Y=T+14,M,P}\}$$

The collection of sample sets defined, which span historical observations and climate models, forecast year, and peak period, defined the set we used for the distributions of peak temperature outcomes:

$$\boldsymbol{Max\ Temp}_{T,P} = \{\boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,Actual,P}, \boldsymbol{Max\ Temp}_{T,CANESM2,P},,, \boldsymbol{Max\ Temp}_{T,CCSM4,P}, \boldsymbol{Max\ Temp}_{T,CNRM,P}\}$$

$$\boldsymbol{Min\ Temp}_{T,P} = \{\boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,Actual,P}, \boldsymbol{Min\ Temp}_{T,CANESM2,P},,, \boldsymbol{Min\ Temp}_{T,CCSM4,P}, \boldsymbol{Min\ Temp}_{T,CNRM,P}\}$$

We repeated the actual observed temperature set to equally weight a year of historical observations with a year of the three future climate models because we did not aggregate the future climate models before we added them to the sample population. They have no averaging, nor did we take the minimum or maximum within individual climate model samples. This approach is the most straightforward way to not bias temperature observations towards the climate models and away from actual historical observations for appropriate climate periods. The sets $\mathbf{Max\ Temp}_{\mathrm{T,Actual}}$ and $\mathbf{Min\ Temp}_{\mathrm{T,P}}$ gradually shrink as the forecast year increases and is empty for T>2036.

5.2.3. Calculate 50th Percentile by Study Year

$$P\{Min\ Peak\ Temp_{T,P} < \boldsymbol{Min\ Temp}_{T,P}\} = 0.5$$

$$P\{Max\ Peak\ Temp_{T,P} < \boldsymbol{Max\ Temp}_{T,P}\} = 0.5$$

The resulting $Peak\ Temp_{T,P}$ for a given forecast year T (2024–2045), peak period P (all hours, evening hours), and type (minimum, maximum) is the expected temperature for which there is a 50 percent likelihood the actual peak seasonal minimum or maximum temperature will be higher or lower during the given peak period (all hours or just evening), based on the sample sets defined in the process above.

➔ Please see Chapter Six: Demand Forecast for a discussion of why climate change models are employed and why we must model an evening-specific peak event.

5.3. Hourly Forecast

We created the hourly temperature profiles by ranking days (24-hour temperature shapes) within a month by daily average temperature and then averaging the 24-hour temperature profile across relevant models. Depending on the year desired, the hourly average temperatures are an equal weighting of the 30-year rolling window of historical observations and the three climate change models. Once we created a set of typical monthly 24-hour profiles, we reordered days to typically observed monthly temperature patterns, with typical seasonal peak times (summer and winter) containing heating and cooling events consistent with the 1-in-2 peak temperature assumptions described Chapter Six: Demand Forecast.

5.3.1. Rank Monthly Temperature Observation by Daily Average Temperature

For each climate model and historical observation, rank days by daily average temperature within a month (M) and year (T), where:

$$\bar{t}_{T,M,(i)} = \sum_{h=1}^{24} Temp_{h,T,M}\ , i = 1 \ldots 28/30/31$$

Let (i) denote the order statistics of the daily temperature for the month:

$$\bar{\boldsymbol{t}}_{T,M} = \{\bar{t}_{T,M,(1)}, \ldots, \bar{t}_{T,M,(31)}\}$$

5.3.2. Average 24-hour Profiles by Daily Rank Across Appropriate Climate Period

As we discussed, the climate period for a forecast year is a 30-year rolling window of years, weighted appropriately to not bias against the historical period for appropriate years. For a given forecast year, in a month, the temperature profile (a 24-hour vector) for the ith ranked day is defined as:

$$
\begin{aligned}
&\boldsymbol{t}_{T,(i)} \\
&= \frac{1}{2} * \frac{1}{30} \\
&* \left(\left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CANESM2,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CANESM2,R=i} \right] \right. \\
&+ \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CCSM4,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CCSM4,R=i} \right] \\
&+ \left. \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,CNRM-CM5MACA,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,CNRM-CM5MACA,R=i} \right] \right) \\
&+ \frac{1}{2} \left[\sum_{C=T-15}^{T+14} Temp_{H=1,C,Actual,R=i} \quad \cdots \quad \sum_{C=T-15}^{T+14} Temp_{H=24,C,Actual,R=i} \right]
\end{aligned}
$$

5.3.3. Reorder the Daily Profile by Typical Daily Ranking

To reflect the typical progression of temperature patterns over a month, we reordered daily temperature profiles by a historical ranking of the coldest and warmest days in the month.

For a given year and month forecast year T, when n is the coldest day and 1 is the warmest day, and each $\boldsymbol{t}_{T,(i)}$ is a vector of 24 hours, an example of a typically ordered profile may be:

$$
\boldsymbol{t}_T = \begin{bmatrix} \boldsymbol{t}_{T,(2)} \\ \boldsymbol{t}_{T,(4)} \\ \cdots \\ \boldsymbol{t}_{T,(n-2)} \\ \boldsymbol{t}_{T,(n-1)} \\ \boldsymbol{t}_{T,(n)} \\ \cdots \\ \boldsymbol{t}_{T,(10)} \\ \boldsymbol{t}_{T,(14)} \\ \boldsymbol{t}_{T,(15)} \end{bmatrix}
$$

Because we expect the peak demand modeled to occur on a weekday and non-holiday, we adjusted the rankings by calendar year, so the most extreme days occur on the nearest non-holiday and mid-weekday to the warmest or coldest typical ranked day in a month.

ELECTRIC PRICE FORECAST

APPENDIX G

Contents

1. **Introduction** 1
2. **2021 Integrated Resource Plan** 3
3. **Modeling Power Prices** 3
   - 3.1. Model Framework Updates 3
4. **Electric Price Forecast Results** 10
5. **Electric Price Stochastic Analysis** 13
   - 5.1. Stochastic Natural Gas Price Inputs 13
   - 5.2. Stochastic Regional Demand 14
   - 5.3. Stochastic Hydroelectric Inputs 15
   - 5.4. Stochastic Wind Inputs 16
   - 5.5. Stochastic Climate Commitment Act Prices 16
   - 5.6. Stochastic Electric Price Forecast Results 17

1. Introduction

This appendix summarizes the electric price forecast assumptions and results Puget Sound Energy (PSE) used as a basis for the company's 2023 Electric Progress Report (2023 Electric Report).

We developed this electric price forecast as part of our 2023 Electric Report. In this context, electric price is not the rate charged to customers but PSE's price to purchase or sell one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. Electric price is essential to our analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio.

We performed two Western Electricity Coordinating Council (WECC)-wide modeling runs using AURORA software, an hourly chronological price forecasting model based on market fundamentals, to create wholesale electric price assumptions.

- The first AURORA model run identifies the capacity expansion needed to meet regional loads. AURORA looks at loads, peak demand, and a planning margin and then identifies the lowest cost resource(s) to ensure all the modeled zones are balanced.
- The second AURORA model run produces hourly power prices. A complete simulation across the entire WECC region produces electric prices for all 34 zones shown in Figure G.1. The lines and arrows in the diagram indicate transmission links between zones and their transmission capacity noted in megawatts.

Figure G.1 illustrates the AURORA System Diagram, and Figure G.2 shows PSE's process to create wholesale market electric prices using AURORA, as described.

The AURORA model produces electric price forecasts for each zone included in the model's topology. We then calculate the Mid-Columbia Hub (Mid-C) electric prices in post-processing as the demand-weighted average of the zones which compose the Pacific Northwest. The Pacific Northwest zones are Avista, Bonneville Power Administration (BPA), Chelan County Public Utility District (PUD), Douglas County PUD, Grant County PUD, PacifCorp West, Portland General Electric, Puget Sound Energy, Seattle City Light, and Tacoma Power.

Figure G.2: AURORA System Diagram

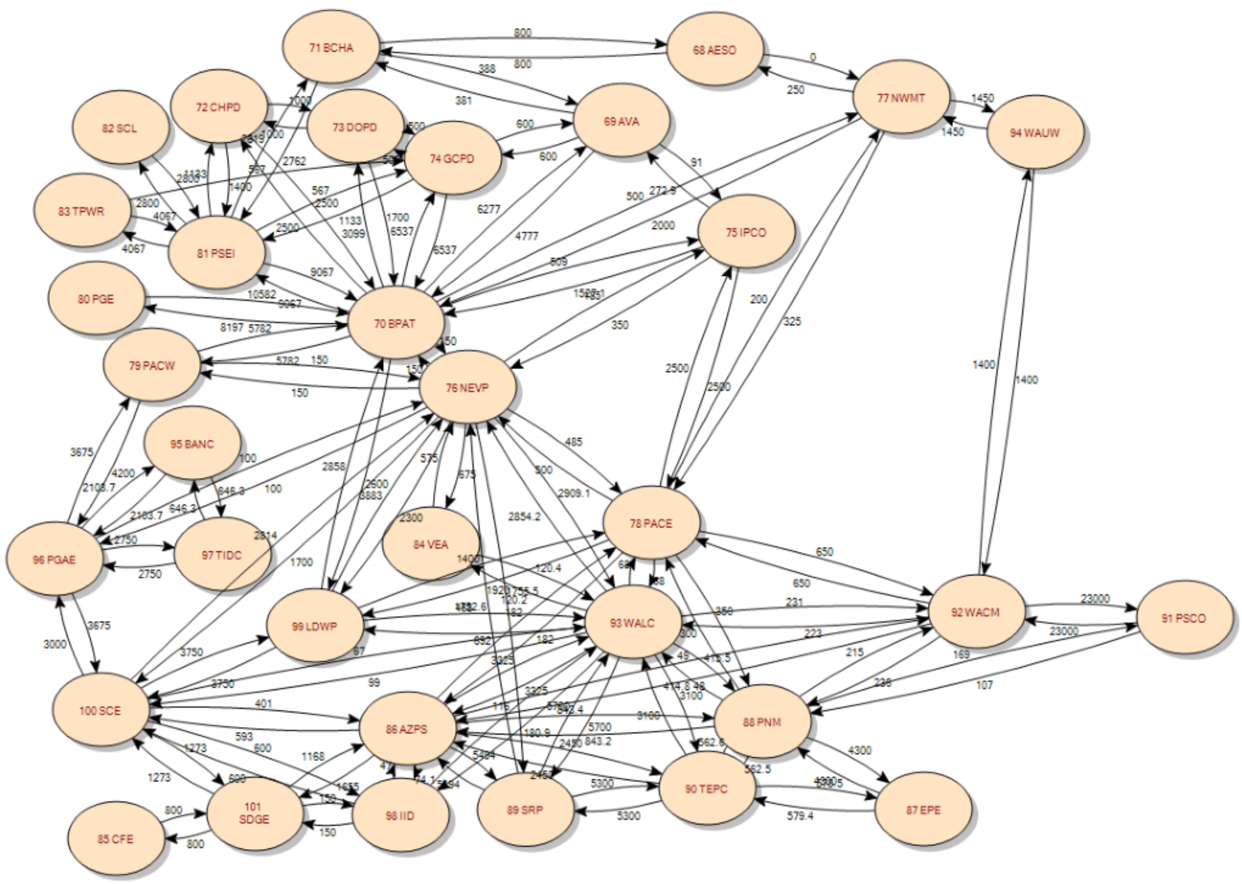
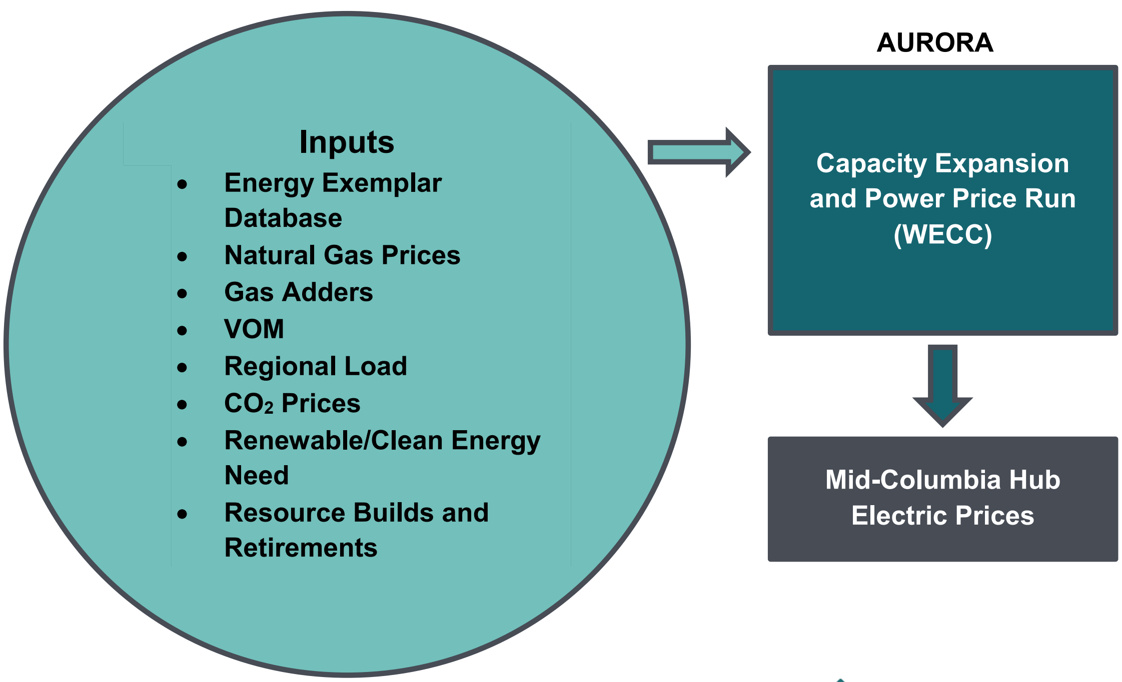


Figure G.1: PSE IRP Modeling Process for AURORA Wholesale Electric Price Forecast



2. 2021 Integrated Resource Plan

Puget Sound Energy filed the 2021 Integrated Resource Plan (IRP) in April 2021. We used inputs and assumptions from the Energy Exemplar 2018 database for AURORA price forecast modeling for the 2021 IRP. We then incorporated updates such as regional demand, natural gas prices, resource assumptions, renewable portfolio standard (RPS) needs, and resource retirements and builds. The 20-year levelized nominal power price in the Mid-C scenario for the 2021 IRP was $23.37/MWh. Details of the inputs and assumptions for the AURORA database are available for review in the 2021 IRP[1].

3. Modeling Power Prices

The electric price forecast for the 2023 Electric Report retains the fundamentals-based approach of forecasting wholesale electric prices while incorporating significant changes to some methodologies and input assumptions from the 2021 IRP process. Methodology changes include:

- Expand renewable portfolio and clean energy standards to include non-binding clean energy policies set by municipalities and utilities
- Include Washington State carbon pricing to reflect the impact of the Climate Commitment Act (CCA)
- Incorporate the impacts of climate change on demand and hydroelectric assumptions

This report documents all methodology and input assumption changes from the 2021 IRP.

3.1. Model Framework Updates

The electric price model for PSE's 2023 Electric Report includes two significant changes to the modeling framework from the 2021 IRP, updated AURORA software, and the WECC database updates.

3.1.1. AURORA Version 14.1

We updated the AURORA software from version 13.4, which we used for the 2021 IRP, to version 14.1 for the 2023 report. AURORA version 14.1 includes several changes that make it easier to use and allow greater modeling flexibility. AURORA enhancements include:

- New scripting functions
- Updates to the storage logic and limits on charging and generating in the same hour when a storage method has a minimum generation constraint

[1] PSE | 2021 IRP

3.1.2. Energy Exemplar WECC Zonal Database version 1.0.1

We updated the AURORA input database from the WECC 2018 database to the WECC 2020 database for the 2023 Electric Report. As a result of these changes, the WECC 2020 database:

- Introduces battery energy storage systems as a new resource option
- Limits the addition of new natural gas-fired power plants to years before 2030 across the WECC
- Modifies the structure of fuel price adders for increased flexibility
- Moves to a default 34-zone system topology that models each balancing authority in the WECC as a unique zone, a change from the 16-zone system topology previously used
- Updates generic resource costs
- Updates transmission assumptions

These changes result in a materially different starting point for the 2023 Electric Report and provide differing pathways for determining the solution in the long-term capacity expansion simulation from previous electric price models. We gained a more granular system topology by moving from a 16-zone to a 34-zone system that better represents the transmission constraints between balancing authorities across the WECC. Limitations on natural gas builds and adding storage as a new resource option provide more cost-effective decarbonization pathways to meet growing clean energy policy targets.

We made the following changes and updates to the WECC database:

- Adjusted clean energy policies
- Added climate change impacts
  - Updated the regional demand forecast based on climate change impacts
  - Updated the hydroelectric forecast based on climate change impacts
- Added Climate Commitment Act (CCA) impacts
- Updated natural gas prices

3.1.3. Clean Energy Policies

Clean energy policies are shaping the resource generation landscape of the WECC. For this electric price forecast, clean energy policies include a range of different targets, such as:

- Municipal clean energy goals and mandates
- Renewable portfolio standards
- Statewide clean energy goals
- Utility-set clean energy targets

These new targets depart from previous IRPs where we only modeled legislatively binding state policies (i.e., renewable portfolio standards). We include these other clean energy targets in PSE's 2023 Electric Report to reflect their impact on planning and implementing energy in the WECC. Our 2023 Electric Report includes clean energy policies aligned with the work performed by the Northwest Power and Conservation Council's (NPCC) 2021 Power Plan.

Modeling Clean Energy Policies

Puget Sound Energy's 2023 Electric Report features two modeling changes to reflect better the clean energy policies across the WECC.

In previous IRP cycles, we modeled clean energy targets by state consistent with the methodology in the Northwest Power and Conservation Council's (NPCC) Seventh Power Plan. This approach meant we had to add qualifying clean resources to the specific state which set the clean energy target. For example, an operator would have to construct a unit of Washington wind power in-state to fulfill a portion of the Washington renewable energy target.

This requirement is an unrealistic assumption because it limits utilities from sourcing energy from regions with better wind or solar resources than their home state. The NPCC realized this shortcoming and updated its methodology in the 2021 Power Plan to allow utilities to source clean resources beyond their state's boundaries. We adopted similar methods for the electric price forecast in this report. The new methodology set a WECC-wide clean energy target composed of all the clean energy targets for regional states. We then adjusted the NPCC methodology and carved out a small subset for the states of Washington and Oregon to ensure we met state policies more precisely.

In previous IRP cycles, PSE set clean energy targets only for new resources. This method subtracted contributions from existing resource generation from the total clean energy target, and only new resources counted toward meeting the clean energy target. This methodology required extensive accounting of clean energy contributions from existing resources outside the AURORA model, which may have understated the contribution of the existing clean energy resources.

In the 2023 Electric Report, we included existing and new resources in the modeled total clean energy target. We tagged both existing and new resources to contribute to the target. This approach allowed more precise accounting and better representation of all resources using AURORA's dispatch logic.

Both changes are consistent with methodologies used by NPCC in their electric price forecast AURORA model. We calculated clean energy targets using regulations, goals, and policies described in the NPCC 2021 Power Plan supplemental material[2]. We updated the NPCC clean policy targets for recent Oregon and Montana regulatory developments. Oregon adopted a 100 percent clean energy target by 2040 for investor-owned utilities, and Montana repealed its 15 percent renewable portfolio standard.

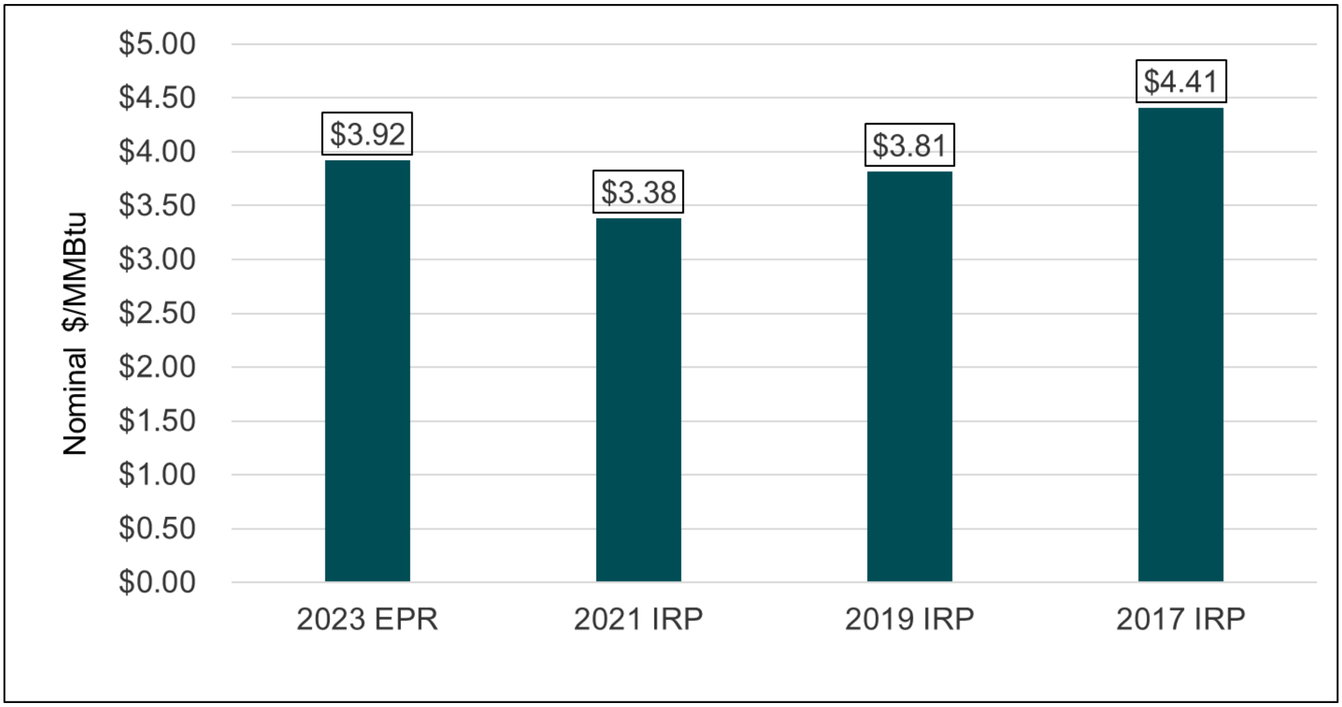
3.1.4. Gas Prices

Puget Sound Energy updated the long-term gas prices in this report to the most recent Wood Mackenzie forecasts and current forward market prices. We used the spring 2022 Wood Mackenzie Forecast, published in May 2022. The

[2] 2021 Power Plan Supporting Material Site Map (nwcouncil.org)

forecast shows an increase in long-term gas prices compared to the estimates used in the 2021 IRP, shown in Figure G.3.

Figure G.3: Levelized Natural Gas Price for the Sumas Gas Hub for Recent IRP



3.1.5. Climate Change

For the first time, PSE's 2023 Electric Report includes the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC), Part II[3], and selected three scenarios that represented a range of possible climate outcomes. PSE adopted these same three climate change scenarios:

- CanESM2_RCP85_BCSD_VIC_P1; coded as A
- CCSM4_RCP85_BCSD_VIP_P1; coded as C
- CNRM-CM5_RCP85_MACA_VIC_P3; coded as G

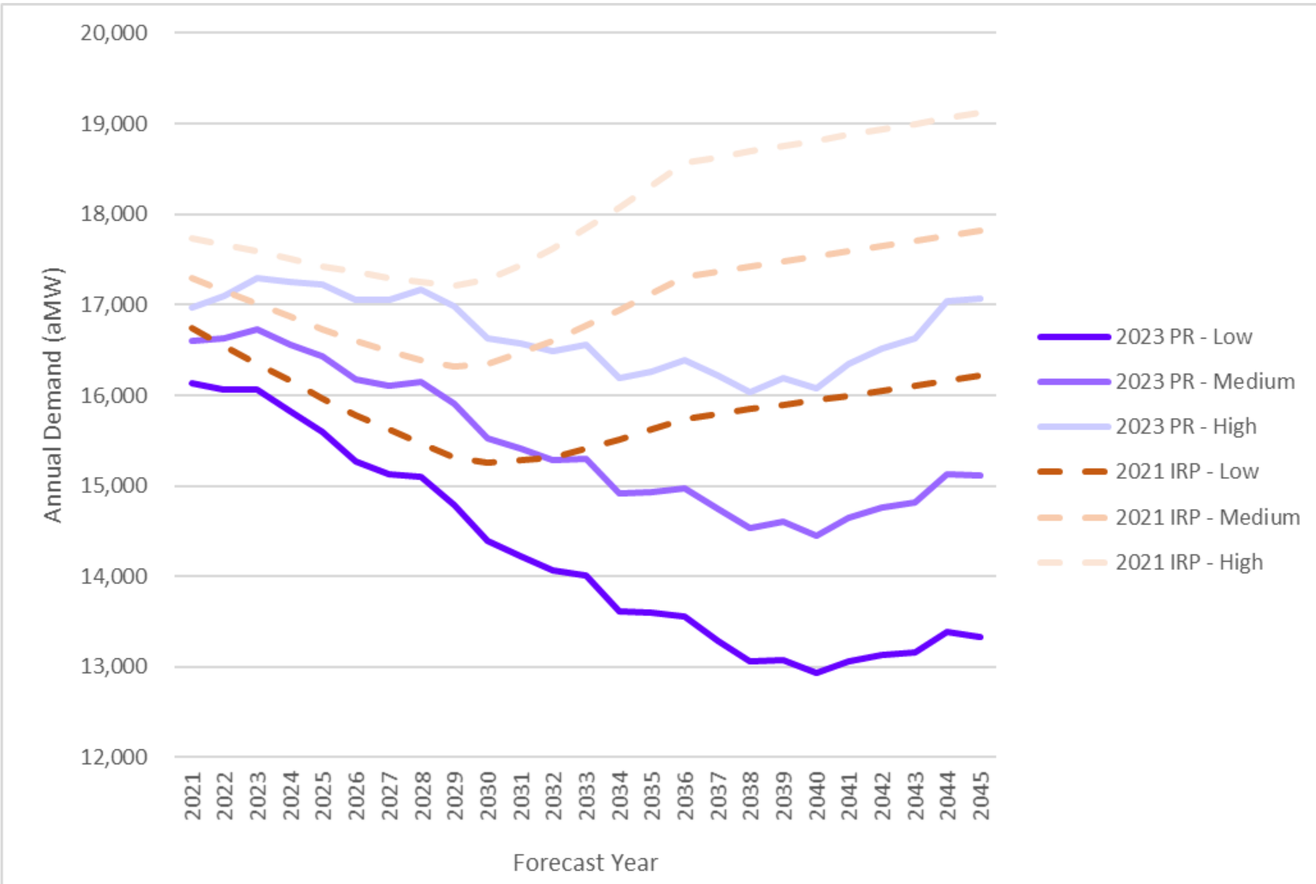
The three climate change scenarios we adopted uniquely impact the Pacific Northwest (PNW) load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the base electric price forecast averaged the effects of each climate change scenario to develop a single climate change case, which retains trends present in all three climate change scenarios.

3 Climate and hydrology datasets for RMJOC long-term planning studies: Second edition (RMJOC-II) - Technical Reports - USACE Digital Library (oclc.org)

Regional Demand Forecast

For the electric price modeling, PSE used the regional demand from the NPCC 2021 Power Plan. Figure G.4 reflects the PNW regional demand forecast change from the 2021 IRP to the 2023 Electric Report. The demand forecast includes energy efficiency in all cases.

Figure G.4: Annual Average Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



Climate Change Regional Demand Forecast

We incorporated the climate change regional demand forecast created by the NPCC for the 2021 Power Plan in the electric price forecast for this report. The regional demand forecast is presented seasonally in Figure G.5, with each forecast year as a separate line; darker lines represent years earlier in the planning horizon and lighter lines later in the planning horizon. We provided selected data from the 2021 IRP regional demand forecast for reference.

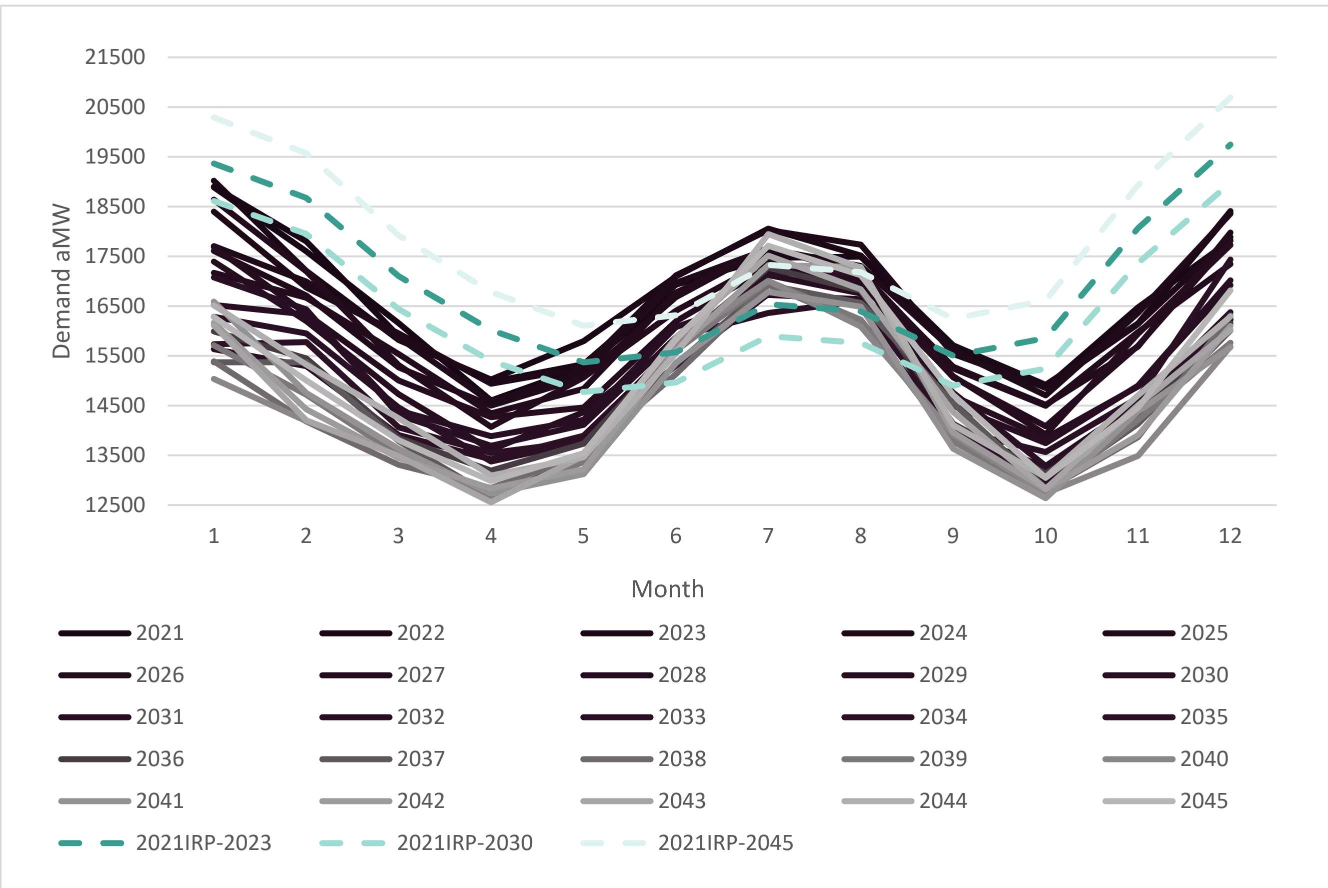
The climate change regional demand forecast shows warming winters and summers, which translates to lower demand in the winter than we modeled in the 2021 IRP and increased demand in the summer.

Climate Change Hydroelectric Forecast

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[4] regional resource adequacy model using streamflow data representative of the climate change scenarios.

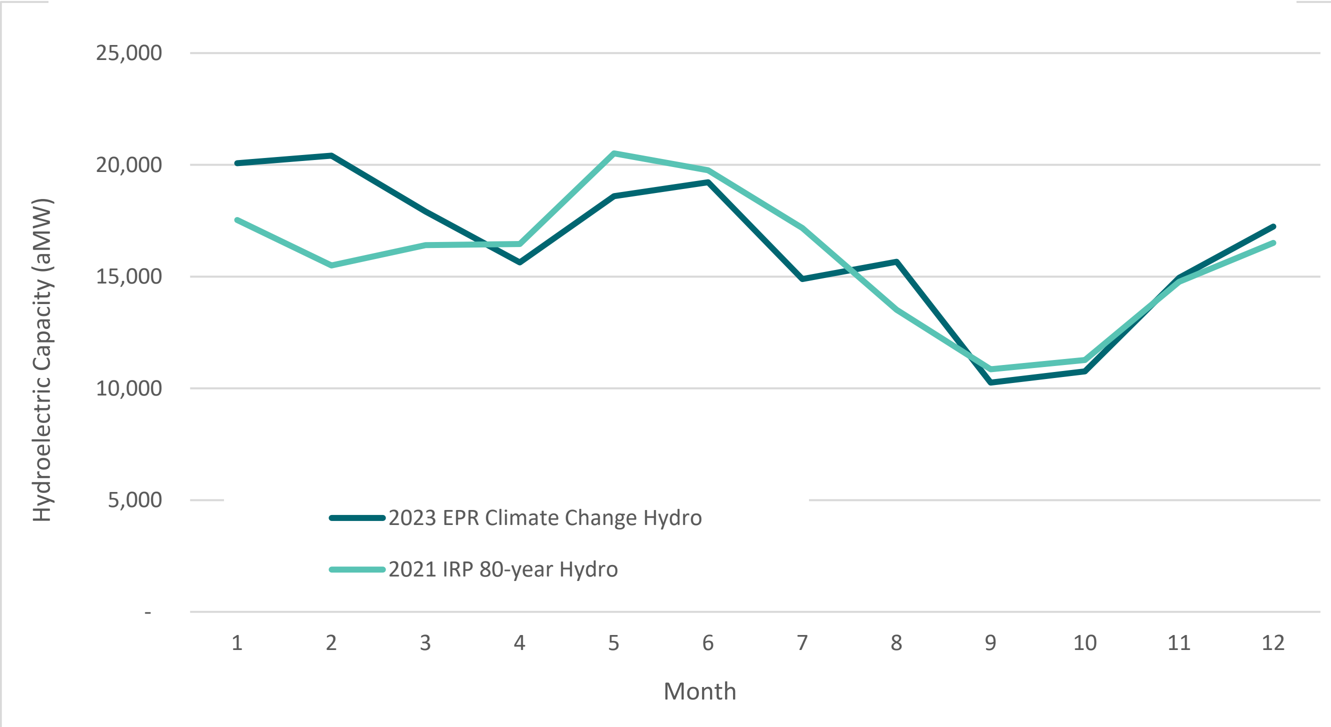
We held the average hydroelectric forecast fixed for all the modeled years. Figure G.6 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year.

Figure G.5: Seasonal Regional Demand for the Pacific Northwest, 2023 Electric Progress Report and 2021 IRP



4 GENESYS Model (nwcouncil.org)

Figure G.6: Pacific Northwest Climate Change Hydroelectric Forecast



3.1.6. Climate Commitment Act

The Washington State legislature passed the Climate Commitment Act (CCA) in 2021, which goes into effect in 2023. The CCA is a cap and invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances of permitted emissions.

The resulting market establishes an opportunity cost for emitting greenhouse gases. We added a price to greenhouse gas emissions for emitting resources within Washington State to model this opportunity cost in the electric price forecast. We only added an emission price to Washington emitting resources to ensure the model does not impact the dispatch of resources outside Washington State that are not subject to the rule.

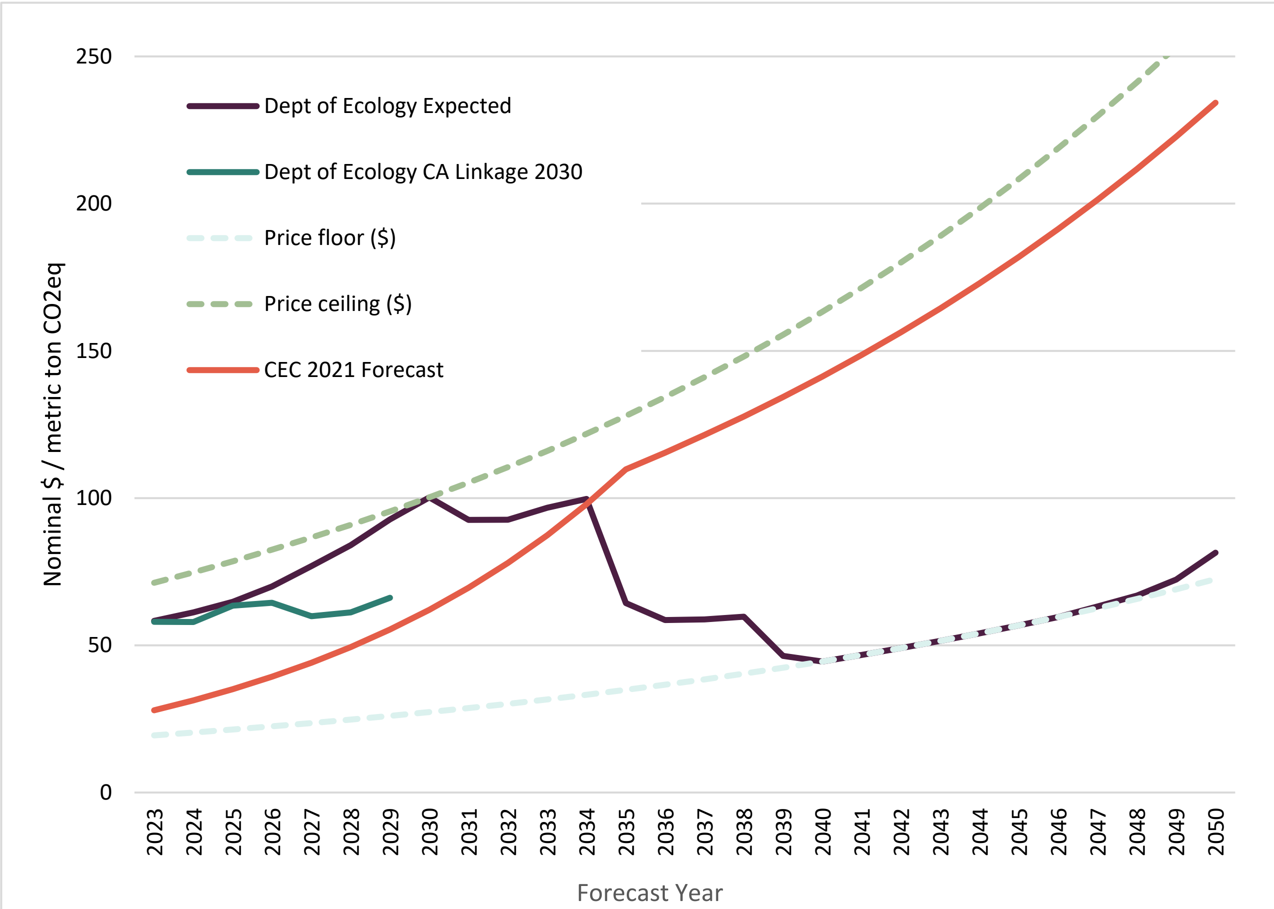
To accurately reflect all costs imposed by the CCA, we will add a hurdle rate on market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_{2eq} per MWh.[5]

Figure G.7 presents the allowance prices considered in the electric price forecast. The expected prices of the Washington State Department of Ecology (Ecology) represent the predicted emission price, assuming no linkage to the California carbon market. We suggest that linkage to the California carbon market is the most likely scenario and has adopted a hybrid scheme that begins with pricing at the rate specified by the Department of Ecology California

5 RCW 19.405.070

Linkage 2030[6] case, then transitions to the California Energy Commission (CEC) 2021 Integrated Energy Policy Report[7] allowance price forecast for the remainder of the modeling horizon.

Figure G.7: Climate Commitment Act Allowance Prices



4. Electric Price Forecast Results

Figure G.8 compares the annual average Mid-C wholesale electric price from the 2017 IRP to the 2023 Electric Report and the historic Mid-C wholesale electric price. Several factors contribute to the increase in electric prices from the 2021 IRP to the 2023 Electric Report:

1. **Natural gas prices**
   Natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices.

2. **Transmission constraints**
   In the 2023 Electric Report, we modeled the WECC as a 34-zone system instead of the 16-zone system

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6 Preliminary Regulatory Analyses for Chapter173-446 WAC, Climate Commitment Act Program

7 2021 Integrated Energy Policy Report (ca.gov)

modeled in the 2021 IRP. The increased number of zones increases transmission links within the model and increases wheeling costs as electricity is transported between zones, resulting in higher electricity prices.

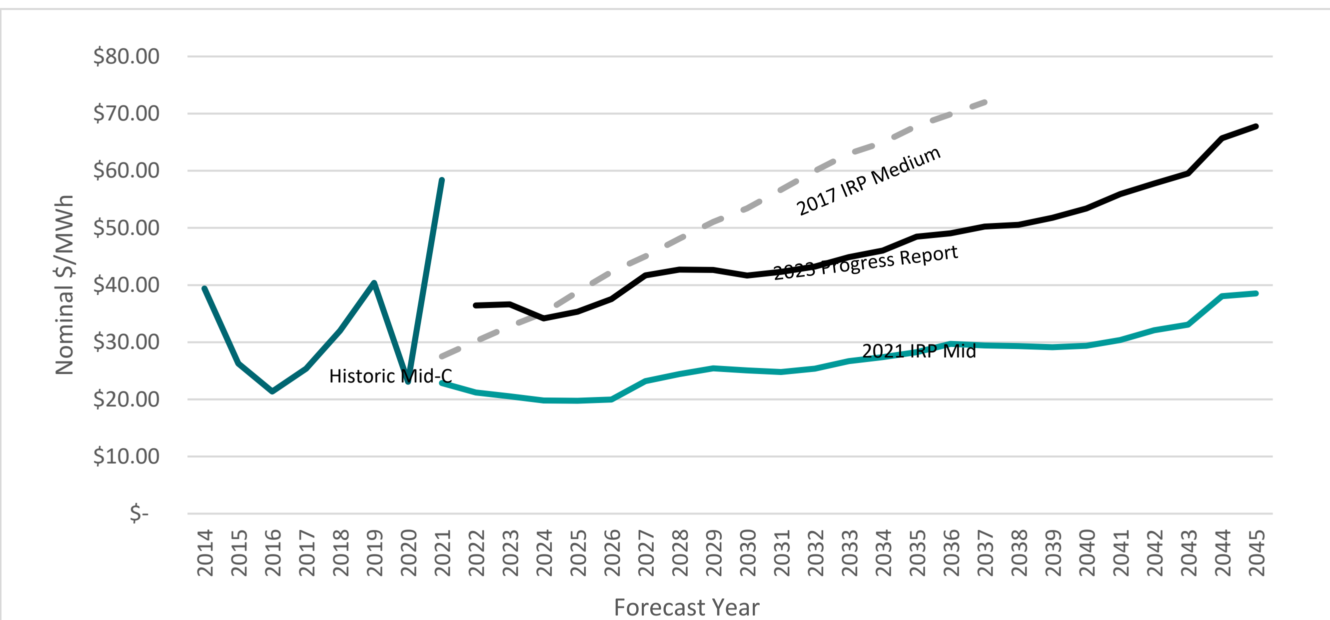
3. **Clean energy needs modeling**

   Clean energy requirements accounted for existing and new resources in the 2023 Electric Report, whereas in the 2021 IRP, only new resources contributed to the clean energy targets. The method used in the 2021 IRP may have understated the contribution of existing resources and, therefore, overbuilt new solar resources, which resulted in excess hours with low-cost power, artificially driving prices lower. The method we used in this report resulted in fewer renewable energy additions to the WECC, which results in a tighter energy market and higher prices.

4. **Storage**

   Resources that store energy (e.g., batteries) were unavailable in the 2021 IRP electric price model, resulting in overbuilding of wind and solar resources to provide non-emitting capacity. Overbuilt wind and solar resources lead to lower wholesale electric prices as more hours fill with zero-cost power from these renewable resources. We added storage as an available resource in the 2023 Electric Report, which allows us to shift load and generation and dramatically reduces the number of renewable resources required to meet the load. This scenario creates a tighter market driving up wholesale electric prices overall. Storage can help reduce very high prices through arbitrage and load/generation shifts resulting in more moderate average prices.

Figure G.8: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time



Despite the addition of storage resources, volatility is still present in the wholesale electric price results for the 2023 Electric Report. Price volatility results from the substantial buildout of renewable resources across the WECC.

Figure G.9 shows electric price volatility over a day for each month of the year. Strong morning and evening peaks are present throughout the modeling horizon and will become particularly extreme in the summer months by 2045.

Figure G.10 presents volatility across all hours of each year of the modeling horizon. Price spikes become increasingly common in the latter years of the analysis.

Figure G.9: Daily Price Volatility by Month for the Years 2023, 2030, and 2045

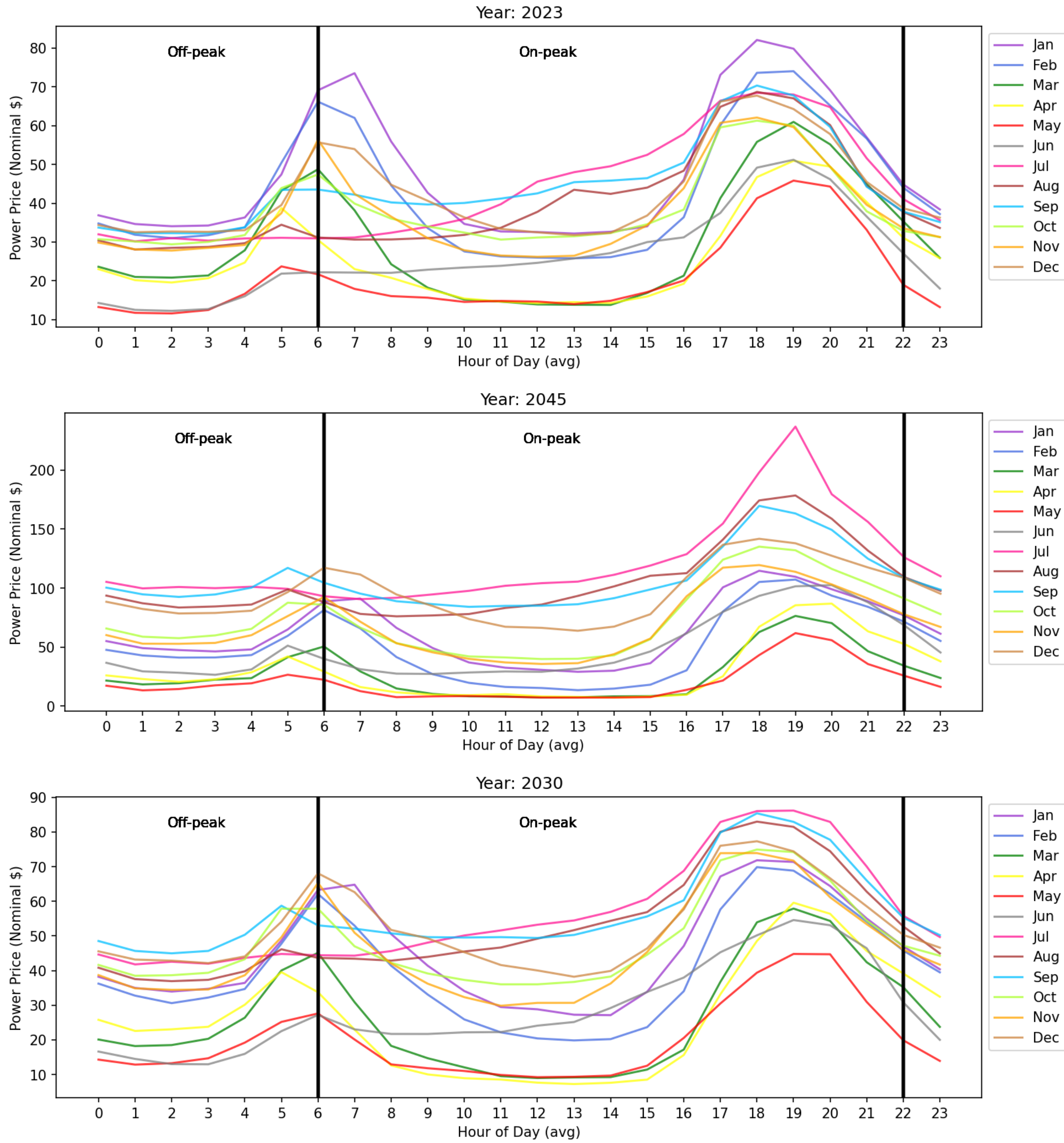
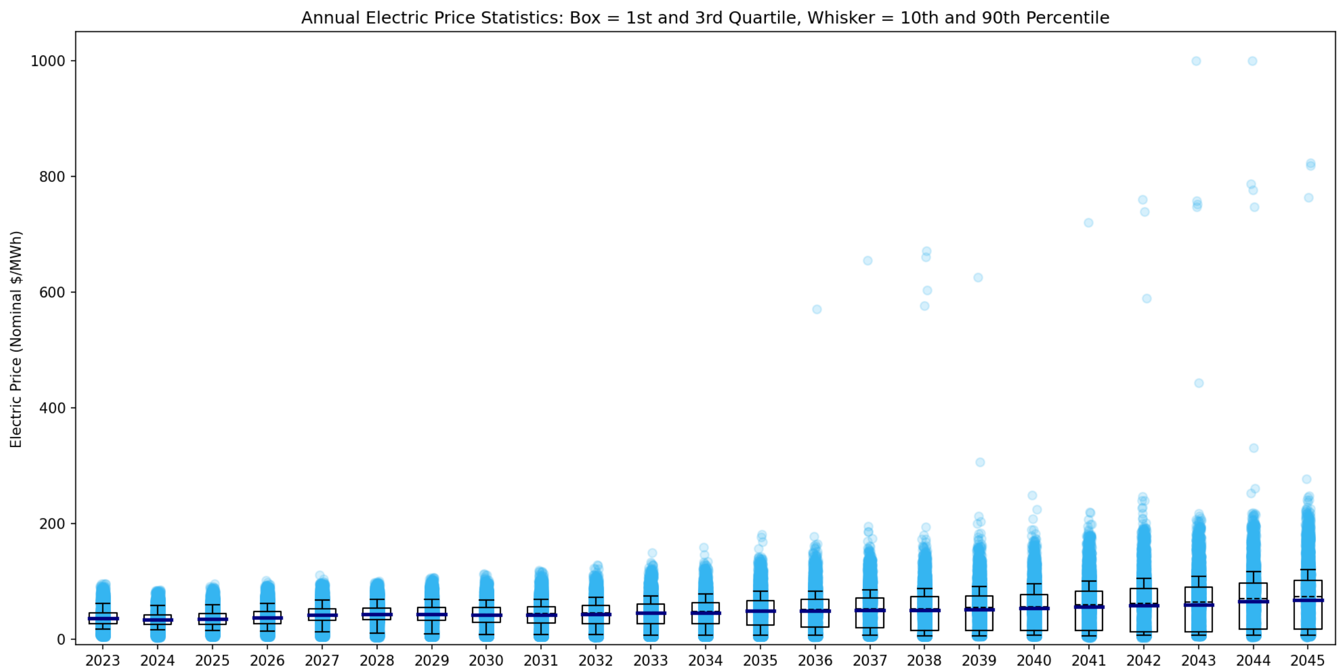


Figure G.10: Hourly Electric Prices over the Modeling Horizon



5. Electric Price Stochastic Analysis

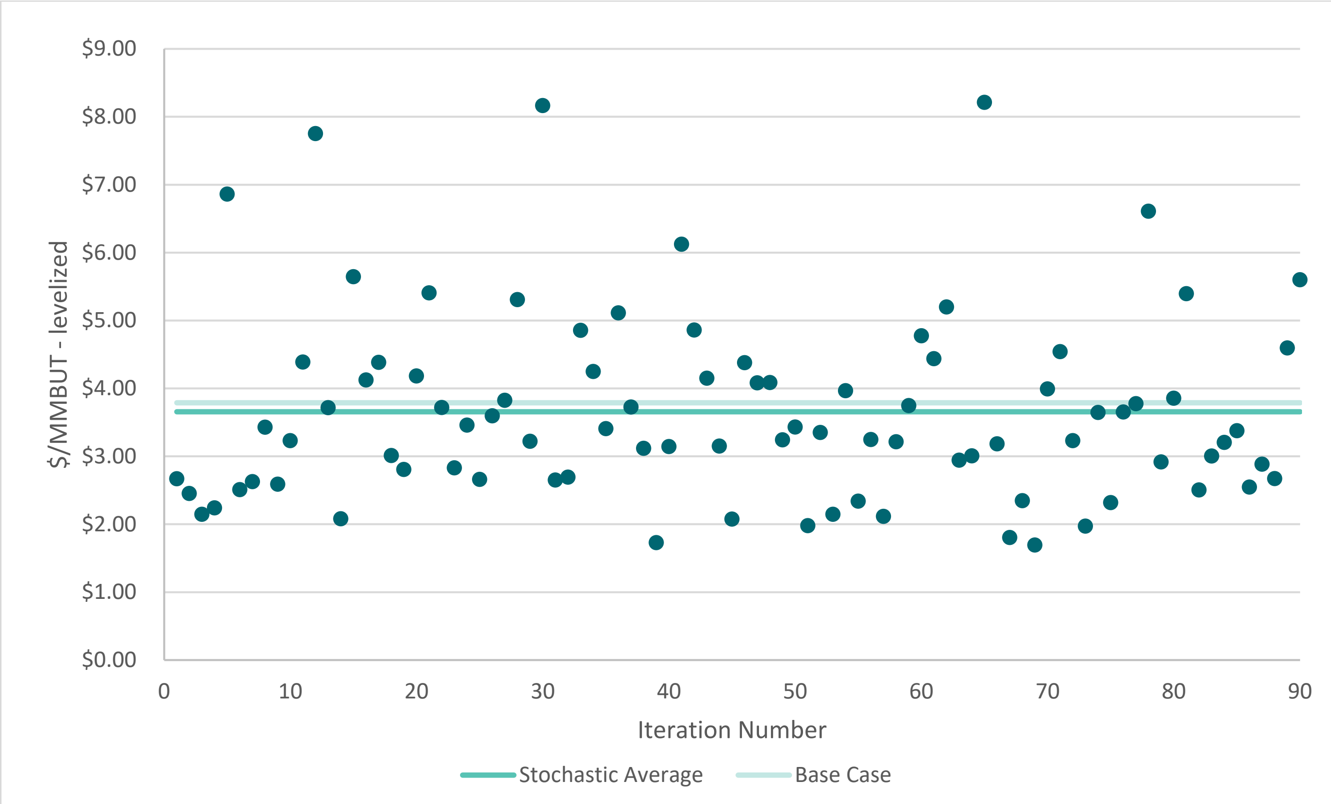
We use AURORA, a production cost model that utilizes electric market fundamentals to generate electric price draws. AURORA uses a Monte Carlo risk capability that allows users to apply uncertainty to a selection of input variables. The user can add variable input assumptions to the model as an external data source, or AURORA can generate samples based on user statistics on a key driver or input variable. This section describes the model input assumptions we varied to generate the stochastic electric price forecast.

5.1. Stochastic Natural Gas Price Inputs

We relied on AURORA's internal capability to specify distributions on select drivers, such as natural gas prices, to generate samples from a statistical distribution. The risk factor represents the model's adjustment to the base value for the specified variable for the relevant time. To calculate the risk factor on natural gas prices, we calculated the correlation of natural gas prices from Sumas, Rockies (Opal), AECO, San Juan, Malin, Topock, Stanfield, and PGE City Gate to Henry Hub with data from Wood Mackenzie's Spring 20222 Long Term View Price Update.

We also evaluated each hub's slow, medium, and high natural gas prices to determine each calendar month's average and standard deviation. We used the standard deviation as a percent of the mean for each calendar month as an input to AURORA for risk sampling. Figure G.11 illustrates the annual draws and the levelized 20-year Sumas natural gas price $/MMBtu generated by the AURORA model.

Figure G.11: Levelized 20-year Sumas Natural Gas Price $/MMBtu



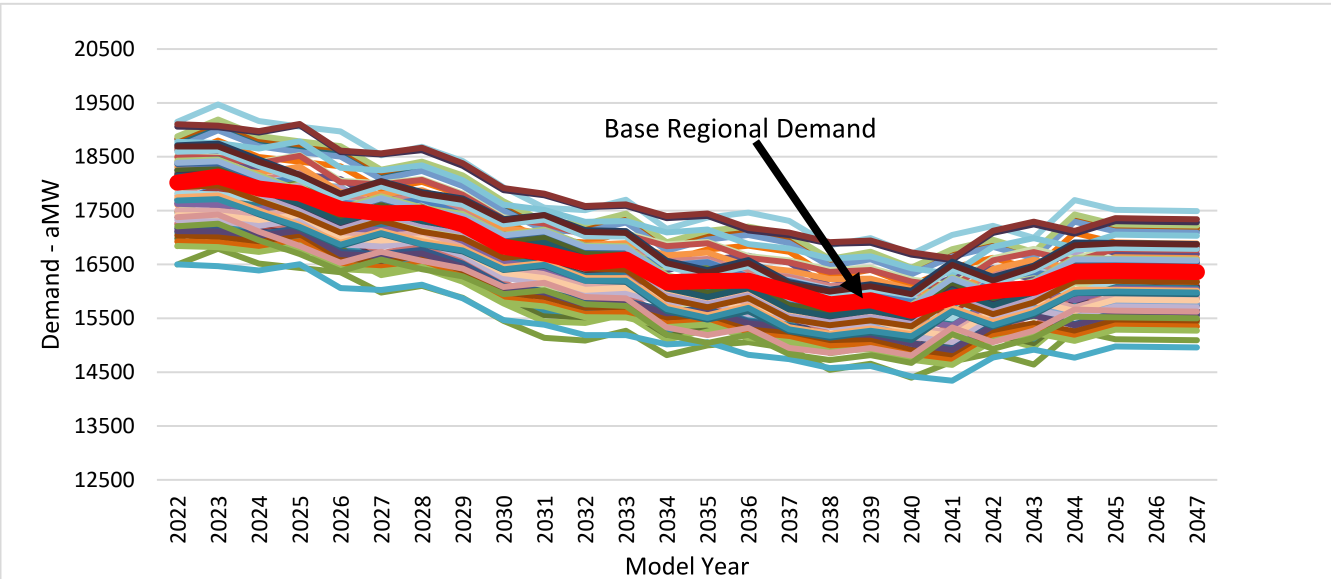
5.2. Stochastic Regional Demand

Like natural gas prices, we relied on AURORA's internal capability to generate samples from a statistical demand distribution. We evaluated low, medium, and high regional demand forecasts used in the deterministic price forecasts to determine the standard deviation as a percent of the mean for the modeling horizon. Table G.1 displays the 23-year levelized demand and the calculated standard deviation for the region. We used the standard deviation as an input to AURORA for the risk sampling of the entire WECC. Figure G.12 illustrates the 90 draws of demand AURORA generated for the Pacific Northwest.

Table G.1: 24-year Levelized Demand Statistics for PNW

2023 Electric Price Forecast Statistic	Quantity
Low - mean(aMW)	18,557
Medium - mean (aMW)	20,023
High - mean (aMW)	21,484
Mean of means	20,021
St Dev	1,195
St Dev Percent	0.06

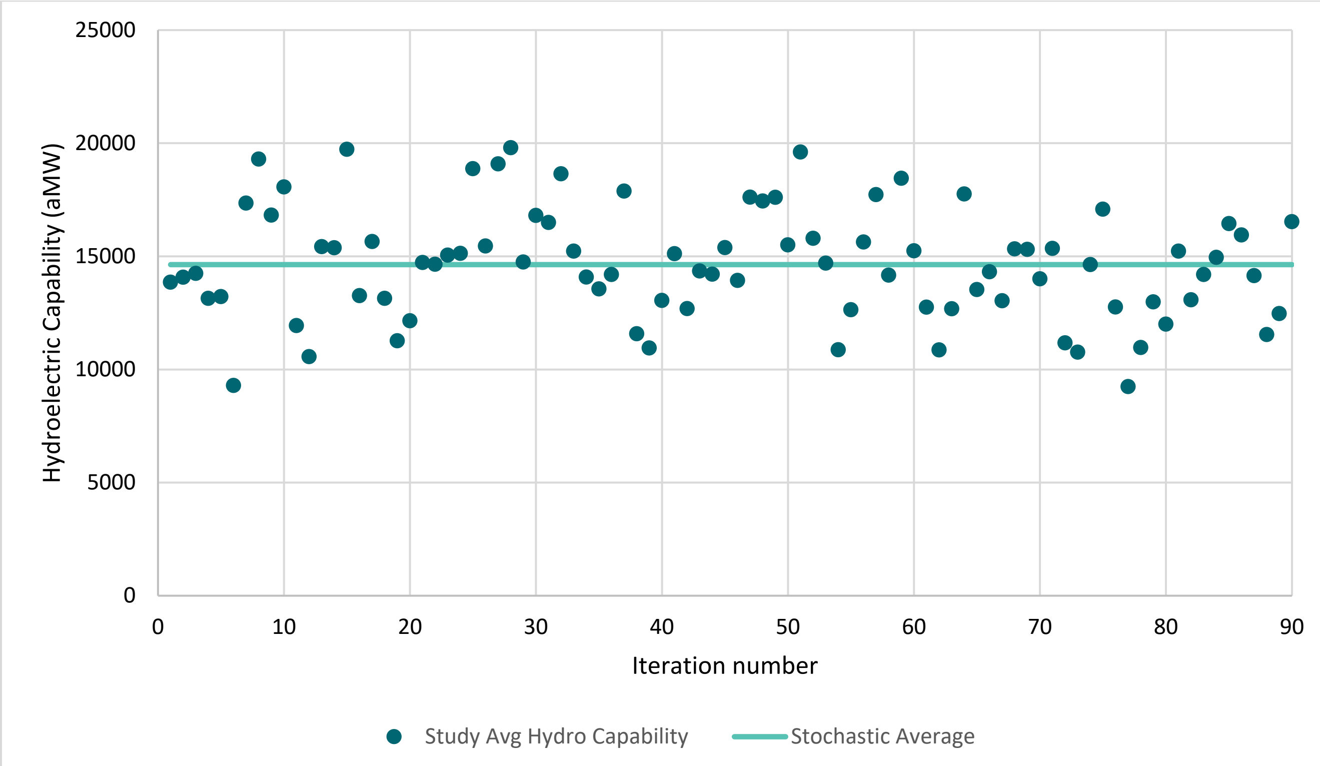
Figure G.12: Pacific Northwest Demand Draws (aMW)



5.3. Stochastic Hydroelectric Inputs

We derived stochastic hydroelectric inputs for this report's electric price forecast from the climate change hydroelectric data in this appendix. We obtained hydroelectric generation estimations for three climate change models with thirty years of data available for each model for 90 unique hydroelectric draws used in the stochastic analysis. Figure G.1 provides the 90 draws of hydroelectric capability for the Pacific Northwest.

Figure G.13: Hydroelectric Capability for the Pacific Northwest for 90 Iterations



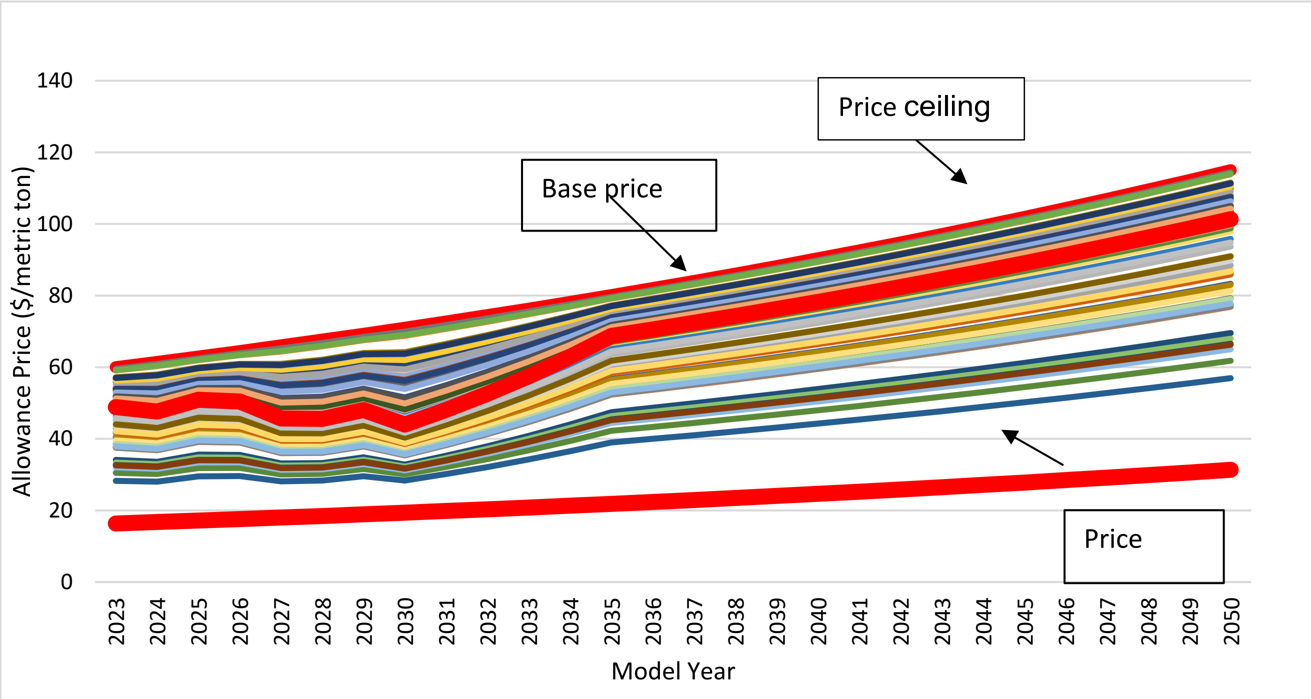
5.4. Stochastic Wind Inputs

Energy Exemplar developed wind shapes in the default AURORA database relying primarily on generation estimates from the National Renewable Energy Laboratory's (NREL) Wind Integration National Database (WIND) 2014 Toolkit, using data from the years 2007–2012. We averaged the generation from clusters of NREL wind sites with similar geography and capacity factors to form each delivered wind shape. For each wind region, we developed hourly shapes with capacity factors appropriate for three wind classes, low, medium, and high. For the electric price stochastic model, we randomly assigned an appropriate regional shape a low, medium, or high wind class for each wind project modeled in the analysis.

5.5. Stochastic Climate Commitment Act Prices

We generated 90 draws of allowance prices to represent the impact of the Climate Commitment Act in the stochastic electric price model. The ensemble price described earlier in this appendix was used as a basis and varied between the Washington Department of Ecology allowance price floor and ceiling.

Figure G.14: Climate Commitment Act Allowance Prices — 90 Iterations



5.6. Stochastic Electric Price Forecast Results

AURORA forecasts market prices and operations based on the forecasts of key fundamental drivers such as demand, fuel prices, and hydroelectric conditions. AURORA can generate 90 iterations of electric price forecast using the risk sampling for demand, fuel, and the pre-defined iteration set hydro and wind. Figure G.15 and Figure G.16 provide the stochastic electric price forecasts' annual and levelized power prices.

Figure G.15: Annual Electric Price Stochastic Results

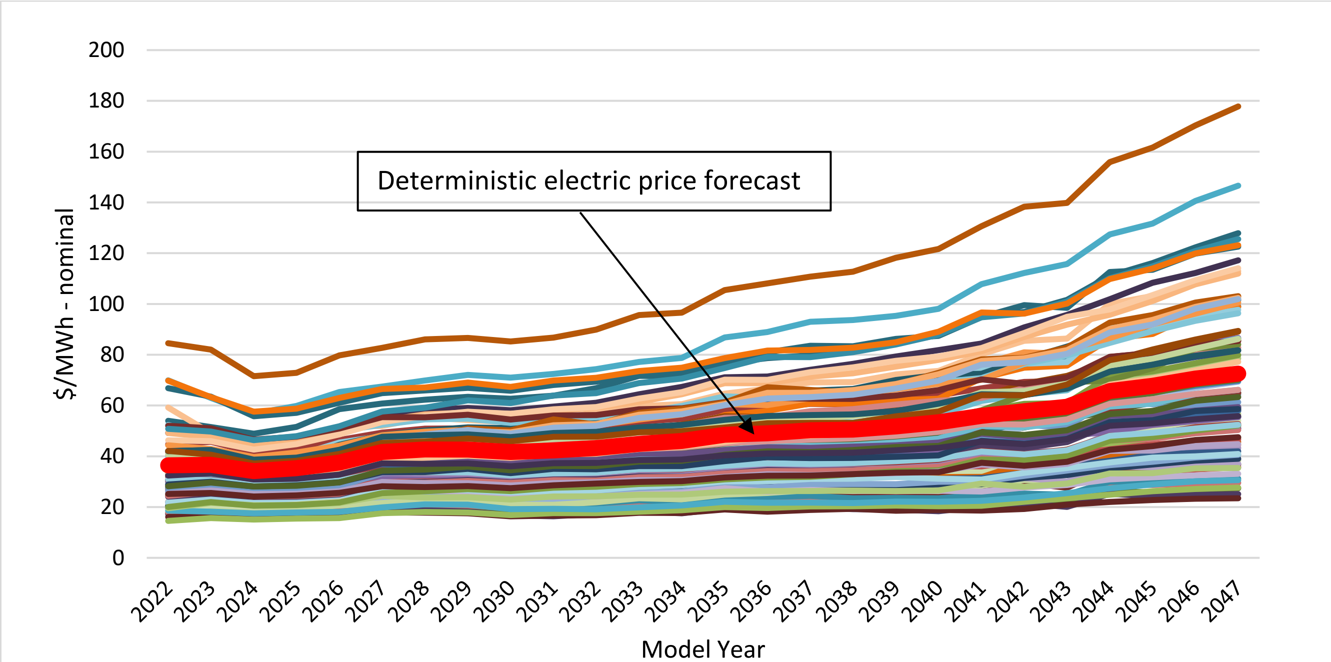
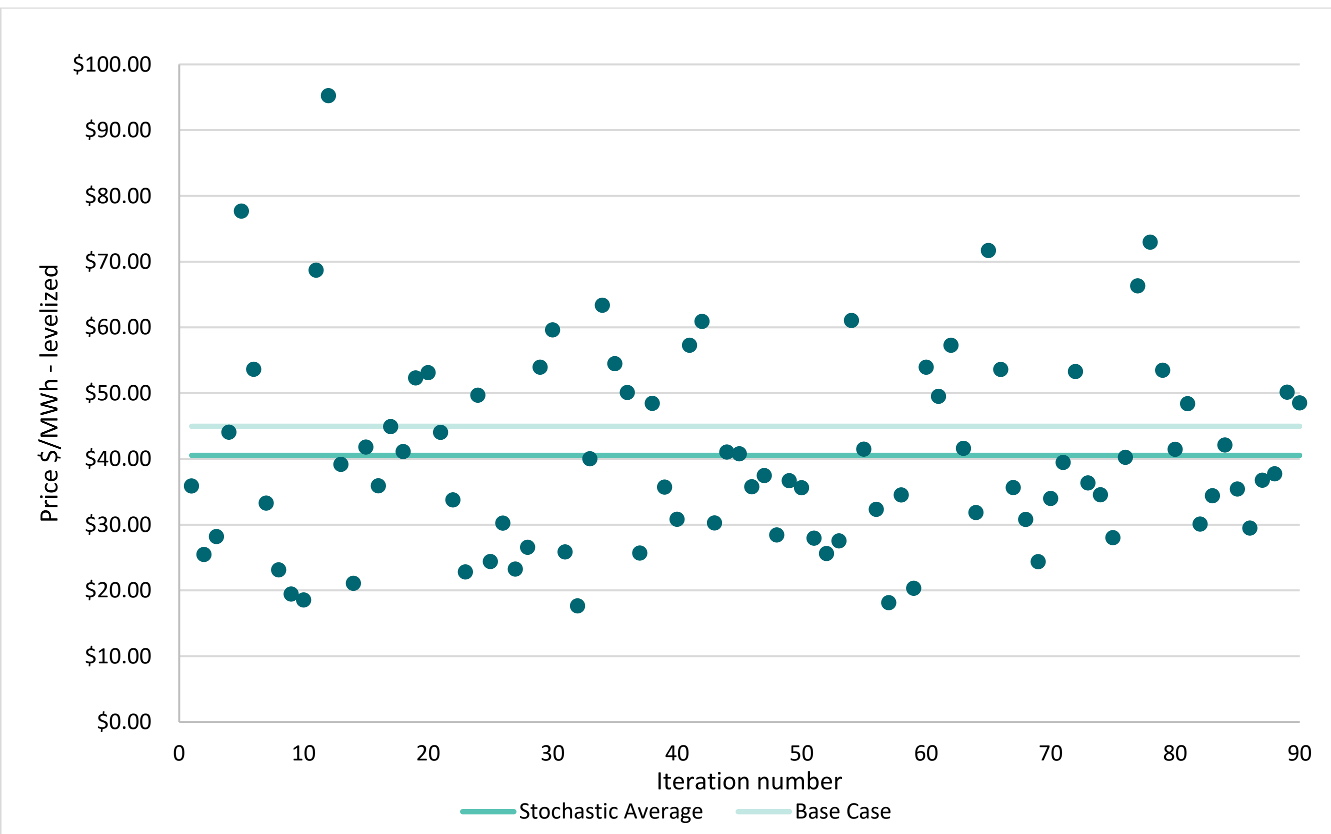


Figure G.16: Levelized Stochastic Electric Price Forecast Results - 90 Iterations



ELECTRIC ANALYSIS AND PORTFOLIO MODEL

APPENDIX H

PSE PUGET SOUND ENERGY

Contents

1. Introduction....1

2. AURORA Electric Price Model....2

3. AURORA Portfolio Model....2

3.1. Long-term Capacity Expansion Model....3

3.2. Optimization Modeling....4

3.3. System Constraints....6

3.4. Model Settings....8

5.1. Resource Value Decisions....11

6. Modeling Inputs....12

6.1. Forecasts....12

6.2. Resource Groups....12

6.3. Capital Cost Calculations....13

6.4. Social Cost of Greenhouse Gases....14

6.5. Climate Commitment Act....15

7. Embedding Equity....16

7.1. Modeling....17

7.2. Data Collection....18

7.3. Normalization....19

7.4. Aggregation....19

7.5. Analysis....19

7.6. Interpretation....20

8. Financial Assumptions....21

8.1. Tax Credit Assumptions....21

8.2. Discount Rate....21

8.3. Inflation Rate....22

8.4. Transmission Inflation Rate....22

8.5. Gas Transport Inflation Rate....22

8.6. Transmission and Distribution Costs....22

9. AURORA Stochastic Risk Model....22

9.1. Development of Stochastic Model Inputs....23

9.2. Stochastic Electric Price Forecast....24

9.3. Stochastic Portfolio Model....25

9.4. Electric and Natural Gas Prices....25

9.5. Hydroelectric Variability....25

9.6. Electric Demand 26
9.7. Wind and Solar Variability....26
9.8. Forced Outage Rates 27
9.9. Stochastic Portfolio Results....27
10. PLEXOS Flexibility Analysis Model 27
10.1. PLEXOS Simulation Phases....28
10.2. PLEXOS Model Inputs....29
10.3. Flexibility Benefit....30
11. Avoided Costs 32
11.1. Capacity....32
11.2. Levelized Cost of Energy....34
11.3. Deferred Transmission and Distribution Cost....38
11.4. Avoided Costs of Greenhouse Gas Emission....38
11.5. Avoided Cost of Capacity 39
11.6. Schedule of Estimated Avoided Costs for PURPA....40

1. Introduction

Puget Sound Energy uses three models in our electric integrated resource planning: AURORA, PLEXOS, and a stochastic resource adequacy model. This appendix provides a detailed description of those models and our analyses.

We use AURORA in several ways:

1. To analyze the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch.
2. To create optimal portfolios and test them to evaluate PSE's long-term revenue requirements for the incremental portfolio and the risk of each portfolio.
3. To create simulations and distributions for various variables in the stochastic analysis.

PLEXOS estimates the cost savings due to sub-hour operation for new generic resources.

We use resource adequacy models in the following ways:

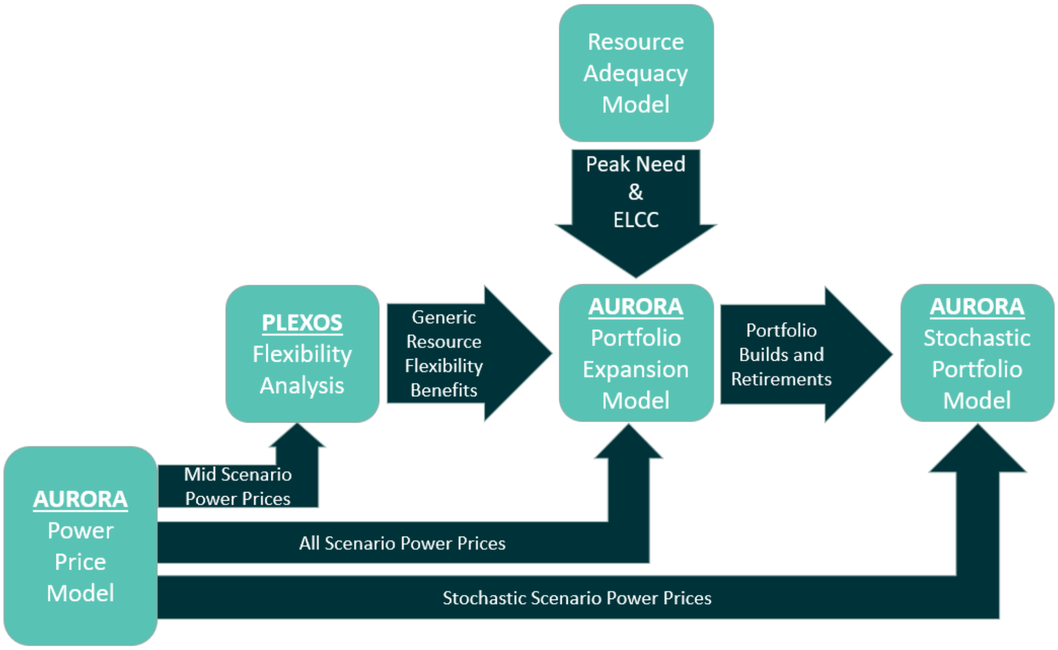
1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves.
2. To establish peak load planning standards to determine PSE's capacity planning margin.
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (effective load carrying capacity, or ELCC). The peak planning margin and ELCCs are inputs in AURORA for portfolio expansion modeling.

➔ A full description of resource adequacy modeling is in Chapter Seven: Resource Adequacy Analysis.

Figure H.1 demonstrates how the models are connected. We used the following steps to reach the least-cost portfolio for each scenario and sensitivity.

1. Create Mid-Columbia (Mid-C) power prices in AURORA for each electric price scenario.
2. Using AURORA's Mid Scenario Mid-C prices, run the flexibility analysis in PLEXOS to find the flexibility benefit for each generic supply-side resource.
3. Run a resource adequacy model to find the peak capacity need and ELCCs.
4. Using the electric price forecast, peak capacity need, ELCC, and flexibility benefit, run the portfolio optimization model in AURORA for new portfolio builds and retirements for each scenario and sensitivity portfolio.
5. Develop stochastic variables in AURORA around power prices, gas prices, hydro generation, wind generation, PSE loads, and thermal plant forced outages.

Figure H.1: Electric Analysis Methodology



2. AURORA Electric Price Model

We use Energy Exemplar's AURORA program to perform the electric price forecast process. AURORA is algebraic solver software used for decades in the utility industry to complete analyses and forecasts of the power system. The software allows us to perform comprehensive analyses and maintain a rigorous record of the data we used in the simulations.

We used the AURORA electric price model to forecast Mid-Columbia (Mid-C) wholesale electric prices over the planning horizon. The electric price model models all balancing authorities in the Western Electricity Coordinating Council (WECC).

➔ A full description of the electric price modeling is in Appendix G: Electric Price Models.

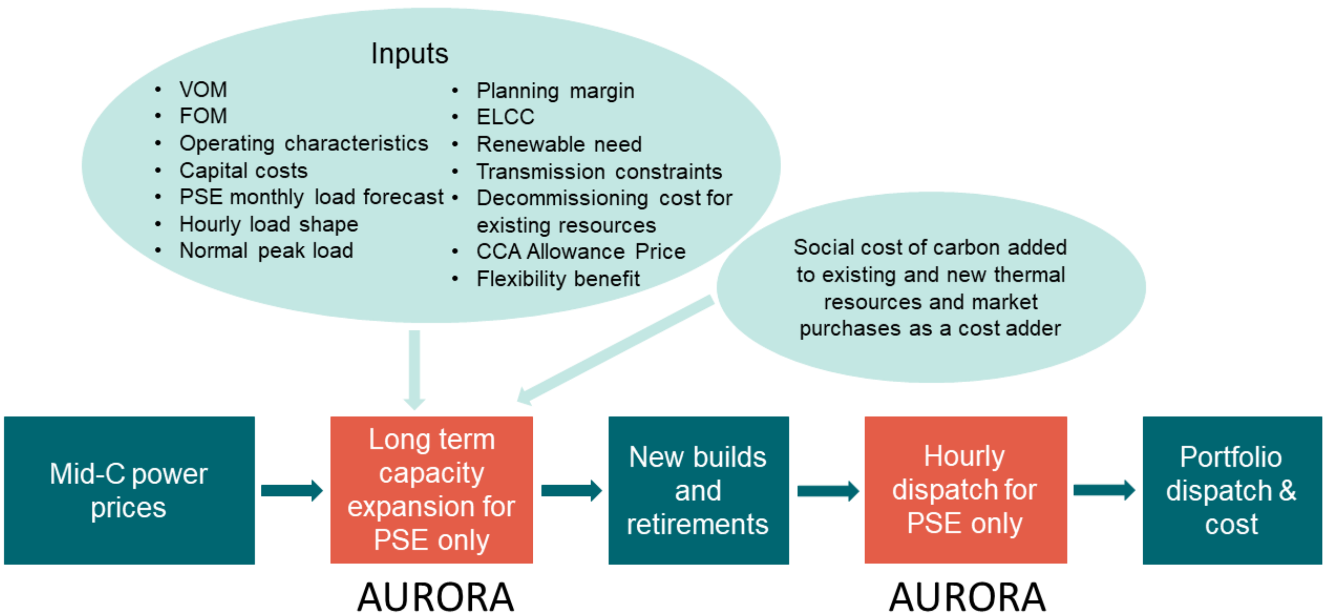
3. AURORA Portfolio Model

Puget Sound Energy's electric portfolio model follows a four-step process:

1. We use a long-term capacity expansion (LTCE) model to forecast which resources to install and retire over a long-term planning horizon to keep pace with energy and peak needs and to meet the renewable requirement in the Clean Energy Transformation Act (CETA).
2. The LTCE run produces a set of resource builds and retirements, that includes the impact of the social cost of greenhouse gases.

3. The final set of builds and retirements is then passed to the standard zonal model in AURORA to simulate every hour of the 22 years for a complete dispatch.
4. The standard zonal hourly dispatch then produces the portfolio dispatch and cost.

Figure H.2: Aurora Portfolio Model



3.1. Long-term Capacity Expansion Model

We used a long-term capacity expansion model to forecast the installation and retirement of resources over a long period. Over the study period of an LTCE simulation, the model may retire existing resources and add new ones to the resource portfolio. We used AURORA to perform the LTCE modeling process.

We began the resource planning process by deploying the LTCE model to consider the current fleet of resources available to PSE, the options available to fill resource needs, and the planning margins required to fulfill our resource adequacy needs. The model used the demand forecast to calculate the resource need dynamically as it performed the simulation. The LTCE model has the discretion to optimize the additions and retirements of new resources based on resource needs, economic conditions, resource lifetime, and competitive procurement of new resources.

We established which new resources would be available to the model before we ran it. In consultation with interested parties, we identified potential new resources and compiled the relevant information to these resources, such as capital costs, variable costs, transmission needs, and output performance. We did not include contracts in the modeling process, since that information is not publicly available for transparency in the 2023 Electric Report.

3.2. Optimization Modeling

Optimization modeling finds the optimal minimum or maximum value of a specific relationship, called the objective function. The objective function in PSE's LTCE model is to minimize the revenue requirement of the total portfolio — the cost to operate the fleet of generating resources.

The revenue requirement at any given time is:

$$RR_t = \sum_{Resource} (Capital\ Costs_{Resource} + Fixed\ Costs_{Resource} + Variable\ Costs_{Resource}) + Contract\ Costs + DSR\ Costs + Market\ Purchases - Market\ Sales$$

Where t is the point in time, and RR_t is the revenue requirement at that time.

Over the entire study period, the model seeks to minimize the *Present Value* of the total revenue requirement, defined as:

$$PVRR = \sum_{t=1}^{T} RR_t * [\frac{1}{(1+r)^t} + \frac{1}{(1+r)^{20}}] * \sum Resource\ End\ Effects$$

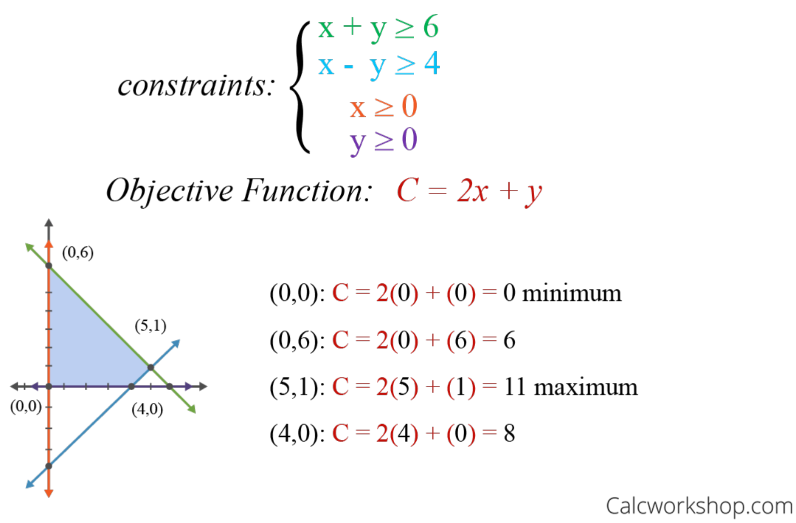
Where PVRR is the present value of the Revenue Requirement over all time steps, and r is the inflation rate used.

To reach optimization, we use various methods, including linear programming, integer programming, and mixed-integer programming (MIP). AURORA uses MIP, a combination of integer and linear programming.

3.2.1. Linear Programming

Linear programming, or linear optimization, is a mathematical model represented by linear relationships and constraints. Linear programming optimizes a value constrained by a system of linear inequalities. In a power system model, these constraints arise from the capacities, costs, locations, transmission limits, and other attributes of resources. The constraints combine to form the boundaries of the solutions to the objective function. Figure H.3 demonstrates a basic example of linear programming, where an objective function C(x,y) is minimized and maximized

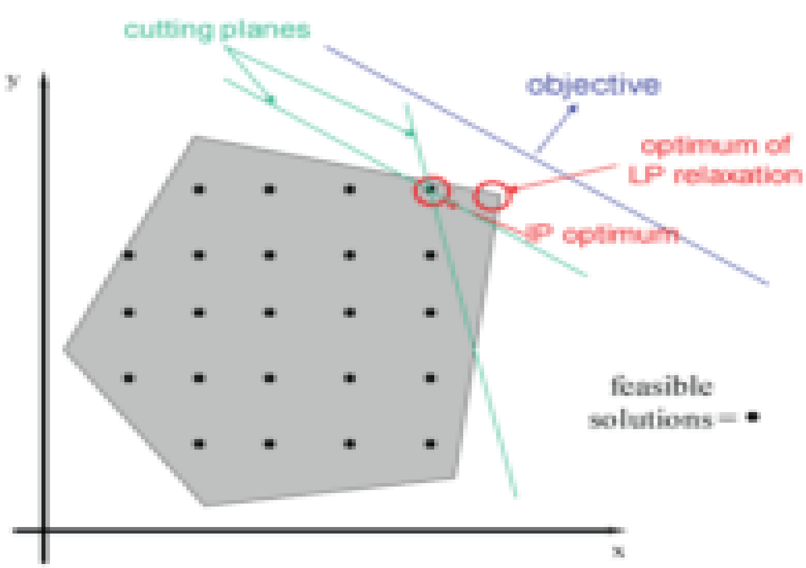
Figure H.3: Basic Example of Linear Programming



3.2.2. Integer Programming

Integer programming is another mathematical optimization method in which some or all the variables are restricted to integer values. The optimal solution may not be an integer value, but the limitation of the values in the model forces the optimization to produce a solution that accounts for these integer values. In the context of a utility, this may come in the form of having a discrete number of turbines that can be built, even though having a non-integer number of turbines will produce the optimal capacity. Figure H.4 shows an example of an integer programming problem. The optimal solution lies in the grey area, but only solutions represented by the black dots are valid.

Figure H.4: Visual Example of an Integer Programming Problem



3.2.3. Mixed Integer Programming

Mixed integer programming (MIP) combines linear and integer programming, where a subset of the variables and restrictions takes on an integer value. MIP methods are best suited for handling power system and utility models, as utilities' decisions and restraints are discrete (how many resources to build, resource lifetimes, how those resources connect) and non-discrete (the costs of resources, renewable profiles, emissions limitations).

In AURORA, MIP methods are the primary solver for completing all simulations, including the LTCE models. The software performs these methods iteratively and includes vast amounts of data, which makes the settings we use to run the model important in determining the runtime and precision of the solutions.

3.2.4. Iterative Solving

Optimization modeling can be deceptively simple when we break it down into sets of equations and solving methodologies. Limitations on computing power, the complexity of the model parameters, and vast amounts of data make a true solution impossible in many cases. To work around this, the LTCE model performs multiple iterations to converge on a satisfactory answer.

Given the complexity of the model, it does not produce the same results for each run. Over multiple iterations, AURORA compares each iteration's final portfolios and outputs with the previous attempt. If the most recent iteration reaches a certain threshold of similarity to the prior (as determined by the model settings) and has reached the minimum number of iterations, the program considers the solutions converged and provides it as the final output. If the model has reached the maximum number of iterations (also entered in the model settings), the last iteration will be considered the final output.

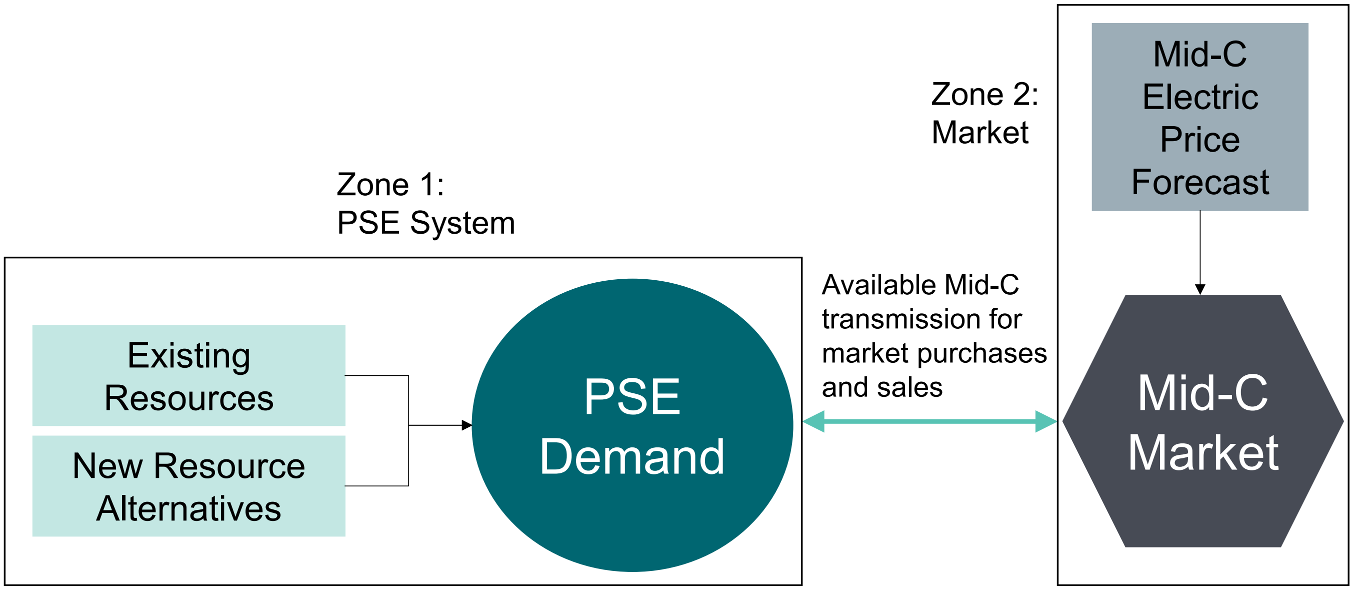
3.3. System Constraints

The solutions provided by optimizing the LTCE model seek to provide a path to meet PSE's load and minimize the total price of the fleet. Without constraints, the LTCE optimization model selects the resource that produces the most power per resource dollar and builds as many as needed. This trivial solution provides no useful insight into how the utility should manage real resources. Constraints allow the model to find an effective solution.

3.3.1. Zonal Constraints

We divided the model into zones. The only transmission limits in the standard model are between zones, though we may add more transmission constraints for most simulations at the expense of runtime and computing power. The zonal model works best for generation optimization. We can use the nodal model for more detailed transmission optimization. Given the current constraints on technology and computing power, there is no integrated model for generation and transmission. Figure H.5 shows how this two-zone system operates in AURORA, where zones are represented as rectangular boxes, and the arrows between them represent transmission links.

Figure H.5: PSE's Two-zone System Set-up in AURORA



We operate a two-zone system for all simulations. This system limits the amounts of market purchases we can make at any given time due to transmission access to the Mid-C market hub.

3.3.2. Resource Constraints

We defined resources in the model by their constraints. A resource must be defined by constraints to make its behavior in the model match real-world operating conditions.

- **Resource Costs** — Generic resource costs give the model information about the capital costs in addition to variable and fixed operation and maintenance costs to make purchasing decisions.
- **Operating Characteristics** — Generic resource inputs contain information about when the resources can operate, including fuel costs, maintenance schedules, and renewable output profiles. These costs include transmission installation.
- **Availability** — Resources have a finite lifetime and a first available and last available year they can be installed as a resource. Resources also have scheduled and random maintenance or outage events that we include in the model.

3.3.3. Renewable Constraints

The model must meet all legal requirements. The most relevant renewable constraints PSE faces are related to the Renewable Portfolio Standard (RPS) and CETA.

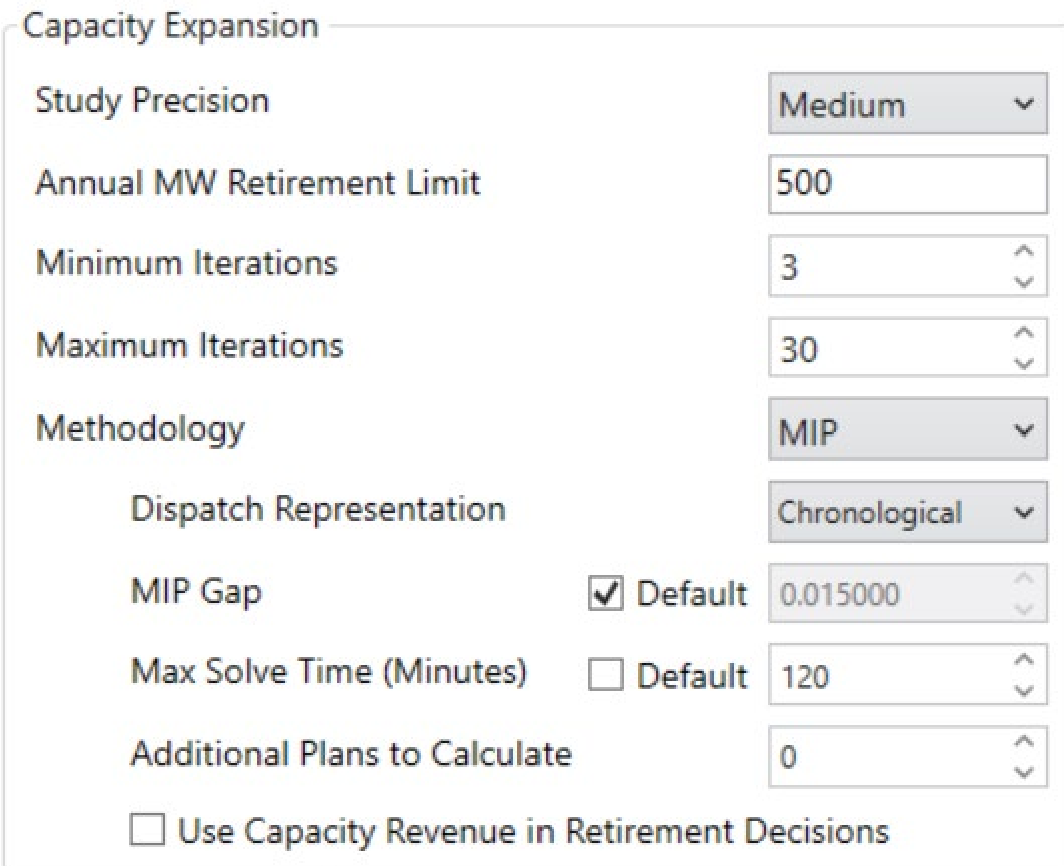
➔ See Chapter Five: Key Analytical Assumptions and Appendix D: Generic Resource Alternatives for more details on renewable constraints.

3.4. Model Settings

Our explanations for LTCE models rely heavily on the AURORA documentation provided by Energy Exemplar; we include relevant excerpts in the following section.

Before each LTCE model, we set parameters to determine how that simulation will run. The default parameters we used are in Figure H.6.

Figure H.6: Standard Aurora Parameters for PSE's LTCE Model



Note: These options are in the project file under Simulation Options → Long Term Capacity Expansion → Study Options → Long Term

3.4.1. Study Precision

During the iterative optimization process, the study precision controls when the model determines a solution is successfully converged. Instead of reaching one correct answer, the optimization process is multiple simulations that gradually converge on an optimized, stable answer given the model's assumptions. A visual representation of this process shows a model range gradually approaching an optimized solution. Users determine what is considered close enough to the absolute ideal answer by setting a percentage value for the study precision. Runtime limitations and computing power are the main drivers that limit the accuracy of a study.

The options for this setting include the following:

- High: Stops when the changes are less than 0.15 percent
- Medium: Stops when the changes are less than 0.55 percent
- Low: Stops when the changes are less than 2.5 percent

By experimenting with these settings, we determined the optimal setting is Medium, considering the tradeoff between runtime and precision.

3.4.2. Annual Megawatt Retirement Limit

The annual megawatt retirement limit restricts how much generating capacity can be economically retired in any given year. This setting does not include predetermined retirement dates, such as coal plant retirements, captured in the resources input data. We kept the default setting of 500 MW as a reasonable maximum for economic resource retirements to prevent outlier years where vast resources are retired.

3.4.3. Minimum Iterations

This setting specifies the minimum number of iterations that the simulation must complete. We set the minimum to three iterations to ensure that model decisions are checked.

3.4.4. Maximum Iterations

This setting specifies the maximum number of iterations that the simulation must complete. We set the maximum to 30 iterations to ensure the model's runtime does not become excessive. A simulation with more than 30 iterations will likely not converge on a usable solution.

3.4.5. Methodology

PSE uses the Mixed Integer Program (MIP) AURORA to perform the long-term capacity expansion model run.

4. Mixed Integer Program Methodology

The MIP methodology uses a Mixed Integer Program to evaluate resource build and retirement decisions. The MIP allows for a different representation of resources within the mode, leading to faster convergence times, more optimal (lower) system costs, and better handling of complex resource constraints. We employ the MIP methodology to take advantage of these benefits over traditional logic.

MIP-Specific Settings: Some settings within the MIP selection refine the performance of the MIP methods. We often use these settings at their default values, which are calculated based on the amount of data read into the AURORA input database for the simulation. The options are in the AURORA documentation and explained in Table H.1.

Table H.1: The MIP-specific Settings Used in the AURORA LTCE Model

Setting	Value Type	Definition
Dispatch Representation	Chronological	This methodology uses the dispatch of units in the chronological simulation (both costs and revenues) as the basis for the valuation of the build and retirement decisions. AURORA determines a net present value (NPV) for each candidate resource and existing resource available for retirement based on variable and fixed costs and energy, ancillary, and other revenue. Given the constraints, the method seeks to select the resources that provide the most value to the system. The formulation also includes internal constraints to limit the number of changes in system capacity between each iteration. These constraints are dynamically updated to help guide the solution to an optimal solution and promote convergence. We used this setting for the LTCE modeling process.
MIP Gap	Percent as a decimal value	This setting controls the precision level tolerance for the optimization. The default setting is generally recommended and will dynamically assign the MIP gap tolerance based on the study precision, objective setting, and potential problem size. When default is not selected, a value (generally close to zero) can be entered; the smaller the value, the harder the optimization works to find solutions.
Max Solve Time	Minutes	This setting controls the time limit for each LT MIP solution. Generally, using the default setting is recommended and will dynamically set the time limit based on the estimated difficulty of the problem (in most cases, about 30 minutes). If the default is not selected, the user can enter a value. If the time limit is reached, results may not be perfectly reproducible, so generally, a higher value is recommended.
Additional Plans to Calculate	Integer Value	When this value exceeds zero, AURORA will calculate additional plans after determining the final new build options and retirements. The program then adds a constraint to exclude the previous solutions, and then another MIP is formulated, and the solver returns its next best solution. The resource planning team sets this to zero.

5. Assumptions for all AURORA Models

The LTCE modeling process is a subset of the simulations we perform in AURORA. We keep most of these settings consistent across all models in AURORA, including the LTCE process. We may adjust sensitivities or simulations that are not converging properly. Table H.2 describes the settings we used in AURORA.

Table H.2: General Settings Used in all AURORA Models

Setting	Value Type	Definition
Economic Base Year	Year	The dollar year we set all currency to in the simulation. We used 2020 across all simulations through all IRP processes in AURORA for consistency, so we converted all inputs into 2020 dollars.

Setting	Value Type	Definition
Minimum Generation Backdown Penalty	Cost	Provides flexibility in modeling minimum generation segments and addresses linear programming solution infeasibility, which we can introduce due to hard minimum generation constraints. We set this value to $44.
Resource Dispatch Margin	Percentage	A value used to specify the margin over the cost of the resource required to operate that resource. We set this value to 0 percent.
Remove Penalty Adders from Pricing	Binary	When this option is selected, the model will adjust the zonal pricing by removing the effect of the non-commitment penalty on uncommitted resources and the minimum generation backdown penalty on committed or must-run resources. We used these penalty adders in the LP dispatch to honor commitment and must-run parameters; if this switch is selected, the model fixes resource output at the solved level before deriving zonal pricing without the direct effect of the adders. We selected this setting.
Include Variable O&M in Dispatch	Binary	We use this option to control the treatment of variable operation and maintenance (O&M) expenses. If selected, the variable O&M expenses are included in the dispatch decision of a resource. We selected this setting.
Include Emission Costs in Dispatch	Binary	This option allows the user to include the cost of emissions in the dispatch decision for resources. If not selected, the cost of emissions will not be included in the dispatch decision for resources. We selected this setting when modeling CO_2 price as a dispatch cost in select sensitivities.
Use Operating Reserves	Binary	This option determines whether the dispatch will recognize operating reserve requirements and identify a set of units for operating reserve purposes. When this option is selected, the model will choose a set of units (when possible) to meet the requirement. We selected this setting.
Use Price Caps	Binary	This option allows the user to apply price caps to specific zones in the database. If this option is selected, the model will apply specified price caps to the assigned zones. We selected this setting.

5.1. Resource Value Decisions

When solving for each time step of the LTCE model, AURORA considers the portfolio's needs and the resources available to fill those needs. The needs of the portfolio include capacity need, reserve margins, ELCC, and other relevant parameters that dictate the utility's ability to provide power. If there is a need, the model will select a subset of resources to fill that need.

At that time step in the program, each resource will undergo a small simulation to forecast how it will fare in the portfolio. This miniature forecast considers the operating life, capacity output, and scheduled availability of the resource. The model then considers resources that can best fulfill the needs of the portfolio on the merits of their costs.

Resource costs include the cost of capital to invest in the resource and fixed and variable O&M costs. Capital costs include the price of the property, physical equipment, transmission connections, and other investments required to acquire the physical resource. Fixed O&M costs include staffing and scheduled resource maintenance under normal conditions. Variable O&M costs include costs incurred by running the resource, such as fuel and maintenance costs accompanying use.

After we forecasted the costs of operating each resource, we compared them to find which had the least cost and served PSE's needs. The goal of the LTCE, an optimization model, is to provide a portfolio of resources that minimizes the cost of the portfolio.

6. Modeling Inputs

Several input assumptions are necessary to parameterize the model. These assumptions come from public and proprietary sources, and some we refined through our engagement process.

6.1. Forecasts

We cannot capture some attributes of the model in a single number or equation. Seasonal changes in weather, population behavior, and other trends that influence utility actions rely on highly time-dependent factors. We included a series of forecasts in the input assumptions to help provide these types of information into the model. Forecasts help direct overall trends of what will affect the utility in the future, such as demographic changes, gas prices, and environmental conditions. These forecasts are not perfect representations of the future, which is impossible to provide. However, they provide a layer of volatility that helps the model reflect real-world conditions.

Table H.3: Forecast Inputs and Sources

Input	Source	Description
Demand Forecast	Internal (see Chapter Six and Appendix F)	Energy and peak demand forecast for PSE territory over the IRP planning horizon.
Electric Price Forecast	Internal (see Appendix G)	The output of the AURORA electric power price model.
Natural Gas Price Forecast	Forward Marks prices, Wood Mackenzie (see Chapter Five)	A combination of the Forward Marks prices and Wood Mackenzie long-term price forecast.
Wind and Solar Generation	DNV	Solar and wind generation shapes dictate the performance of these renewable resources. Some forecasts are from existing PSE wind projects. Consultant DNV provides correlated wind and solar forecasts.

6.2. Resource Groups

Resources are split into two groups, existing and generic resources.

6.2.1. Existing Resources

We provided existing resources to the model as the base portfolio. Existing resources include those already in operation and those scheduled to be in the future. We also provided the model with scheduled maintenance and outage dates, performance metrics, and future retirement dates.

➔ See Appendix C: Existing Resource Inventory for more details of the existing resources modeled.

6.2.2. Generic Resources

Generic resources are the resources available to be added to the LTCE model. These resources represent real resources the utility may acquire in the future. Information about the generic resources includes the fuel used by the resources, costs, and availability. We also included transmission information based on the locations of the resources modeled.

➔ Details of the generic resources modeled are in Appendix D: Generic Resource Alternatives, and the numerical generic resource inputs in Appendix I: Electric Analysis Inputs and Results.

We simplified these resources to obtain representative samples of a particular resource group. For example, modeling every potential site where PSE may acquire a solar project would require prohibitive amounts of solar data from each location. To work around this issue, we used a predetermined site from different geographic regions to represent a solar resource in that area.

We developed the specific generic resource characteristics in partnership with IRP interested parties. As a result of feedback, we changed the costs of multiple resources to reflect more current price trends, and new resources were added, such as renewable and energy storage hybrid resources.

6.3. Capital Cost Calculations

The capital cost of a resource plays a large role in their consideration for acquisition by the model. Puget Sound Energy finances capital costs through debt and equity. The revenue requirement is the revenue the utility collects from ratepayers to cover operating expenses and the financing costs of the capital investment. The combined revenue requirement of all resources in the portfolio is the portfolio's total revenue requirement, the objective function the LTCE model seeks to minimize.

The revenue requirement is in the following equation:

$$\text{Revenue Requirement} = \text{Rate Base} * \text{Rate of Return} + \text{Operating Costs}$$

$$\text{Rate Base} = \text{Capital Investment}$$

$$\text{Rate of Return} = \text{Financing Costs (Set by the Commission)}$$

$$\text{Operating Costs} = \text{Fixed Operating Costs} + \text{Variable Operating Costs} + \text{Fuel} + \text{Depreciation} + \text{Taxes}$$

6.4. Social Cost of Greenhouse Gases

Per CETA requirements, we included the social cost of greenhouse gases (SCGHG) as an externality cost in the IRP process. We modeled the SCGHG as an externality cost added to the total cost of a given resource because CETA instructs utilities to use the SCGHG to make long-term and intermediate planning decisions. However, we also completed a portfolio sensitivity of the SCGHG as a variable dispatch cost based on requests from interested parties and as ordered by the Commission.

We revised how we applied the SCGHG for this 2023 Electric Report from the methodology presented in the 2021 IRP. For this report, we modeled the SCGHG as an externality cost adder with the following methodology:

1. We ran the LTCE model to determine portfolio-build decisions over the modeling timeframe. The LTCE model applied the SCGHG as a penalty to emitting resources (i.e., fossil-fuel resources) during each build decision and to market purchases.
    a. We applied the externality adder to emitting resources as follows:
        i. AURORA generates a dispatch forecast for the economic life of an emitting resource. The SCGHG does not impact this dispatch forecast to simulate real-world dispatch conditions.
        ii. The model summed the emissions of this dispatch forecast for the economic life of the emitting resource and applied the SCGHG to the total lifetime emissions.
        iii. The model then applied the lifetime SCGHG as an externality cost to the total lifetime cost of the resource.
        iv. The model based new build decisions on the total lifetime cost of the resource.
    b. We applied the externality cost to market purchases as follows:
        i. Modeled unspecified market purchases with an emission rate of 0.437 metric tons of CO_2eq per MWh.[1]
        ii. Multiplied the annual social cost of greenhouse gases by this emission rate and applied it as a hurdle rate added to the cost of market purchases in the LTCE model.
2. The LTCE model creates a portfolio of new builds and retirements. Since the LTCE runs through many simulations, we used a sampling method to decrease run time; so, in the final step, we passed the portfolio to the hourly dispatch model, which can model dispatch decisions at a much higher time resolution. The hourly dispatch model cannot make build decisions but more accurately assesses total portfolio cost to ratepayers. Since the SCGHG is not a cost passed to ratepayers, we did not include the SCGHG in the hourly dispatch modeling step.

[1] RCW 19.405.070

In the 2021 IRP, we calculated the fixed cost adder based on a separate AURORA dispatch model run to estimate the emissions expected for each emitting resource type. We then applied the fixed cost adder statically to subsequent simulations. In this progress report, we used the AURORA dispatch model's improved functionality to apply the SCGHG to emitting resources dynamically. In the revised methodology, AURORA dispatches emitting resources not subject to the SCGHG, then applies the SCGHG for all emissions over the resource's lifetime to the total cost of the resource when calculating the resource value for addition and retirement decisions. The 2023 model's SCGHG accounting is a marked improvement from the 2021 IRP methodology because the new accounting method more accurately represents the emissions of resources which may vary by simulation due to input changes or variation in the resource mix.

We applied the SCGHG to market purchases consistently in this report and the 2021 IRP — we added a hurdle rate to the cost of market purchases that reflects the unspecified market purchase emission rate. Modeling the SCGHG on market purchases as a hurdle rate impacts the dispatch of market purchases in the modeling framework. Reflecting the SCGHG as a dispatch cost on market purchases and as an externality cost to emitting resources introduces bias against market purchases into the model. We identified this bias late in the 2023 Electric Report modeling process and are actively working to identify a solution for future IRP cycles.

Interested parties requested that we include the SCGHG as a dispatch cost on emitting resources. We implemented this request as follows in Sensitivity 15:

1. Run a long-term capacity expansion (LTCE) model to determine portfolio-build decisions over the modeling timeframe. Apply the SCGHG in the LTCE model as a penalty to emitting resources during each build decision as a dispatch cost, which means the total energy produced by the resource decreased due to the higher dispatch cost.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simulations, use a sampling method to decrease run time, then pass the portfolio to the hourly dispatch model, which can model dispatch decisions at a much higher resolution. The hourly dispatch model cannot make build decisions but will more accurately assess total portfolio cost to ratepayers. We omitted the SCGHG in the hourly dispatch modeling step.

➔ See Chapter Eight: Electric Analysis for more information on sensitivity 15.

6.5. Climate Commitment Act

The Climate Commitment Act (CCA) is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market creates an opportunity cost for emitting greenhouse gases.

We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. We only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside

Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO2eq per MWh.[2]

We modeled the CCA allowance as a variable cost on both emitting resources and market purchases. This method means the impact of the CCA allowance price will impact the dispatch of these resources, reducing the amount of energy generated by these resources. We included the CCA allowance prices in the LTCE and hourly dispatch models because it is a direct cost on emitting resources and market purchases.

➔ See Chapter Five: Key Analytical Assumptions and Appendix I: Electric Analysis Inputs and Results for additional information on the CCA allowance price.

7. Embedding Equity

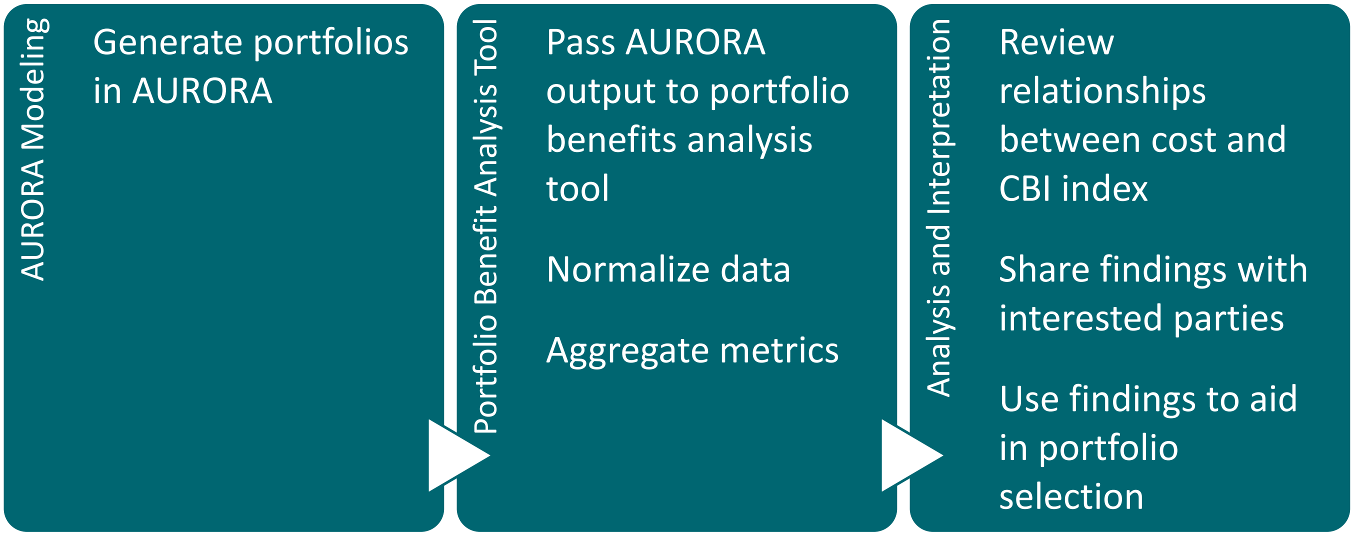
This section describes the methods we used in the 2023 Electric Report to quantify how different portfolios can improve equitable outcomes for named communities.

We analyzed these benefits outside the AURORA model with an Excel-based analysis called the portfolio benefit analysis. The AURORA program is a production cost model that seeks to identify the lowest-cost portfolio given constraints. Currently, elements of an equitable portfolio are difficult to translate into cost values; therefore, AURORA is ill-equipped to incorporate equity into its solution. Consequently, we developed the portfolio benefit analysis to obtain a relative measure of benefits for each portfolio analyzed as part of the planning process.

➔ We discuss the results in Chapter Eight: Electric Analysis. Appendix I: Electric Analysis Inputs and Results is the Excel workbook that contains the data and the numerical analysis results.

[2] RCW 19.405.070

Figure H.7: Elements of the Portfolio Benefit Analysis Process



The portfolio benefit analysis measures the number of customer benefits of each portfolio modeled. We use select metrics from the AURORA output to represent the Customer Benefit Indicators (CBIs) we developed as part of the 2021 Clean Energy Implementation Plan (CEIP), working collaboratively with our Equity Advisory Group (EAG) and customers.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative customer benefit indicators (CBIs) and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this 2023 Electric Report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA model could quantitatively evaluate them, i.e., AURORA already had a comparable metric.

We describe the elements of the portfolio benefit analysis in the following sections.

7.1. Modeling

The first step in the portfolio benefits analysis is to generate portfolios to review. Portfolios are a collection of generating resources PSE could use to serve electrical demand. First, we create a reference portfolio that represents the lowest-cost portfolio to satisfy the base modeling assumptions. Then we generate a variety of portfolios to represent a range of economic conditions, resource assumptions, and environmental regulations to learn how those changes impact the resource mix and cost of the portfolio.

➔ We describe the AURORA portfolio modeling throughout this appendix and provide results for each portfolio in Chapter Eight: Electric Analysis.

7.2. Data Collection

Following the modeling process, we collected targeted data from the AURORA output for each portfolio. We can measure many CBIs directly from this data, such as emissions and portfolio cost. However, AURORA does not generate job, customer, or participant data. The portfolio benefit analysis combines the technology-specific capacity built over the 22-year planning period with additional data to generate meaningful metrics to evaluate these CBIs.

- **Jobs**: The portfolio benefit analysis uses a technology-specific job per megawatt (MW) metric to convert the technology-specific capacity AURORA provides into a total number of jobs created for a given portfolio. The jobs/MW metric combines the 2022 U.S Energy and Employment Jobs Report[3] data with the technology-specific total capacity operating nationally, sourced from the 2022 Early Release EIA Forms 860[4] and 861[5].

- **Demand Response and Distributed Energy Resources (DER) participation**: We show the number of expected participants in demand response programs in PSE's 2022 Conservation Potential and Demand Response Assessments that we produced for this 2023 Electric Report and provided in Appendix E. Historic DER participation data is from the 2022 EIA Form 861M[6].

Table H.4 summarizes the CBIs, associated metrics, and data sources we evaluated in the portfolio benefit analysis tool.

Table H.4: Metrics and Data Sources in the Portfolio Benefit Analysis

CBI	Measurement Metric (Unit)	Data Source
Reduced greenhouse gas emissions	CO_2 (short tons)	AURORA output
Improved affordability of clean energy	Portfolio cost ($)	AURORA output
Improved outdoor air quality	Sulfur oxides (Sox), nitrogen oxides (Nox), and particulate matter (PM) (short tons)	AURORA output
Increased participation in Energy Efficiency, Distributed Energy Resources, and Demand Response programs	Customer in each program (count)	AURORA output PSE's 2022 Conservation Potential Assessment and Demand Response Assessment 2021 Early Release EIA Form 861M
Increase in the number of jobs	Jobs generated (count)	2022 U.S Energy and Employment Jobs Report and

3 https://www.energy.gov/sites/default/files/2022-06/USEER%202022%20National%20Report_1.pdf
4 https://www.eia.gov/electricity/data/eia860/
5 https://www.eia.gov/electricity/data/eia861/
6 https://www.eia.gov/electricity/data/eia861m/

CBI	Measurement Metric (Unit)	Data Source
		2021 Early Release and EIA Forms 860 and 861
Improved access to reliable, clean energy	Customers with access to storage resources (count)	AURORA output 2021 Early Release EIA Form 861M
Reduction in peak demand	Peak reduction through Demand Response (MW)	AURORA output

7.3. Normalization

The portfolio benefit analysis normalizes all metrics to 1) allow comparison between metrics with different units, such as emissions and job data, and 2) create an overall CBI index to compare portfolios and sensitivities. The portfolio benefit analysis normalizes metrics using a modified z-score, where we set the reference portfolio to equal zero, and each sensitivity converts to an index measuring the number of standard deviations from the reference portfolio. All positive indices indicate a more favorable CBI outcome than the reference portfolio.

7.4. Aggregation

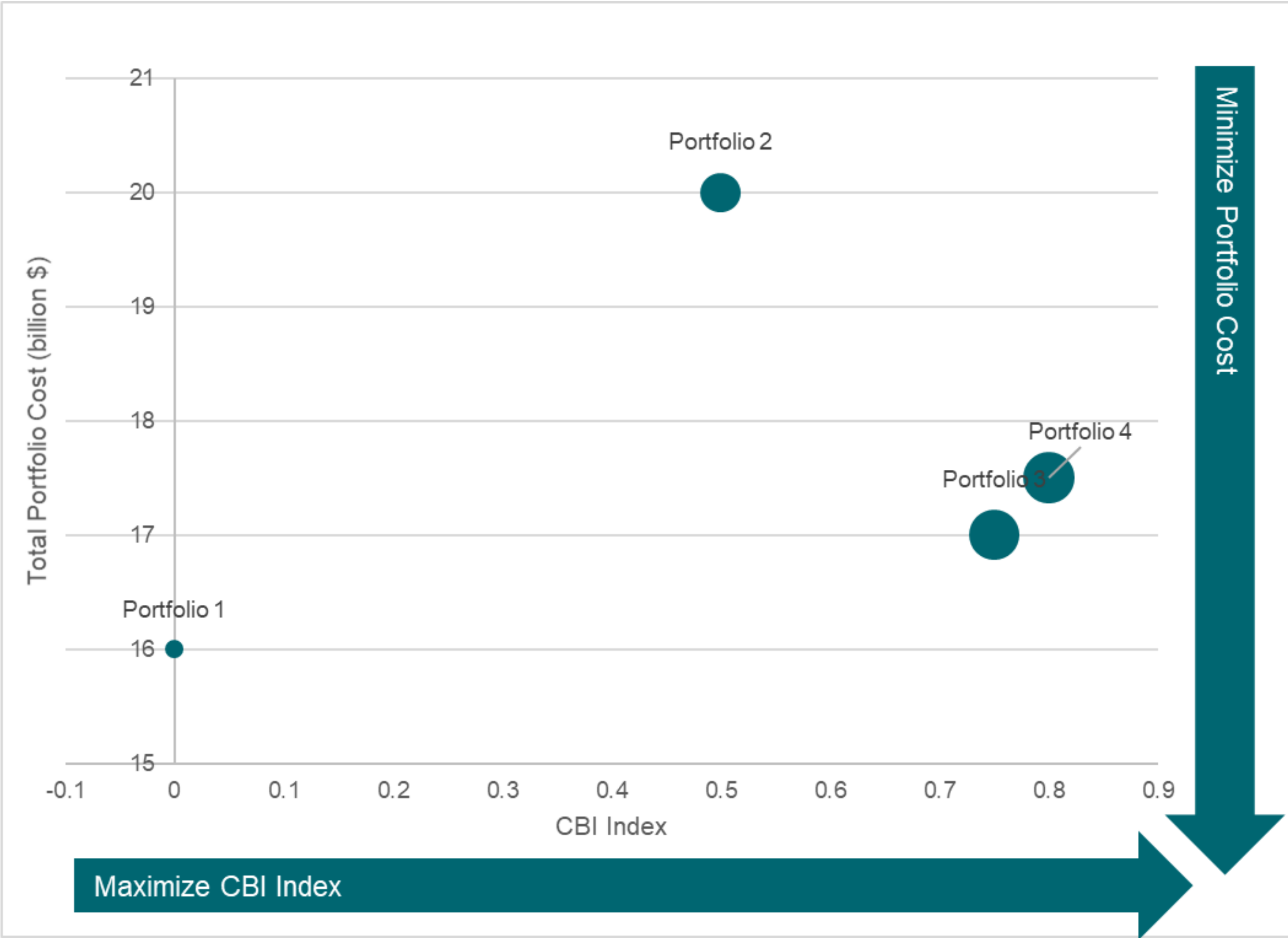
Following normalization, the portfolio benefit analysis combines all CBI indices into a single index for the portfolio using the arithmetic mean. The overall CBI index provides a single value representing the relative quantity of benefits each portfolio provides and facilitates direct comparison between the various portfolios.

7.5. Analysis

We plotted the overall index for each portfolio against the total portfolio cost. This plot illustrates the tradeoff between increasing CBI value and cost. Compared to the reference portfolio, the most efficient portfolios have the greatest CBI indices with minimal increase in portfolio cost.

Figure H.8 illustrates an example scenario where we analyzed four portfolios. We plotted the reference portfolio, Portfolio 1, near the origin. Portfolio 2 demonstrates an inefficient portfolio, where a moderate increase in the CBI index costs four billion dollars more than the reference portfolio. Conversely, Portfolios 3 and 4 illustrate more efficient portfolios, where the relative increase in the CBI index costs an additional one or one and a half billion dollars, respectively. The most efficient portfolios are near the bottom, right side of the plot. The point's radius illustrates the second indication of efficiency; the larger points indicate increased CBI value per dollar spent.

Figure H.8: Sample Portfolio Benefit Analysis Comparison Plot



7.6. Interpretation

Next, we further reviewed the details of the most efficient portfolios, considering the resource mix and the real-world applicability. In the example illustrated in Figure H.6, the relationship between Portfolios 3 and 4 shows a tradeoff between cost and CBI value, often referred to as an efficiency frontier. Portfolio 3 offers a lower cost, while Portfolio 4 offers a higher CBI value. In this case, we must review portfolio-build decisions and consider additional factors.

For example, if Portfolio 4 requires 1,000 MW of distributed rooftop solar installed by 2030, but this is infeasible due to a supply chain shortage and a deficit in interested and available participants, Portfolio 4 would not be selected as the preferred portfolio, even though it has the highest CBI index. Similarly, we would not automatically choose a sensitivity based on cost alone.

After reviewing an initial group of portfolios, we shared initial conclusions with internal and external parties to gain additional perspective on the candidate portfolios. The feedback from interested parties included recommendations that we analyze different portfolios that included or excluded specific resource types. We analyzed these other portfolios and added the results to the portfolio benefit analysis.

Because the portfolio benefit analysis uses a modified z-score methodology to convert raw data into an index, the index is subject to change by introducing new portfolios. Therefore, to minimize user bias, once a portfolio is analyzed, it will remain within the portfolio benefit analysis, even if we deem it inefficient or infeasible.

Further interpretation of the initial and new portfolios together provides context for selecting the preferred portfolio from a selection of candidate portfolios.

8. Financial Assumptions

As the portfolio modeling process takes place over a long-term timeline, we must make assumptions about the financial system the resources will operate in.

8.1. Tax Credit Assumptions

Before the Inflation Reduction Act (IRA), Production Tax Credit (PTC) and Investment Tax Credit (ITC) values were based on the start of construction with a four-year window to complete a qualifying project. We phased down the PTC and ITC, where PTC was set to expire in 2022, and ITC was ramped down to 10 percent indefinitely. The ramp-down created uneven investment decisions to capture the most value for the tax credits. The tax credits were technology specific: PTC for wind and ITC for standalone solar and solar paired with storage.

The IRA extended the PTC to 100 percent value and the ITC back to the maximum 30 percent value. The IRA now makes the PTC and ITC technology neutral. The IRA expanded the tax credits to include standalone storage and advanced nuclear.

There is a bonus incentive that may allow businesses to achieve more project-specific tax credit incentives. The additional credits are as follows:

- Ten percent for domestic consent
- Ten percent energy community credit
- Ten to twenty percent of low-income communities' projects under 5MW (ITC only)

The PTC provides tax credits based on a project's first 10 years of output. The current PTC rate is $26/MWh and is adjusted annually for inflation. Solar projects are now eligible for PTC, which is more economical than the ITC from our analysis.

We apply the 30 percent ITC to investments in a qualifying project. The ITC provides a large benefit for standalone storage, now providing a 30 percent discount on capital costs.

8.2. Discount Rate

We used the pre-tax weighted average cost of capital (WACC) from the 2019 General Rate Case of 6.8 percent nominal.

8.3. Inflation Rate

Unless otherwise noted, we used a 2.5 percent escalation for all assumptions. This is the long-run average inflation rate the AURORA model uses.

8.4. Transmission Inflation Rate

In 1996, the BPA rate was $1.000 per kW per year, and the estimated total rate in 2015 was $1.798 per kW per year. Using the compounded average growth rate (CAGR) of BPA Point-to-Point (PTP) transmission service (including fixed ancillary service Scheduling Control and Dispatch) from 1996 to 2015, we estimated the nominal CAGR inflation rate to be 3.05 percent annually.

8.5. Gas Transport Inflation Rate

Natural gas pipeline rates are not updated often, and recent history indicates the rates are 0 percent. We assumed zero inflation on pipeline rates because our major pipelines have declining rate bases, and we will incrementally price major expansions. We expect growth in service costs from operating costs and maintenance capital additions to be offset by declines due to depreciation.

8.6. Transmission and Distribution Costs

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Report included a T&D benefit of $74.70/kW-year for DER batteries. The model forecasted this estimated $74.70/kW-year based on our different transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described above.

9. AURORA Stochastic Risk Model

A deterministic analysis is a type of analysis where all assumptions remain static. Given the same set of inputs, a deterministic model will produce the same outputs. In PSE's resource planning process, the deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity. In this report, PSE modeled additional deterministic sensitivities, which allowed us to evaluate a broad range of resource options and associated costs and risks. The sensitivity analysis is a type of risk analysis. We can isolate how one variable changes the portfolio builds and costs by varying one parameter.

Stochastic risk analysis deliberately varies the static inputs to a deterministic analysis to test how a portfolio developed in the deterministic analysis performs concerning cost and risk across a wide range of possible future power prices, natural gas prices, hydro generation, wind generation, loads, and plant forced outages. By simulating the same portfolio under different conditions, we can gather more information about how a portfolio will perform in an uncertain future. We completed the stochastic portfolio analysis in AURORA.

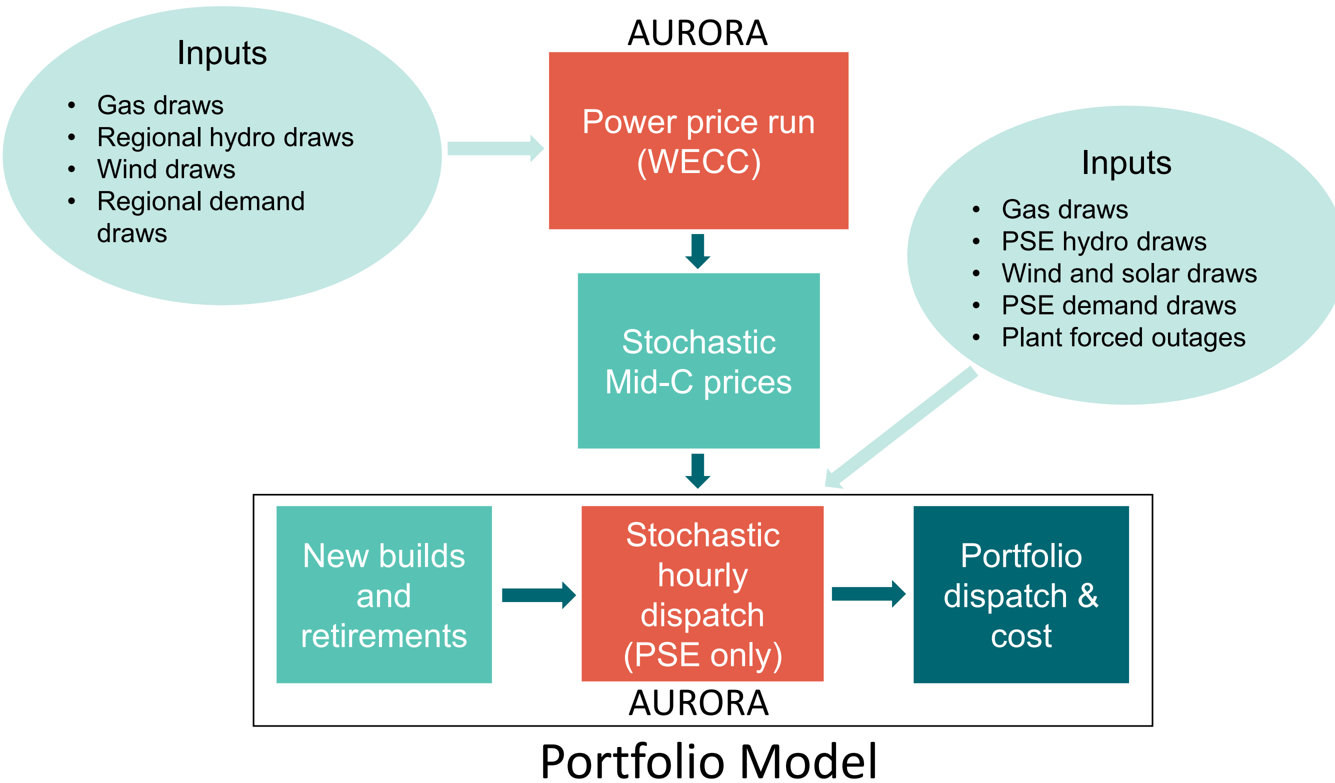
The stochastic modeling process aims to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of different forecasts, such as high prices, low hydroelectric, and the adverse impacts of their occurrence for any given portfolio.

The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations generate a distribution of resource energy outputs (dispatched to prices and must-take), costs, and revenues from AURORA. The stochastic inputs considered in this report are electric power prices at the Mid-Columbia market hub, natural gas prices for the Sumas and Stanfield hubs, PSE loads, hydropower generation, wind generation, solar generation, and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

9.1. Development of Stochastic Model Inputs

A key goal in the stochastic model is to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is the correlation of variations in electric power prices with variations in natural gas prices contemporaneously or with a lag. Figure H.9 shows the key drivers we used to develop these stochastic inputs. Long-term economic conditions and energy markets determine the variability in the stochastic variables.

Figure H.9: Major Components of the Stochastic Modeling Process



Our stochastic model used the following process to simulate 310 futures of portfolio dispatch and cost:

1. Generate electric price draws. Like the deterministic wholesale price forecast, we used the AURORA model to simulate resource dispatch to meet demand and various system constraints. We vary regional demand, gas prices, and hydro and wind generation to create electric price draws. We use the price forecast for the Mid-C zone as the wholesale market price in the portfolio model.
2. Pull the electric and natural gas price draws generated in the first step into the hourly portfolio dispatch model.
3. Run the different portfolios drawn from the deterministic scenario and sensitivity portfolio through 310 draws that model varying power prices, gas prices, hydro, wind, and solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can observe how robust or risky the portfolio may be and where significant differences occur when we analyze risk.

9.2. Stochastic Electric Price Forecast

We use AURORA, a production cost model that utilizes electric market fundamentals to generate electric price draws. AURORA offers a Monte Carlo Risk capability that allows users to apply uncertainty to a selection of input variables. Users can add the variability of input assumptions into the model as an external data source, or AURORA can generate samples based on user statistics on a critical driver or input variable.

➔ Appendix G : Electric Price Models describes the methods and assumptions used to generate the stochastic electric price forecast and the simulation results.

9.3. Stochastic Portfolio Model

We use AURORA for stochastic portfolio modeling and apply a pre-defined iteration set to modify the input data in the model. We take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 310 draws that model varying power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant-forced outages. This section describes the model input assumptions we varied to generate the portfolio dispatch and cost.

9.4. Electric and Natural Gas Prices

The model packaged each completed set of power prices with gas prices and the assumed hydroelectric inputs when it generated the power price forecast. This bundle of power, gas prices, and hydroelectric conditions are input to the stochastic portfolio model. By packaging the power price, gas price, and hydroelectric year, the model preserved the relationships between gas prices and Mid-C prices and between hydro and power prices. Since there are only 90 draws generated from the stochastic electric price forecast, we sampled the electric price and natural gas uniformly to generate 310 draws.

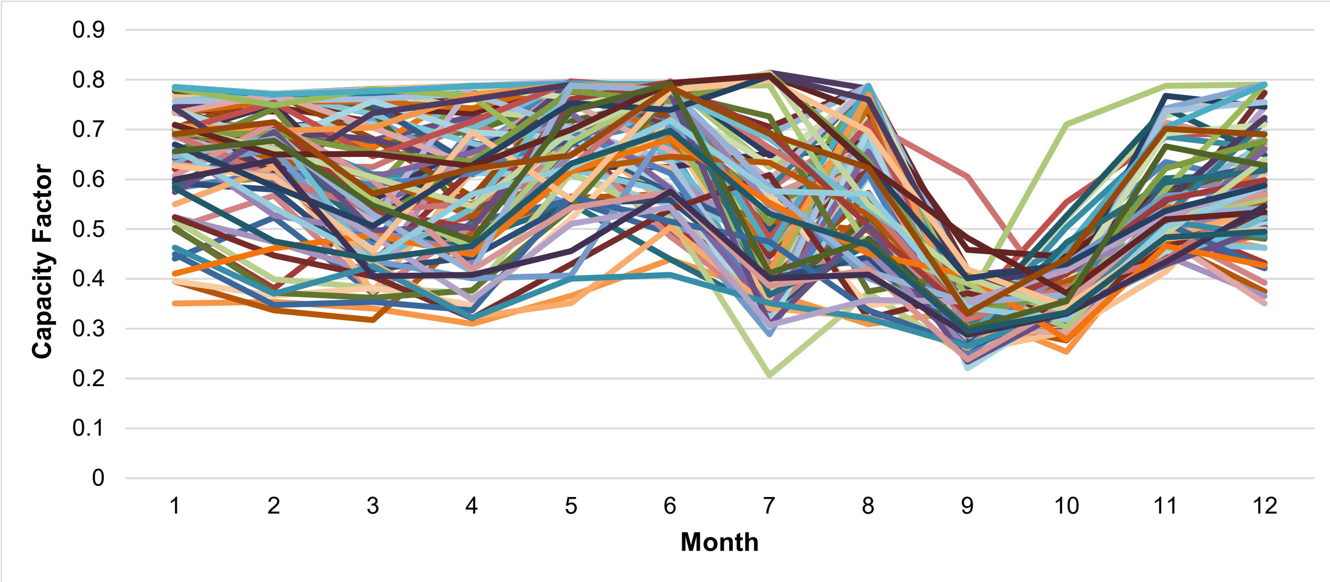
➔ Appendix G: Electric Price Models describes electric and natural gas price inputs.

9.5. Hydroelectric Variability

We use the same climate change hydroelectric data described in Appendix G: Electric Price Models for the stochastic electric price model. It is also the same hydroelectric data the Northwest Power and Conservation Council used for its 2021 Power Plan. Staying consistent with the other entities is essential since we all model the same hydropower projects.

Puget Sound Energy does not significantly depend on owned or contracted hydroelectric resources, so variations have a smaller effect on our ability to meet demand. The hydroelectric variations have a larger impact on the market for short-term purchases, as captured in the market risk assessment. The hydroelectric output of all 90 hydroelectric years is in Figure H.10. We uniformly sampled the 90 hydroelectric draws to generate 310 draws.

Figure H.10: Monthly Average Capacity Factor for 5 Mid-C Hydro Projects, 90 Draws



9.6. Electric Demand

The demand forecasts assume economic, demographic, temperature, electric vehicle, and model uncertainties to generate the set of stochastic electric demand forecasts.

The model derives the high and low monthly and annual demand forecasts from the distribution of these stochastic forecasts.

➔ Chapter Six: Demand Forecast and Appendix F: Demand Forecasting Models fully explain the stochastic demand forecasts.

9.7. Wind and Solar Variability

Consultant DNV generated wind and solar shapes to use in this Electric Report. On behalf of PSE, DNV used location information with the turbine model and power data as inputs to a stochastic model. The stochastic model generated 1,000 stochastic time series to represent the net capacity factor of a given wind or solar project for each site over the 22-year planning period. This methodology maintained daily, seasonal, and annual cycles from the original data. The stochastic model also maintained spatial coherency of weather, generation, and system load to preserve the relationships of projects across a region. DNV then randomly selected a sample of 250 annual hourly draws for each site, verified that the data represented the total distribution, and provided the data to PSE for modeling purposes.

We used the 250 wind and solar draws in the stochastic analysis. After the model selected each wind or solar draw once, it uniformly resampled the data to fill the remaining draws needed to generate 310 stochastic iterations.

➔ Appendix D: Generic Resource Alternatives contains a complete description of the wind and solar curves.

9.8. Forced Outage Rates

AURORA uses the frequency duration method, assigning each thermal plant a forced outage rate. This value is the percentage of hours in a year where the thermal plant cannot produce power due to unforeseen outages and equipment failure. This value does not include scheduled maintenance. In the stochastic modeling process, the model used the forced outage rate to randomly disable thermal generating plants, subject to the resource's minimum downtime and other maintenance characteristics. Over a stochastic iteration, the total time of the forced outage events will converge on the forced outage rate. This outage method option allows units to fail or return to service at any time step within the simulation, not just at the beginning of a month or a day. The frequency and duration method assumes units are either fully available or out of service.

9.9. Stochastic Portfolio Results

We tested the reference and preferred portfolios (sensitivity 11 B2) with the stochastic portfolio analysis.

➔ Stochastic results are in Chapter Eight: Electric Analysis, and the data is in Appendix I: Electric Analysis Inputs and Results.

10. PLEXOS Flexibility Analysis Model

Developed by Energy Exemplar, PLEXOS is an advanced production cost modeling tool we use for its capability to represent real-world, short-term operational decision cycles. This sophisticated platform allows us to appropriately model cost and reliability impacts associated with subhourly forecast uncertainty and renewable resource intermittency. Our flexibility analysis model provides for studies of interactions within our Balancing Authority Area (BAA), which designates the collection of electrical resources PSE controls and uses to balance supply and demand in real time. The BAA is different from our electric service area because some resources, such as wind and solar generators, could be physically located in the service area of another utility but are still considered part of PSE's BAA obligations. Our flexibility analysis model provides critical insights into PSE’s capabilities to integrate renewable resources into our BAA and understand the benefits of additional flexible generation resources beyond capacity and energy value.

To appropriately reflect conditions on a subhourly basis, we must develop the PLEXOS model to reflect cycle-specific decisions and recourse actions carefully. We must make some decisions based on their decision cycle, such as a day-ahead block transaction at Mid-C occurring in a day-ahead model. However, the energy schedule of generators in a day-ahead model is generally not required to remain constant across the studied day. Modeling these decisions, which we must fix in models of later decision cycles and allowing recourse actions to occur as uncertainty resolves, such as peaker commitments, are critical to reflect the subhourly flexibility of PSE's system accurately. Currently, our flexibility analysis model studies scheduled system impacts down to 15-minute segments.

The starting point of this analysis is a base portfolio comprised of PSE's existing resources scheduled to be operational through 2029, plus sufficient firm capacity, so the model is not resource inadequate, on an hourly timeframe, based on the results of the Resource Adequacy study. However, the model fixes firm capacity hourly, so it does not affect the analysis of subhourly flexibility. In this way, the model design prevents insufficient capacity or energy from affecting the results, with a resource-deficient starting position and no knowledge of the portfolio in 2029. When the model adds new resources, the firm capacity available to make the hourly model resource sufficient is adjusted down, so the total peak capacity in the model matches the peak need in 2029.

We ran the base case, what is presently known about our portfolio through the year 2029, and pivot cases, which are each the base case portfolio plus the addition of one new resource, through the simulation phases. The model then calculates the subhourly dispatch cost associated with each case. A difference in the subhourly costs of each pivot case against the base case is the flexibility benefit associated with the resource decision. This benefit is the cost difference of the study year divided by resource nameplate rating and determines a benefit per year ($/kW-year). As part of the IRP's decision framework, our flexibility analysis model uses subhourly benefits associated with new resource pivots calculated and made available to the LTCE model in AURORA by applying the flexibility benefit as a fixed benefit per year.

10.1. PLEXOS Simulation Phases

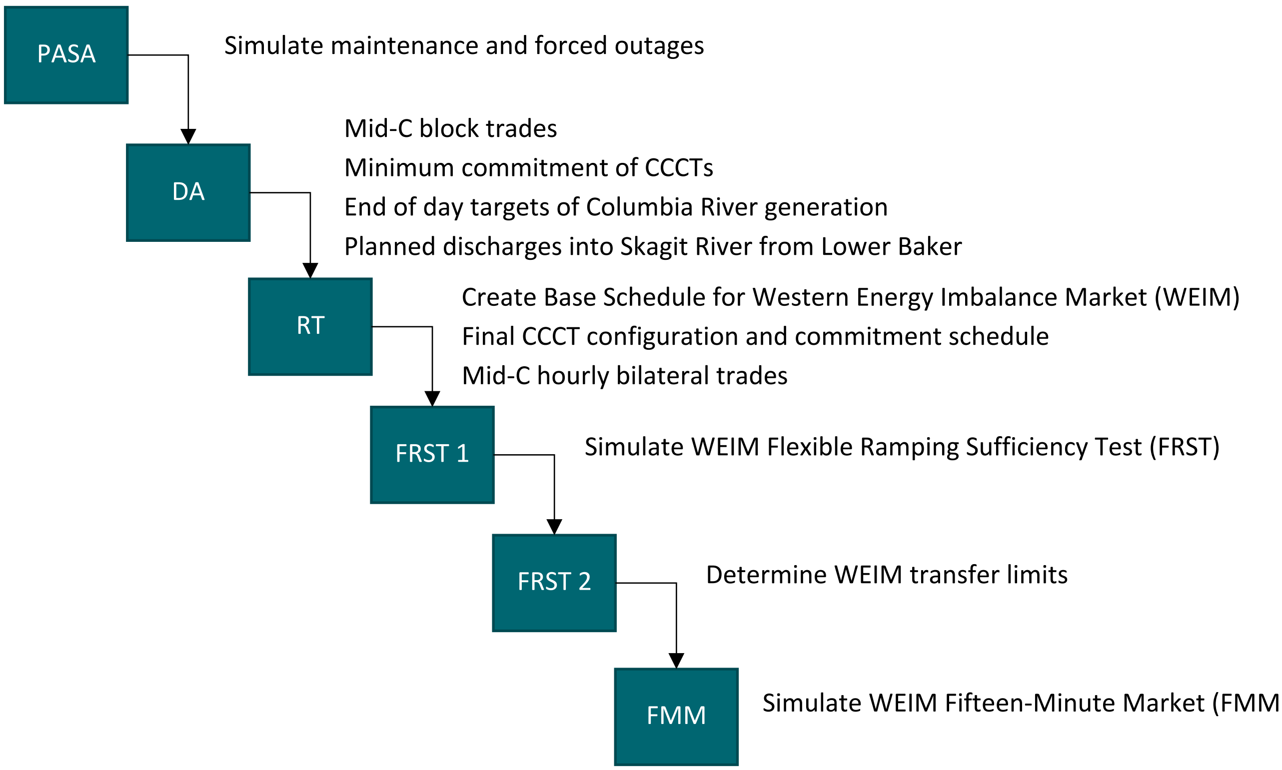
We used a multi-stage simulation approach in PLEXOS. Each stage runs separately but in sequence, so the model appropriately reflects critical decisions from earlier cycles in later decision cycles.

1. First, a model cycle in PLEXOS called Projected Assessment of System Adequacy (PASA) incorporates scheduled maintenance and random outages. It simulates the availability of the generation units with the given forced outage rates and scheduled maintenance information.
2. Then, the day-ahead stage determines a minimum plant commitment schedule for PSE's combined-cycle combustion turbine (CCCT) units, end-of-day targets for our Columbia River hydroelectric resources, planned discharges into the Skagit River from Lower Baker (Lake Shannon), and block trades for peak and off-peak hours at the Mid-C market.
3. Next, an hourly bilateral model performs finer-granularity trades at the Mid-C market and establishes the final CCCT schedule of run hours and combustion turbine (CT) commitment choices. This stage simulates a Base Schedule submitted to the California Independent System Operator's (CAISO's) Western Energy Imbalance Market (WEIM). As such, peaking units needed to balance hourly must run for the entire binding trade hour, while peaking units not committed are free to be committed by the WEIM. Additionally, as part of the Base Schedule submission, this model cycle selects operating reserves that CAISO cannot dispatch into (Spin and Non-Spin) and Regulation Up and Regulation Down, which CAISO terms Available Balancing Capacity (ABC) and can use sparingly.
4. Following the model, which simulates the creation of a Base Schedule, two 15-minute resolution models are used to perform the Flexible Ramping Sufficiency Tests (FRSTs) that CAISO uses to determine if WEIM participants have sufficient flexibility. The first model (Part 1) performs the test by simulating procurement of

the two Flexible Ramping Products (FRPs), FRP Up and FRP Down, from our system in isolation. If PLEXOS cannot procure enough FRP in one direction and/or the other, access to the WEIM market is limited to that of the previous Fifteen Minute Market (FMM) schedule in the direction(s) of test failure. The second model (Part 2) simulates WEIM interactions in the absence of any transfer limitation to determine what the transfer limits should be.

5. Finally, the model simulates FMM with all the upstream binding model decisions and FRST results.

Figure H.11: PLEXOS Simulation Phases



10.2. PLEXOS Model Inputs

We calibrated the inputs to the PLEXOS model to be as close to AURORA's input as possible for model framework consistency.

10.2.1. Contingency Reserve

Bal-002-WECC-1 requires balancing authorities to carry reserves for every hour: three percent of online generating resources and three percent of load to meet contingency obligations.

10.2.2. Balancing Reserve

Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same short-term, forced-outage reliability benefit as contingency reserves triggered by specific criteria. Balancing reserves are resources that can ramp up and down quickly as loads and resources fluctuate within a given operating hour.

E3 assessed PSE's balancing reserve requirements based on CAISO's flexible ramping product calculations. The results depend heavily on the mean average percent error (MAPE) of the hour-ahead forecasts vs. real-time values for load, wind, and solar generation.

➔ Further discussion of reserves is in Chapter Seven: Resource Adequacy Analysis.

10.2.3. Natural Gas Prices

We used a combination of forward market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie for natural gas prices. The natural gas price forecast is an input to the AURORA electric price modeling and portfolio model.

➔ The natural gas price inputs are in Chapter Five: Key Analytical Assumptions.

10.2.4. Electric Prices

We developed the electric price forecast for the Mid-C day-ahead and hourly trades using AURORA and input to PLEXOS. We determined subhourly prices by creating imbalance supply and demand stacks from the AURORA price forecast model's solutions for Pacific Northwest resources. This methodology reflects the limited market depth subhourly and prevents PLEXOS from overestimating opportunities in imports or exports.

10.2.5. Demand Forecast

We added PSE's demand forecast to PLEXOS using the monthly energy need (MWh) and peak need (MW). We layered on historical forecast errors from CAISO's forecasting of PSE's load in 2021 and 2022 to develop day-ahead, hour-ahead, and 15-minute forecasts.

➔ A description of our demand forecast is in Chapter Six: Demand Forecast.

10.3. Flexibility Benefit

To estimate the flexibility benefit of incremental resources, PLEXOS first runs the base case, which contains only PSE's current resource portfolio, and the firm capacity necessary for the model to be resource sufficient hourly. Then, we rerun PLEXOS with one new generic resource, adjusting the firm capacity down based on the new generic resource's peak capacity contribution. We then compare the subhourly production cost result of the case with the base portfolio to the production cost of the case with the additional resource.

We ensure sufficient hourly capacity and energy by providing firm capacity up to the peak need identified in the resource adequacy study. However, we must do more work to ensure that subhourly flexibility benefits do not double-count benefits by inadvertently including traces of capacity or energy value.

Current processes in AURORA step down to hourly resolution. In the current PLEXOS framework, to perform the flexibility analysis, this reflects the hourly bilateral model described. This model simulates creating and submitting a Base Schedule to the WEIM, where charges and credits are assessed based on movements away from the Base Schedule.

In the WEIM, the load buys imbalance energy when demand is above the Base Schedule hourly load forecast and sells imbalance energy when demand is below the Base Schedule hourly load forecast. This transaction occurs because of the resolved load forecast error that refines and improves with each decision cycle. Energy generators in the WEIM sell imbalance energy when their dispatch schedule exceeds the Base Schedule energy forecast and buy imbalance energy when their dispatch schedule is below the Base Schedule energy forecast. Generators may do this by economically optimizing interactions in the WEIM and taking advantage of opportunities to the changing load forecast and resource outages.

In order to attach subhourly values to hourly decision models in AURORA, we must first determine the net direct generation cost difference as the PLEXOS model moves from its hourly bilateral cycle to the WEIM FMM cycle. For example, if the model forecasts a gas generator to dispatch at 100 MW for some operating hour (100 MWh of energy) of an hourly cycle and then schedules it to generate 50 MWh total in the FMM cycle, there is a reduction in direct generation expenses associated with producing 50 MWh less energy. Each cycle's total direct generation cost is the sum of start-up costs, fuel costs of energy dispatch, variable operations and maintenance costs, and direct emissions costs.

The model then calculates the net cost of the WEIM energy products for scheduled movements associated with the load and generators. Finally, it assesses congestion rent to reflect the revenue we receive from the price separation between PSE's system and the WEIM. When dynamic transfers are binding along the EIM Transfer System Resource (ETSR) ties between PSE and neighboring WEIM participants, price separation is likely to occur, resulting in congestion revenue associated with the transfer. Current WEIM rules establish that any ETSR not directly connected to the CAISO full market footprint has revenues split equally among the interconnecting systems. As such, the model calculates one-half of the congestion revenue returns to PSE for this flexibility benefit calculation.

The flexibility benefit is the difference between the pivot case's and the base case's subhourly costs. This value as the cost difference in a year, divided by the nameplate of the pivot resource, is used to determine the flexibility benefit in $/kW-year.

The flexibility benefit calculation process is summarized as follows:

1. Run the base case, all models from day-ahead to FMM.
2. Run the pivot case, all models from day-ahead to FMM.

3. Calculate the subhourly cost of the base case and pivot cases:

    a. Subhourly cost =
       Net direct generation cost difference
       + net cost of imbalance energy market products for PSE BAA load
       + net cost of imbalance energy generation products by PSE merchant
       + congestion revenue

4. Calculate the difference between the subhourly costs between the pivot case and base case.

5. Divide by nameplate rating to determine the nominal flexibility benefit in $/kW-year.

11. Avoided Costs

Consistent with WAC 480-100-620(13),[7] the estimated avoided costs in this section provide only general information about the costs of new power supplies, and we only used them for planning purposes. This section includes estimated capacity costs consistent with the resource plan forecast, transmission and distribution deferred costs, greenhouse gas emission costs, and the cost of energy.

11.1. Capacity

Avoided capacity costs are directly related to avoiding the acquisition of new capacity resources. The timing and cost of avoided capacity resources are tied directly to the resource plan. This value represents the average cost of capacity additions (or average incremental costs), not marginal costs.

➔ The indicative avoided capacity resource costs are in Appendix I: Electric Analysis Inputs and Results.

The costs are net capacity costs — we deducted the energy or other resource values using the Mid Scenario results. For example, frame peakers can dispatch into the market when the cost of running the plant is less than market, which creates a margin that flows back to reduce customers' rates.

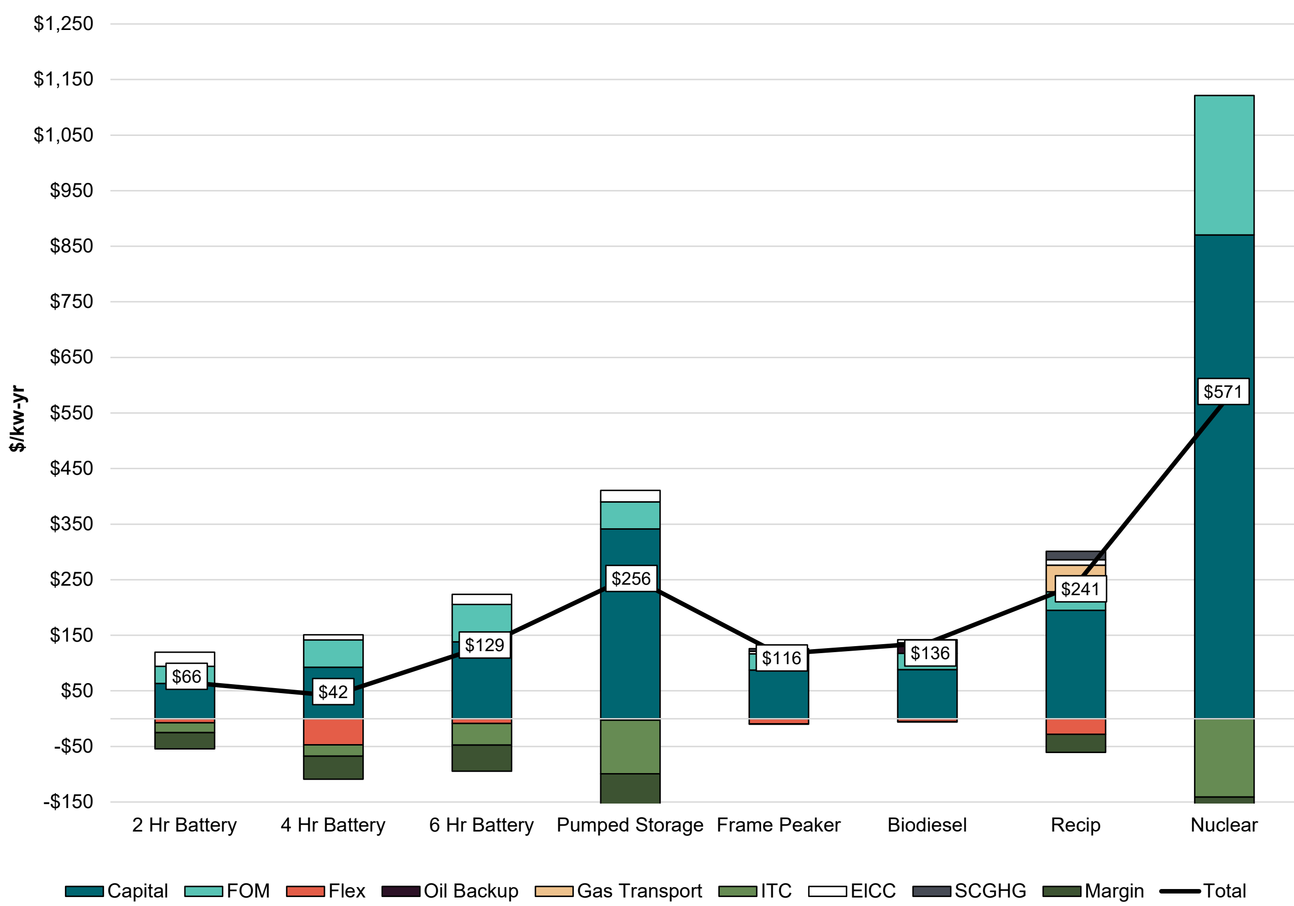
In addition to the avoided capacity cost expressed in $/kW-yr, the capacity credit of different resources needs to be specified. After specifying the annual avoided capacity resource costs by year, the avoided capacity costs include indicative adjustments to peak capacity value from this report's effective load carrying capability (ELCC) analysis.

The ELCC for a firm dispatchable resource would be 100 percent, but different intermittent resources have different peak capacity contributions. The capacity contributions used here are consistent with those described in Chapter Seven: Resource Adequacy. These results reflect the first tranche of ELCC, the first 1000 MW added to the system.

[7] WAC 480-100-620

As we add more resources to the system, the resources provide less peak capacity benefit. Figure H.12 shows the levelized cost of capacity (LCOC) compared across capacity resources.

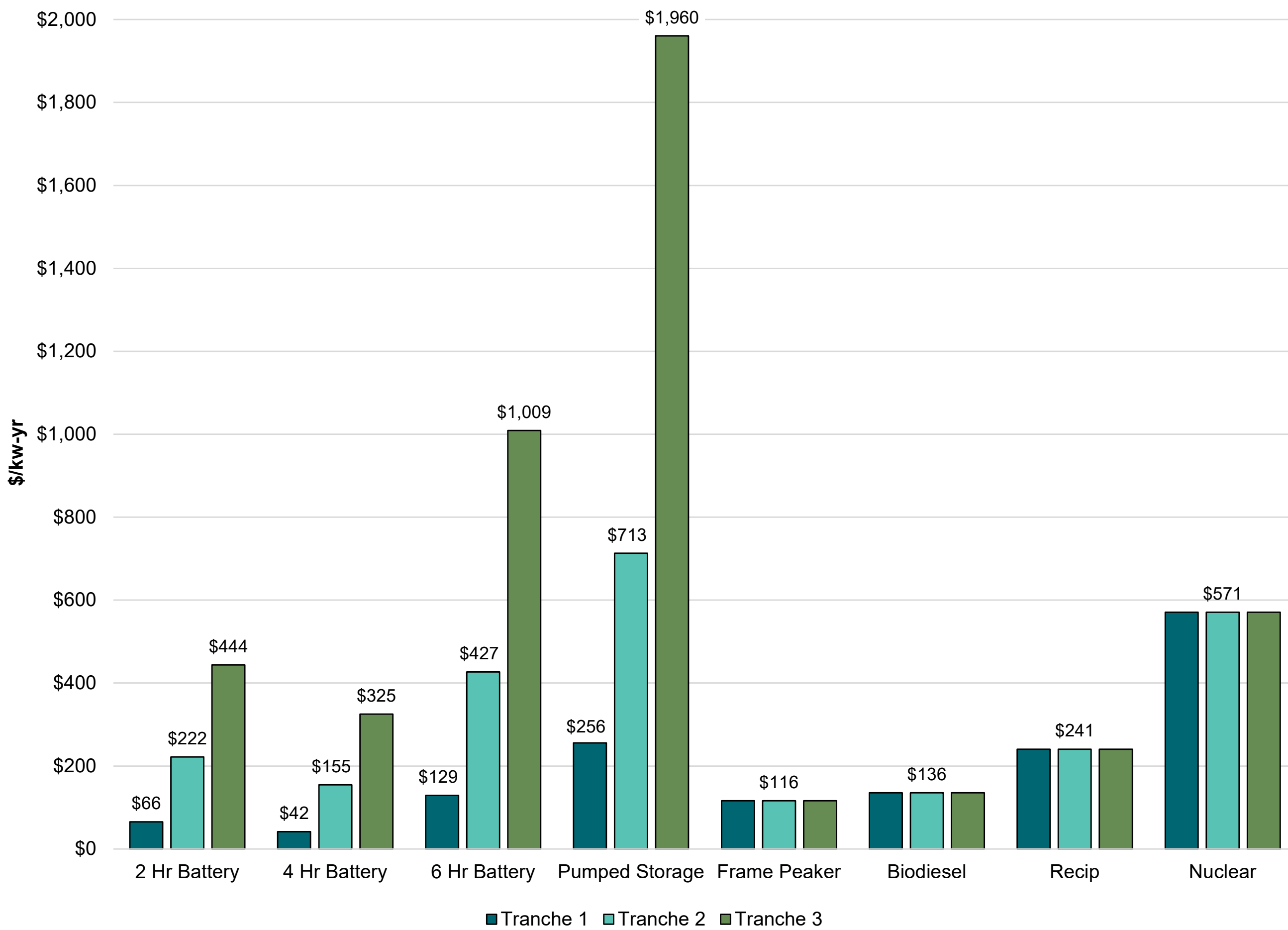
Figure H.12: Net Cost of Capacity in the Reference Portfolio



11.1.1. Saturation Curves

As we add more storage to the system with limited duration, it has less of an impact on meeting peak demand. Initially, storage can clip peaks with the shorter duration. As we add more storage to the system, the peak will flatten and require longer-duration resources to meet the peak. Figure H.13 illustrates the levelized cost impact of the tranches as described in Chapter Seven: Resource Adequacy Analysis. For example, the cost of peak capacity for a Lithium-ion 2-hour battery in Tranche 1 is $66/kW-year, and Tranche 3 is $444/kW-year.

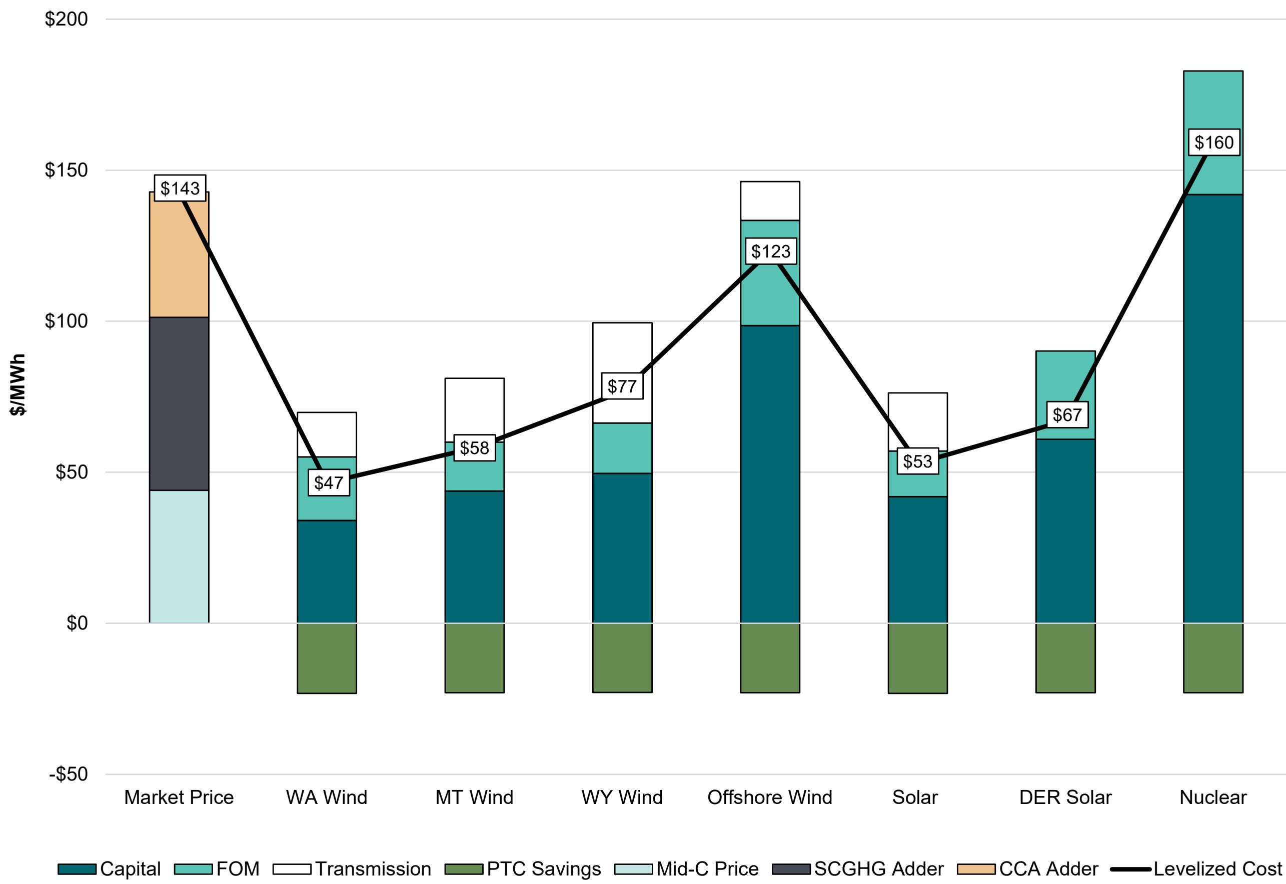
Figure H.13: Impact of Saturation Curves



11.2. Levelized Cost of Energy

We evaluated the levelized costs of energy from renewable resources based on assumptions in the reference portfolio. Renewable resource costs benefit from increased tax credits as a result of the Inflation Reduction Act. We can see the benefits in the cost component chart, Figure H.14, below the x-axis. The total energy costs do not include the peak capacity contribution to the portfolio. For example, Washington wind is the lowest cost in terms of energy because of reduced transmission costs compared to Montana and Wyoming wind. However, Montana and Wyoming wind have significantly higher peak capacity values than Pacific Northwest wind. Eastern Washington utility-scale solar is competitive in terms of energy but provides minimal peak capacity benefit. Figure H.14 illustrates the levelized costs of renewable resources to meet CETA.

Figure H.14: Levelized Cost of Energy



11.2.1. Conservation

We use bundles as the supply curve to determine the cost-effective demand-side management measures to reduce load and peak capacity. The following charts provide the cumulative cost impact as one moves up the supply curve. Figure H.15 shows an energy perspective, and Figure H.16 a capacity perspective.

Figure H.15: Conservation Cumulative Cost of Energy by Bundle

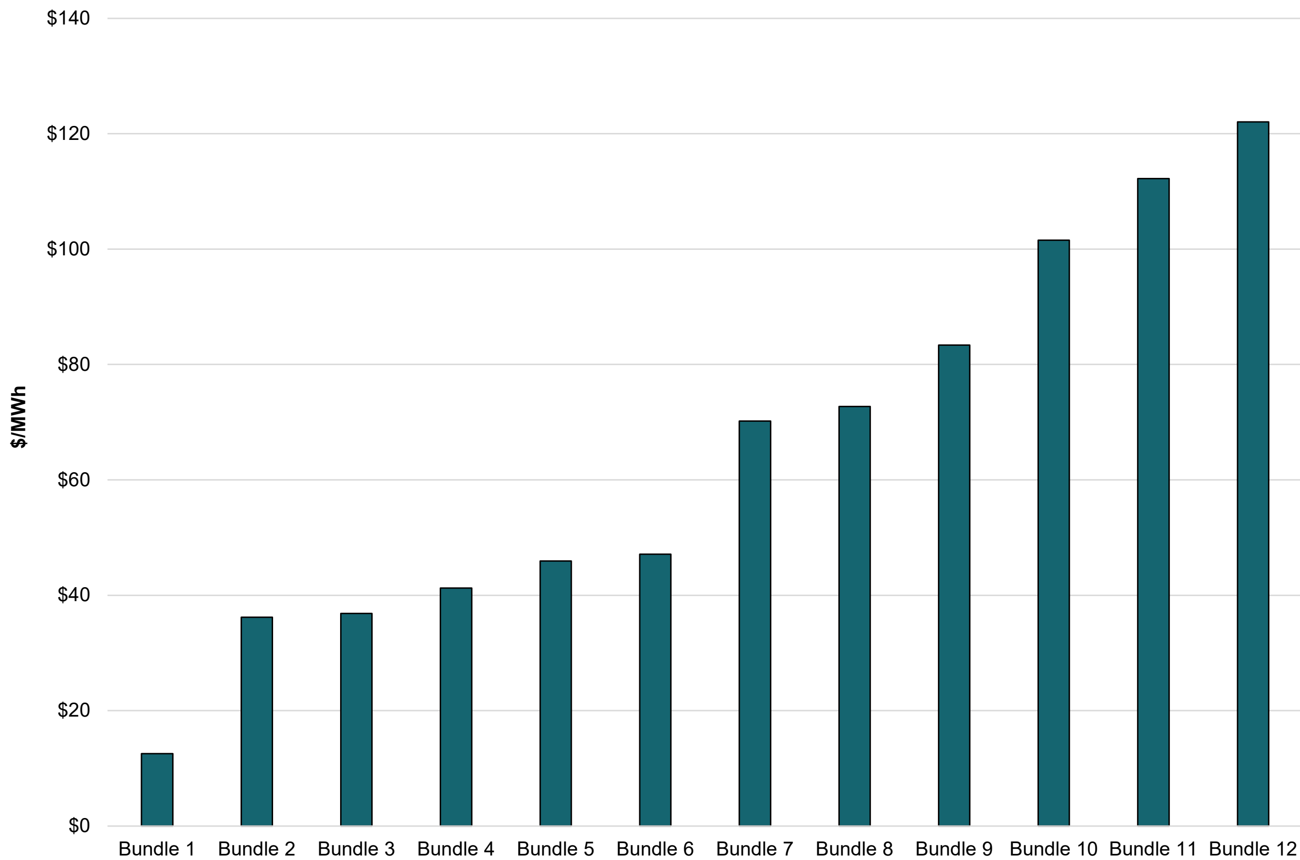
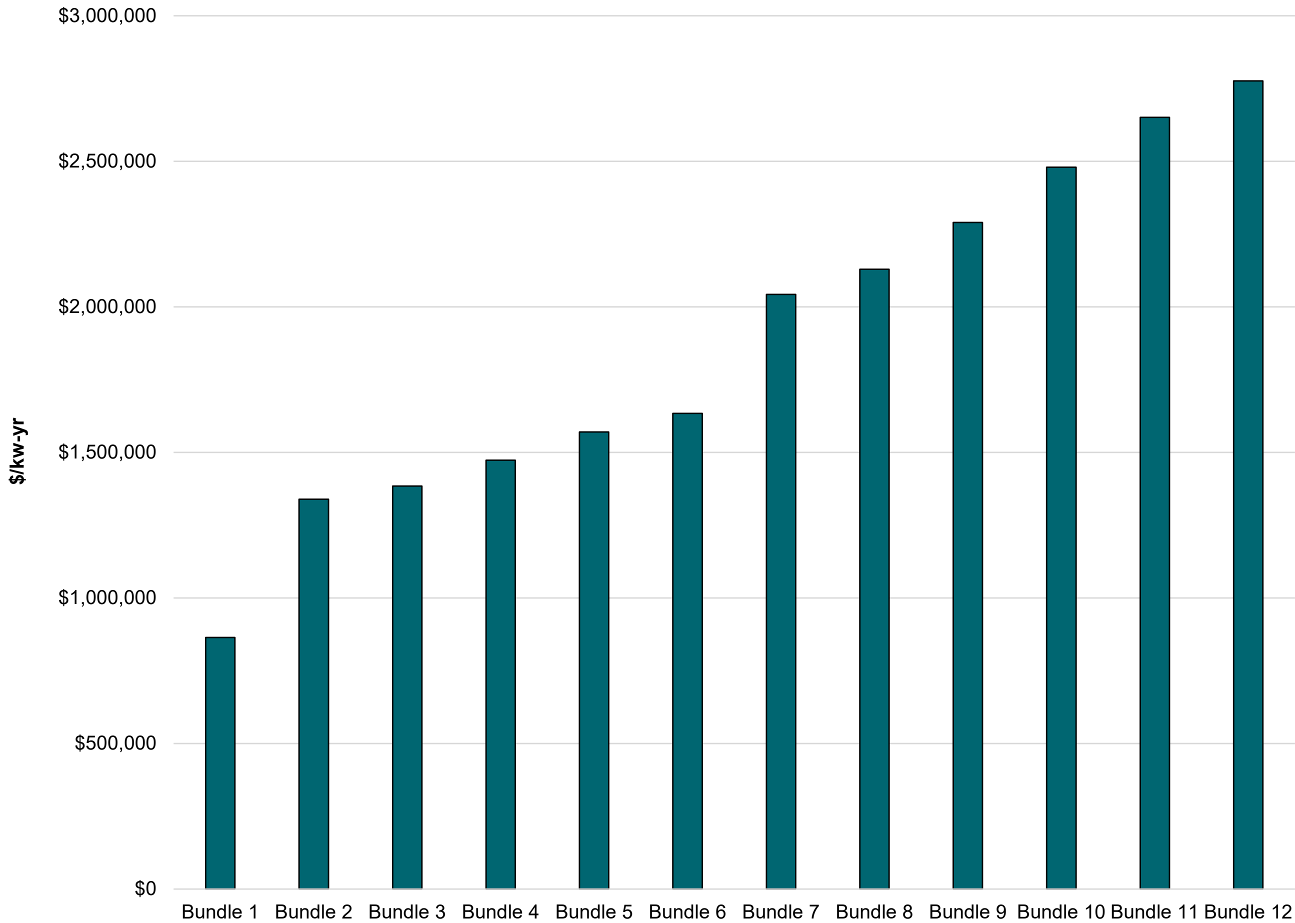


Figure H.16: Conservation Cumulative Cost of Capacity by Bundle



11.3. Deferred Transmission and Distribution Cost

The estimated avoided T&D cost is $74.70/kW-year. See the Transmission and Distribution Cost in the Financial Assumptions section of this appendix.

11.4. Avoided Costs of Greenhouse Gas Emission

This 2023 Electric Report includes modeling the SCGHG and an allowance price for the Climate Commitment Act. The emission rate for unspecified market purchases, as outlined in RCW 19.405.070, is 0.437 metric tons of CO2/MWh. Therefore, the carbon price for unspecified market purchases is the combined total of the SCGHG and the CCA GHG emission costs. See Table H.5.

Table H.5: Avoided Carbon Costs Unspecified Market Purchases $/MWh

Year	SCGHG ($/MWh)	CCA ($/MWh)	Total ($/MWh)
2024	35.43	25.31	60.74
2025	36.50	27.75	64.25
2026	37.04	28.16	65.20
2027	37.58	26.16	63.74
2028	38.11	26.73	64.84
2029	38.65	28.90	67.55
2030	39.19	27.12	66.30
2031	39.72	30.39	70.12
2032	40.26	34.06	74.32
2033	40.80	38.18	78.98
2034	41.33	42.79	84.12
2035	41.87	47.96	89.83
2036	42.41	50.45	92.85
2037	43.48	53.06	96.54
2038	44.02	55.81	99.83
2039	44.55	58.71	103.26
2040	45.09	61.75	106.84

Year	SCGHG ($/MWh)	CCA ($/MWh)	Total ($/MWh)
2041	45.63	64.95	110.58
2042	46.17	68.32	114.49
2043	46.70	71.86	118.57
2044	47.24	75.59	122.83
2045	47.78	79.51	127.29

11.5. Avoided Cost of Capacity

In Chapter Three, we documented our preferred portfolio for the 2023 Electric Report and explained why we added different resources. The first resource we added to the portfolio for capacity needs is the biodiesel peaker in 2024 at $136/kW-year. Even though we added other resources to the portfolio in the early years, we added them for different reasons. For example, distributed energy resources (DERs) such as batteries make lower peak capacity contributions and have higher costs. However, DERs play an essential role in balancing utility-scale renewable investments and transmission constraints while meeting local distribution system needs and improving customer benefits, which is why we used the frame peaker as the avoided cost of capacity.

Table H.6: shows the avoided capacity costs we estimated in this 2023 Electric Report. Under WAC 480-106-040(b)(ii),[8] the 2023 report's first capacity addition in 2024 is a biodiesel peaker, the basis for the peak capacity avoided cost. The results reflect the cost of the biodiesel peaker net of the ELCC for the biodiesel peaker, wind, and solar.

Table H.6: 2023 Avoided Capacity Costs (Nominal $/kW-yr)

Year	Capacity Resource Addition	(a) Levelized Net $/kW-year Delivered to PSE	(c)=(a) Firm Resource ($)	(d)=(a)*0.13 Wind Resource ELCC=13% ($)	(e)=(a)*0.04 Solar Resource ELCC=4% ($)
2024	Baseload Resource	135.69	135.69	17.64	5.43
2025	Baseload Resource	135.69	135.69	17.64	5.43
2026	Baseload Resource	135.69	135.69	17.64	5.43
2027	Baseload Resource	135.69	135.69	17.64	5.43
2028	Baseload Resource	135.69	135.69	17.64	5.43
2029	Baseload Resource	135.69	135.69	17.64	5.43

[8] WAC 480-106-040

Year	Capacity Resource Addition	(a) Levelized Net $/kW-year Delivered to PSE	(c)=(a) Firm Resource ($)	(d)=(a)*0.13 Wind Resource ELCC=13% ($)	(e)=(a)*0.04 Solar Resource ELCC=4% ($)
2030	Baseload Resource	135.69	135.69	17.64	5.43
2031	Baseload Resource	135.69	135.69	17.64	5.43
2032	Baseload Resource	135.69	135.69	17.64	5.43
2033	Baseload Resource	135.69	135.69	17.64	5.43
2034	Baseload Resource	135.69	135.69	17.64	5.43
2035	Baseload Resource	135.69	135.69	17.64	5.43
2036	Baseload Resource	135.69	135.69	17.64	5.43
2037	Baseload Resource	135.69	135.69	17.64	5.43
2038	Baseload Resource	135.69	135.69	17.64	5.43
2039	Baseload Resource	135.69	135.69	17.64	5.43
2040	Baseload Resource	135.69	135.69	17.64	5.43
2041	Baseload Resource	135.69	135.69	17.64	5.43
2042	Baseload Resource	135.69	135.69	17.64	5.43
2043	Baseload Resource	135.69	135.69	17.64	5.43
2044	Baseload Resource	135.69	135.69	17.64	5.43
2045	Baseload Resource	135.69	135.69	17.64	5.43
2046	Baseload Resource	135.69	135.69	17.64	5.43
2047	Baseload Resource	135.69	135.69	17.64	5.43

11.6. Schedule of Estimated Avoided Costs for PURPA

This schedule of estimated avoided costs, as prescribed in WAC 480-106-040,[8] identifies the estimated avoided costs for qualifying facilities and did not provide a guaranteed contract price for electricity. The schedule only identifies general information to potential respondents about the avoided costs. The schedule of estimated avoided costs includes table H.7.

Table H.7: Schedule of Estimated Avoided Costs

Year	Jan ($/MWh)	Feb ($/MWh)	Mar ($/MWh)	Apr ($/MWh)	May ($/MWh)	Jun ($/MWh)	Jul ($/MWh)	Aug ($/MWh)	Sept ($/MWh)	Oct ($/MWh)	Nov ($/MWh)	Dec ($/MWh)	Avg. ($/MWh)
2024	39.63	34.62	28.06	25.48	18.80	25.90	41.99	39.52	43.83	37.21	37.83	42.11	34.60
2025	36.53	35.25	28.43	25.91	18.10	25.72	43.40	39.52	45.69	39.52	38.58	44.07	35.07
2026	40.56	37.51	28.65	26.60	19.30	27.72	48.36	43.13	48.76	42.21	40.09	47.36	37.54
2027	44.76	43.26	33.36	29.87	20.67	32.23	54.24	48.89	54.25	46.43	45.05	50.92	42.00
2028	48.81	43.09	33.96	30.33	22.08	32.79	55.96	51.51	54.65	47.06	46.28	54.19	43.42
2029	47.16	41.67	31.04	29.90	21.21	30.97	56.35	53.98	59.35	49.82	47.93	53.70	43.62
2030	47.25	41.25	28.86	27.96	21.28	30.19	57.33	53.89	58.43	49.54	47.17	53.66	43.11
2031	43.73	41.48	28.51	30.42	18.73	30.98	58.78	54.89	59.99	50.06	47.64	54.63	43.35
2032	45.70	40.25	27.30	27.92	17.50	32.21	59.80	56.79	63.91	51.87	48.94	56.06	44.05
2033	45.97	42.63	28.01	27.41	17.08	33.43	66.18	62.35	62.92	54.36	50.75	61.17	46.08
2034	44.72	39.55	29.17	29.93	18.57	34.77	69.13	60.31	65.16	57.12	52.61	60.22	46.84
2035	48.13	42.67	29.00	29.97	18.76	32.11	73.47	67.31	74.18	59.98	54.95	63.40	49.57
2036	51.27	40.68	27.93	28.88	17.96	33.34	78.64	69.53	74.86	58.73	53.78	64.03	50.05
2037	47.53	43.33	31.94	29.07	15.61	34.48	80.66	72.61	79.31	59.44	55.46	66.95	51.45
2038	48.74	39.85	27.70	28.54	16.53	34.02	84.20	70.73	80.97	63.14	56.52	70.80	51.93
2039	51.29	43.69	28.06	28.31	16.45	39.28	86.83	74.81	80.62	62.83	59.70	71.77	53.74
2040	49.87	40.71	29.20	28.94	18.16	40.70	89.73	75.98	82.77	66.41	56.38	73.33	54.45
2041	58.79	45.67	28.21	29.94	14.90	35.20	92.56	83.56	89.62	66.93	63.05	75.47	57.11
2042	59.15	44.92	26.89	29.51	14.59	38.35	101.79	92.74	91.72	66.90	61.39	81.39	59.27
2043	59.81	44.28	30.51	28.65	15.73	42.72	107.66	89.90	96.07	67.15	64.72	84.67	61.16

ELECTRIC ANALYSIS INPUTS AND RESULTS

APPENDIX I

PSE PUGET SOUND ENERGY

Contents

1. Introduction 1

2. Modeling Inputs 2

2.1. Aurora Portfolio Model Inputs 2

2.2. Generic Resources 3

2.3. Carbon Dioxide Prices 3

2.4. AURORA Generic Wind and Solar Shapes 4

3. Modeling Outputs 4

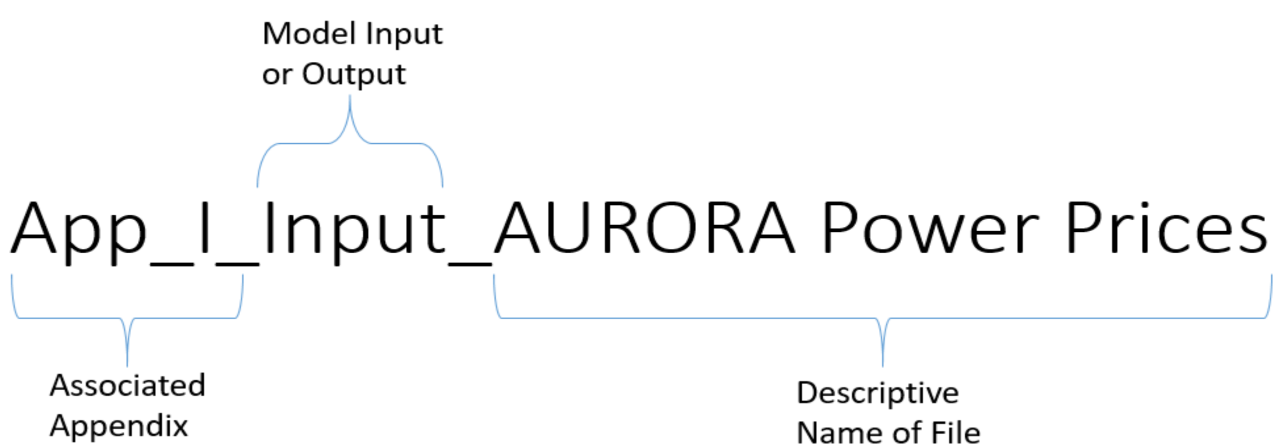
3.1. AURORA 4

3.2. PLEXOS 5

1. Introduction

For the 2023 Electric Progress Report (2023 Electric Report), Puget Sound Energy (PSE) is providing Microsoft Excel files containing input and output data in separate files instead of data tables directly in the report. Direct access to the data provides usable files for interested parties as opposed to static tables in a PDF format. Technical limitations on how PSE is able to submit files to the Washington Utility Transportation Commission (Commission) and host files online for public access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure I.1 provides an example of how the provided files will be named. Each Excel file also contains a Read Me sheet with specific details related to the data contained in that file.

Figure I.1: Naming Conventions for Appendix I Files



2. Modeling Inputs

The first section of this appendix highlights the inputs to the modeling process. These inputs are split out into subsections categorically, including a group of inputs that are directly linked to the AURORA model and other groups that have background information on more complex inputs such as generic resource costs or shaping of wind and solar resources.

2.1. Aurora Portfolio Model Inputs

The AURORA Long Term Capacity Expansion (LTCE) Portfolio Model files contain the data used in AURORA that PSE is able to share publicly. This includes generic resource assumptions, financial assumptions and specific settings used in AURORA. Table I.1 provides a list of AURORA input files provided in this Report.

Table I.1: AURORA Portfolio Model Input File Names

File Names	Description
App_I_Input_AURORA LTCE Inputs	Contains inputs for the AURORA LTCE model, including generic resource assumptions and modeling parameters. Existing resource information is not included.
App_I_Input_AURORA Power Prices	Contains the results of the hourly power price model, which is used as the power price inputs for other models.
App_I_Input_Electric Demand Forecast	Contains the annual summary of PSE's demand forecasts used in the 2023 Electric Report.
App_I_Input_Climate Change Data	Contains the climate change data that is an input to the electric demand forecast

LTCE Inputs: This file contains the non-hourly inputs into the AURORA LTCE model, including generic resource assumptions and other modeling parameters. Confidential information regarding PSE's existing resources and other assets has been removed. All dollar values that are entered into AURORA are in 2020 dollars.

➔ More documentation of the AURORA modeling process can be found in Chapter Eight: Electric Analysis and Appendix G: Electric Price Models.

Power Prices: This workbook contains all of the hourly power price data developed for this IRP. For sensitivities that change the hourly dispatch, a new hourly price forecast is required. The AURORA power price forecast is run using the conditions of the scenario or sensitivity. Yearly and monthly prices are averages of those periods, and all prices are in $/MWh.

➔ More information about power prices can be found in Chapter Five: Key Analytical Assumptions.

Demand Forecast: This workbook contains the data for the electric system demand forecast. There are two tabs, one for electric demand in aMW and another for system peak in MW. These tabs break down the base scenario, EV demand and other similar adjustments.

Climate Change Data: This is a secondary input, meaning it is an input to an AURORA input. This workbook contains the data and calculations for the climate change models that are an input to the electric demand forecast. It contains all the adjusted temperatures from the different models and tabs showing how those were implemented into the load forecasting process.

➔ More information about the demand forecast can be found in Chapter Six: Demand Forecast.

2.2. Generic Resources

This workbook provides a summary of cost assumptions and details on cost adjustments applied to the Generic Resources PSE will consider in the 2023 Electric Report portfolio planning process. The majority of cost assumptions are sourced from the 2022 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) cost report.

Table I.2: Generic Resources File Name

File Name	Description
App_I_Input_Generic Resources	Contains cost assumptions and adjustments used for the generic resources modelled in the 2023 Electric Report.

Generic Resources: This workbook details the various assumptions passed into the model for generic resources. These assumptions include operating life, capital costs, operation and maintenance (O&M) costs, spur line costs, among many.

2.3. Carbon Dioxide Prices

The carbon dioxide (CO_2) Prices file contains the calculations of the Social Cost of Greenhouse Gases (SCGHG) and Climate Commitment Act (CCA) used during the 2023 Electric Report. Figure I.3 provides the name of this file.

Table I.3: CO_2 Prices File Name

File Name	Description
App I_Input_Carbon Prices	Contains the calculations for the SCGHG and CCA values used in the 2023 Electric Report.

Carbon Prices: This workbook contains PSE's calculations for converting the SCGHG and CCA prices into a format compatible with AURORA. This includes the base SCGHG calculation and the H.R. 763 SCGHG calculation.

2.4. AURORA Generic Wind and Solar Shapes

The generic wind and solar capacity factor shapes used to model utility-scale renewable resources all have the same format, which is described below. Figure I.4 provides the file names of these datasets.

Table I.4: Generic Wind and Solar Shape File Names

File Names	Description
App_I_Input_Wind and Solar Shapes	This dataset contains monthly shapes for all solar and wind resources modeled in the 2023 Electric Report

Each tab within the workbook details monthly shaping for a given resource. Resource shapes in the form of monthly capacity factors are provided for existing PSE resources as well as new generic resources modelled. The months run across the top with the Sample ID going vertically, denoting which stochastic simulation it corresponds to. The notes column shows which sample was used in the deterministic portfolio modelling. Each resource has the seasonal Net Capacity Factor (NCF) plotted on the left.

Table I.5: Naming Conventions for the Tabs in Wind and Solar Shapes File

Name	Meaning
Stochastic	This dataset contains 250 capacity factor profiles of the resource location for use in the stochastic modeling process.
Deterministic	This dataset contains the representative capacity factor profile of the resource location that was used in the deterministic portfolio model. This is called out in the notes section.

➔ See Appendix D: Generic Resources for a detailed explanation of the generic renewable resource generation profiles.

3. Modeling Outputs

This section of the appendix details the output files provided from both the AURORA and PLEXOS models. The files from AURORA include information on the fundamental attributes of the various portfolios modeled such as cost, builds, emissions and customer benefit values, as well as information on levelized resource costs and summarized results of the stochastic analysis. The PLEXOS output file presents the flexibility benefits and violations associated with the flexibility analysis model.

3.1. AURORA

The AURORA output files contain the AURORA output data that PSE is able to share publicly. Figure I.6 provides the file names of these datasets.

Table I.6: AURORA Output Files

File Names	Description
App_I_Output_Portfolio Output Summary	Contains an overview of the output data from the AURORA LTCE and hourly dispatch models.
App_I_Output_Portfolio Benefit Analysis	Contains the data and calculations which inform the portfolio benefit analysis for all the portfolios.
App_I_Output_Levelized Resource Costs	Contains the calculations of the levelized costs of new resources in the 2023 report.
App_I_Output_Stochastic Modeling Results	Contains an overview of the results from the AURORA stochastic model.

Portfolio Output Summary: This workbook contains an overview of the output data from each electric portfolio modeled. The portfolio build data, emissions, annual costs and overall portfolio costs is some of the key information included.

Portfolio Benefit Analysis: This workbook provides a tool to measure potential equity-related benefits to customers within the different portfolio options modeled in the 2023 Electric Report. The tool uses AURORA output to measure select Customer Benefit Indicators (CBIs). CBIs are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group and stakeholders. These CBIs represent some of the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

Levelized Resource Costs: This workbook contains the calculations for the levelized costs of new resources in the 2023 Electric Report. The information from the raw data is processed in the resource-specific tabs. We then add processed data to the charts and data summaries.

Stochastic Modeling Results: This workbook contains the tables, charts, and data from the AURORA stochastic modeling process used in the 2023 Electric Report. The portfolios PSE examined in the stochastic modeling process are the Reference and Preferred portfolios.

➔ See Chapter Eight: Electric Analysis for a full description of the stochastic portfolio analysis and Appendix H: Electric Analysis and Portfolio Model for more information on levelized costs of resources.

3.2. PLEXOS

The PLEXOS output files contain the PLEXOS output data that PSE is able to share publicly. Table I.7 provides the file names of these datasets.

Table I.7: PLEXOS Output Files

File Names	Description
App_I_Output_Flex Benefits and Violations	Contains the calculation of the generic resource flexibility benefits and violations using output data from the PLEXOS Flexibility Analysis model.

Flexibility Benefits and Violation: This workbook contains the calculations for the resource flexibility benefits and violations. The difference in costs between the test cases and the base case provides the flexibility benefit of the test case resource.

➔ See Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model for the full flexibility analysis methodology and results.

ECONOMIC, HEALTH AND ENVIRONMENTAL BENEFITS ASSESSMENT OF CURRENT CONDITIONS

APPENDIX J

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction 1

1.1. Purpose of the Assessment 2

2. Named Communities 2

2.1. Vulnerable Populations 3

2.2. Highly Impacted Communities 5

3. Customer Benefit Indicators 8

1. Introduction

The Clean Energy Transformation Act (CETA) requires utility resource plans to ensure all customers benefit from the transition to clean energy. To achieve this goal, we conduct an economic, health, and environmental benefits assessment (assessment) every two years with each Integrated Resource Plan (IRP) and Electric Progress Report. This assessment identifies and quantifies the existing conditions for all customers and identifies disparate impacts to communities within and around PSE's service territory related to resource planning. The assessment subsequently informs development and updates to the utility's Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan (CEIP).

This assessment addresses the following areas, as defined in WAC 480-100-620 (9):[1]

- Energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities
- Energy security risk
- Long-term and short-term public health and environmental benefits, costs, and risks

We created two primary sections in the assessment to evaluate the equitable distribution of burdens and benefits.

- The first section, Named Communities, discusses how we characterize Vulnerable Populations (VPs) and Highly Impacted Communities (HIC), collectively referred to as Named Communities in the 2023 Electric Report, and the methodology we used to identify communities with higher concentrations of vulnerability factors and environmental burdens in PSE's service area.
- The second section, Customer Benefit Indicators, describes the data we use to measure current disparities in Named Communities. Customer Benefit Indicators (CBIs) are quantitative or qualitative attributes of resources or related distribution investments associated with customer benefits described in RCW 19.405.040 (8).[2] Customer Benefit Indicators will help us ensure an equitable transition to clean energy. This section describes how CBIs have evolved since the 2021 Integrated Resource Plan. (2021 IRP). We will present updates to our CBI metrics in the upcoming CEIP Biennial Update scheduled for release in the fourth quarter of 2023.

This assessment is rooted in the 2021 IRP and provides an update to that analysis. The 2021 IRP was our first attempt to identify Named Communities within PSE's service area and measure disparities in these communities. Since publishing the 2021 IRP, our methods have evolved significantly. The drivers of this evolution are twofold:

- Washington Department of Health (DOH) completed a Cumulative Impact Analysis.[3] This report designated communities highly impacted by climate change and fossil fuel pollution across Washington State.

1 WAC 480-100-620 (9)
2 RCW 19.405.040 (8)
3 Clean Energy Transformation Act – Cumulative Impact Analysis | Washington State Department of Health

- We completed our first CEIP in 2021 with guidance from a new Equity Advisory Group (EAG) and other public participation processes. The 2021 CEIP established CBIs and metrics for measuring these CBIs, and identified metrics to designate vulnerable populations in PSE's service area.

This assessment continues to build on the work completed in the 2021 CEIP to identify and measure equity for more equitable outcomes.

1.1. Purpose of the Assessment

Resource planning is a generalized and forward-looking planning process. This process forecasts new electric resource additions we will need to meet customer demand in the next twenty or more years. This 2023 Electric Progress Report (2023 Electric Report), a two-year update to the 2021 IRP, considers equity from two specific angles. First, we build a resource plan to enable more equitable customer outcomes. Second, we assess our progress toward achieving an equitable clean energy transition to learn where we currently stand. These two angles provide the context for designing specific programs and actions, which we will identify in subsequent CEIP processes.

To evaluate the relative potential for equitable energy outcomes in each electric portfolio for the report, we developed the portfolio benefit analysis tool, described in Chapter Three: Resource Plan and Chapter Eight: Electric Analysis. This tool uses forward-looking metrics to predict which generating resources we need to enable more equitable customer energy outcomes.

This economic, health and environmental benefits assessment requires backward-looking, observational metrics. These data measure our progress toward achieving an equitable clean energy transition. In contrast to the predictive nature of electric resource planning, the metrics we used in this assessment are observed characteristics of our utility, such as counts of customers with installed distributed generation. These data include specific implementation details such as location and form factor.

2. Named Communities

The Clean Energy Transformation Act requires utility resource plans to ensure all customers benefit from the transition to clean energy. The act identifies explicitly vulnerable populations and highly impacted communities as groups that should benefit from the equitable distribution of energy and non-energy benefits and the reduction of burdens. Throughout the 2021 CEIP and 2023 Electric Report development processes, we worked to understand and identify customers who may belong to these named communities through customer outreach, collaboration with the EAG, and demographic analysis of our service territory.

Named communities include vulnerable populations and highly impacted communities, each with a specific definition derived from the CETA statute and subsequent rulemaking:

- Highly Impacted Communities are communities designated by the Department of Health based on the cumulative impact analysis required by RCW 19.405.140[4] or a community located in census tracts that are fully or partially on Indian country, as defined in 18 U.S.C. Sec. 1151.
- Vulnerable Populations is a term defined by CETA as communities that experience a disproportionate cumulative risk from environmental burdens due to adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, linguistic isolation, and sensitivity factors, such as low birth weight and higher rates of hospitalization.

This section discusses how we characterize named communities for the electric progress report.

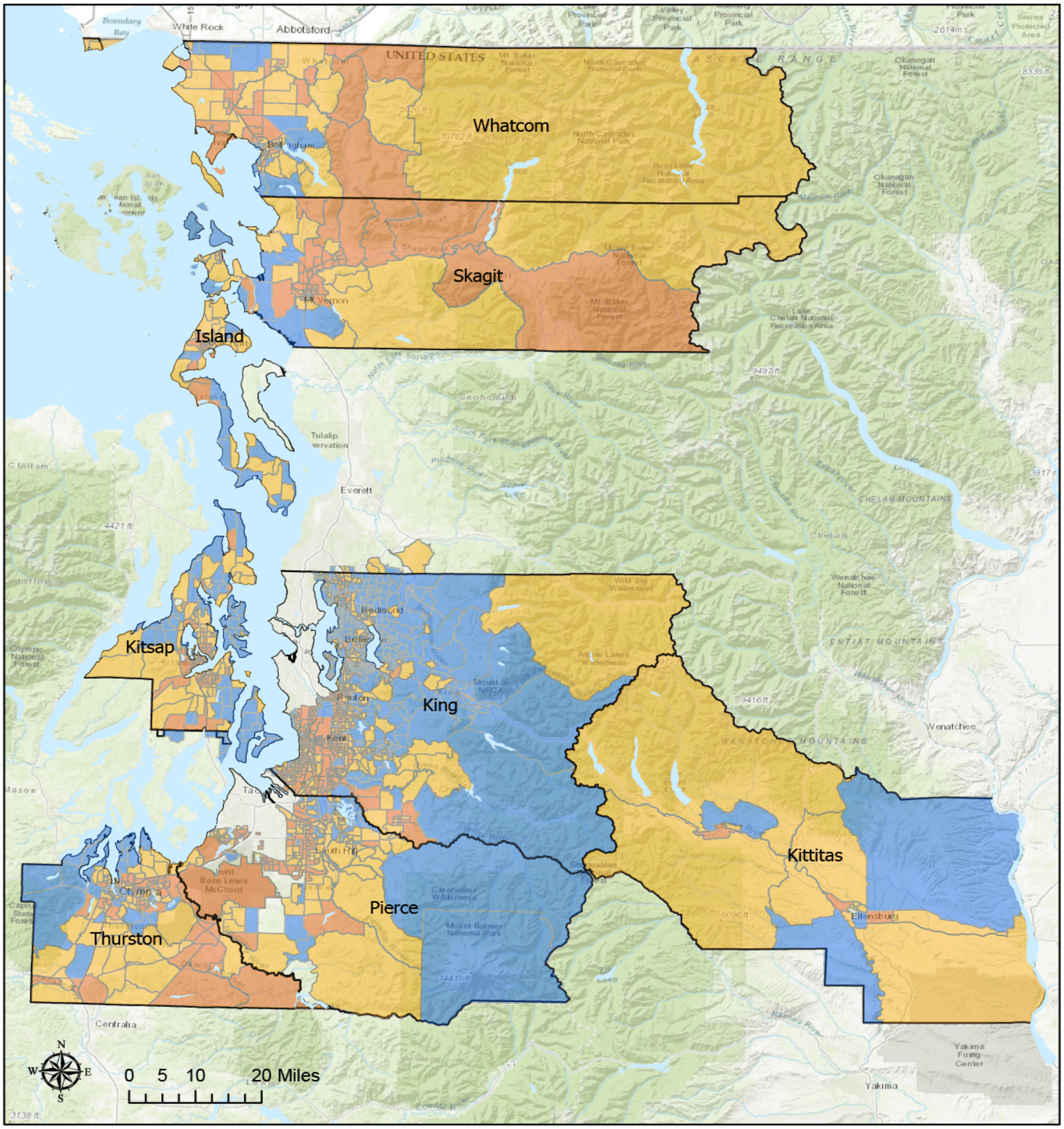
2.1. Vulnerable Populations

The CETA statute and rulemaking provide some guidance on characterizing vulnerable populations, stating that vulnerable populations experience disproportionate cumulative risk from environmental burdens due to socioeconomic and sensitivity factors. However, identifying and classifying the socioeconomic and sensitivity factors was left to the utilities' discretion. We worked with our EAG to identify attributes that may result in increased vulnerability, then aggregated the impacts of these attributes to characterize PSE's service area into three levels of vulnerability. For a complete description of the attributes and methods used to characterize vulnerable populations, please refer to Chapter Three[5] of the 2021 CEIP.

Figure J.1 is a map of vulnerable populations by census block group within PSE's electric service area created as part of the 2021 CEIP. The map illuminates the areas where customers in PSE's service area have high, medium, and low levels of vulnerability. This geographic representation indicates where we should focus outreach or program implementation efforts.

[4] RCW 19.405.140
[5] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

Figure J.1: Vulnerable Populations by Census Block Groups within PSE Electric Service Area



= Census Block groups with High level VPs

= Census Block groups with Medium level VPs

= Census Block groups with Low Level VPs

2.2. Highly Impacted Communities

Highly impacted communities are defined by the Washington Department of Health Cumulative Impact Analysis and identified as census tracts with an overall score on the Environmental Health Disparities Map[6] of nine or ten or any census tract with tribal lands.[7] The cumulative impact analysis identified 164 census tracts in our service area as highly impacted communities, of which 72 are on tribal lands, about 44 percent.

The Department of Health periodically releases a new Cumulative Impact Analysis as the Environmental Health Disparities Map is updated or new information becomes available. The highly impacted communities identified in this report are consistent with those characterized as part of the 2021 CEIP in Chapter Three[8]. We used a cumulative impact analysis from March 2021 in the 2021 CEIP. The Department of Health updated the cumulative impact analysis with the most recent results available from August 2022. We reviewed the most recent cumulative impact analysis results and observed 159 census tracts characterized as highly impacted communities, five fewer than March 2021 analysis. We maintained the highly impacted community results of the March 2021 cumulative impact analysis to preserve consistency between the 2021 CEIP and this report. We plan to explore updating our characterization of named communities as we continue to learn and evolve our methods to measure and implement equitable outcomes.

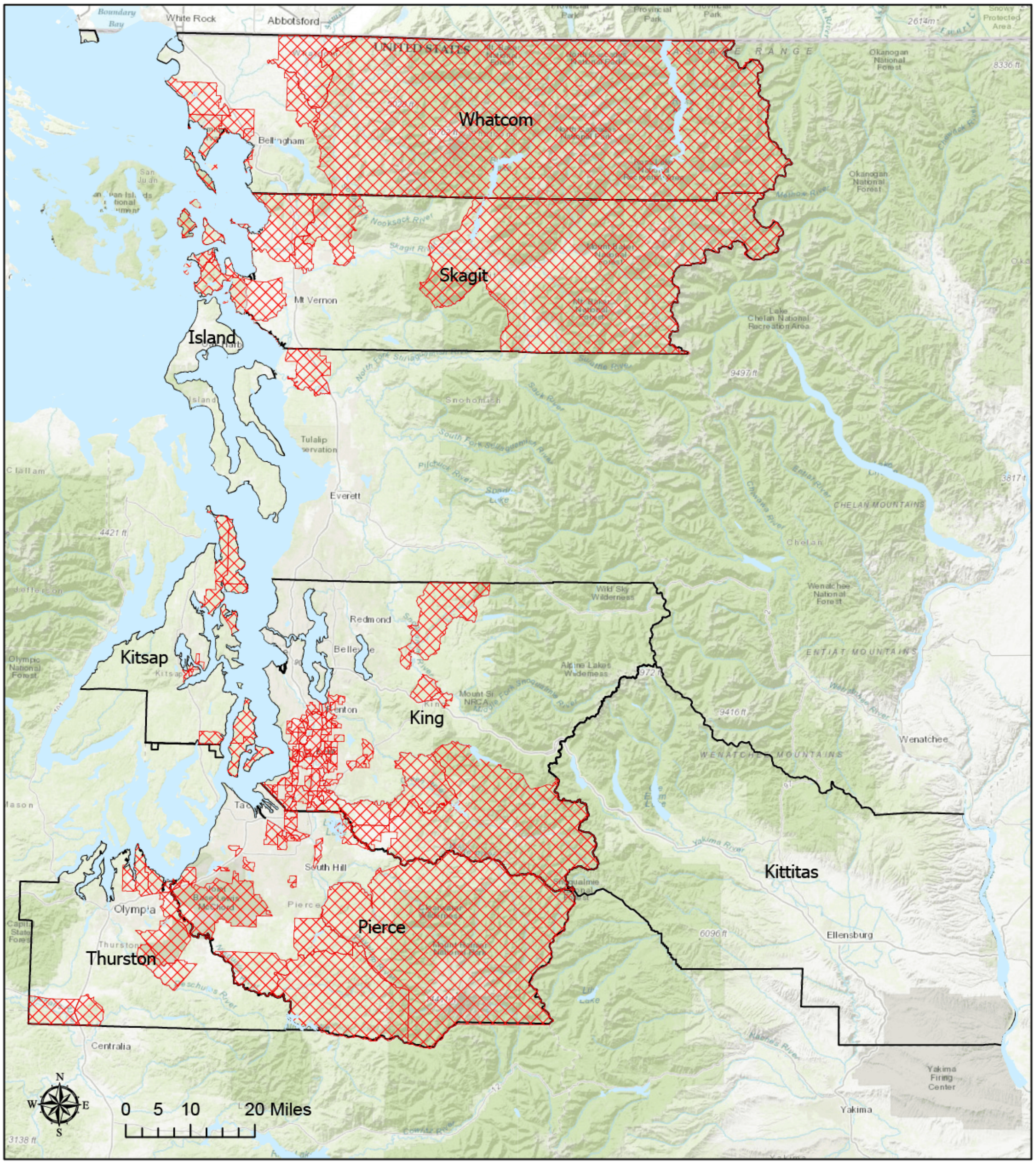
Figure J.2 presents the census tracts across PSE's service area characterized as highly impacted communities. Highly impacted communities and vulnerable populations encompass various factors to define a specific community. Some PSE customers may overlap categories and fall into either or both groups. Figure J.3 shows the overlap between highly impacted communities and the vulnerable populations within PSE's service areas. Table J.1 shows the approximate number of PSE customers who fall within each group described in this section and is consistent with data published as part of the 2021 CEIP.

[6] Information by Location | Washington Tracking Network (WTN)

[7] Clean Energy Transformation Act – Cumulative Impact Analysis | Washington State Department of Health

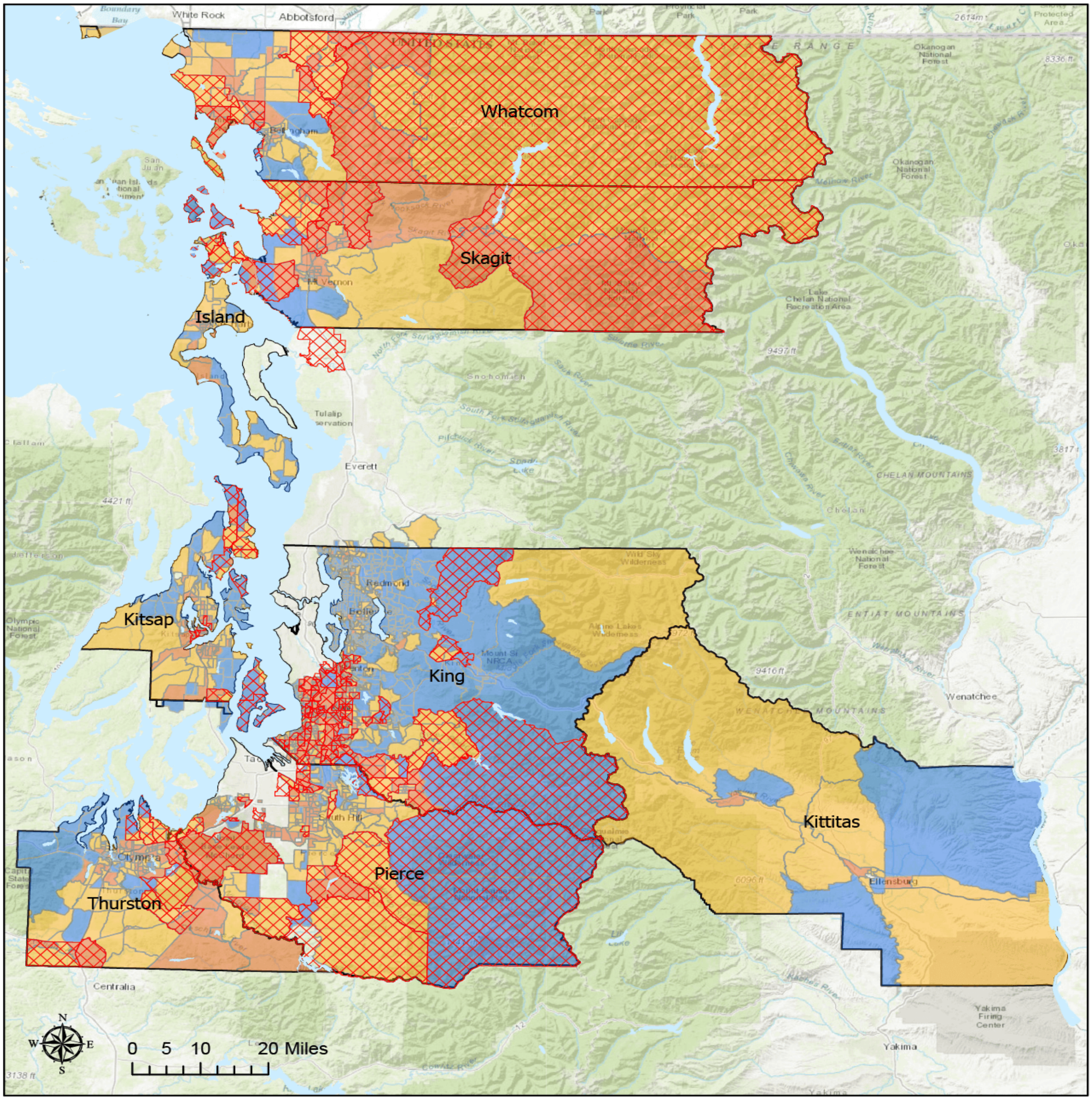
[8] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

Figure J.2: Highly Impacted Communities Census Tracts in PSE Electric Service Area



= HIC Census Tract

Figure J.3: Combined Vulnerable Populations and Highly Impacted Communities in PSE Electric Service Area



= HIC Census Tract

= Census Block groups with High level VPs

= Census Block groups with Medium level VPs

= Census Block groups with Low Level VPs

Table J.1: Number and Percentage of PSE Customers in Highly Impacted Communities and Vulnerable Populations

Customer count (PSE's electric customers)	Customers in highly impacted communities	Customers in vulnerable populations Low	Customers in vulnerable populations in Medium	Customers in vulnerable populations High
1,147,383	310,991 (27%)	333,869 (29%)	387,228 (34%)	426,286 (37%)

3. Customer Benefit Indicators

In this assessment, we measure disparities in our existing programs and resources using CBIs. We used specific metrics for each CBI to track and measure the impact of programs on the progress toward ensuring all customers benefit due to the clean energy transformation.

In the 2021 IRP[9], we presented a selection of metrics for this assessment which were our estimates of the characteristics we thought contributed to the equitable distribution of burdens and benefits. Since then, we established the EAG, published the 2021 CEIP, and engaged interested parties about incorporating and measuring equity across PSE's business. In this assessment, we present the CBIs, and accompanying metrics, developed in the 2021 CEIP[10] as a replacement for the metrics initially published in the 2021 IRP. Table J.2 defines these metrics.

Table J.2: Customer Benefit Indicators and Metrics

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
Energy Benefits Non-energy Benefits Burden Reduction	Improved participation in clean energy programs from highly impacted communities and vulnerable populations	Increase the number and percentage of participation in energy efficiency, demand response, and distributed resource programs or services by PSE customers within highly impacted communities and vulnerable populations. Increase the percentage of electricity generated by distributed renewable energy projects	Internal PSE data in which PSE measures the number of programs related to all customers and PSE customers within named communities.	Lack of awareness and education Cost of participation and economic barriers Costs and potential bill increases
Non-energy Benefits	Increase in quality and quantity of clean energy jobs	Increase quantity of jobs based on: • Number of jobs created by PSE programs for residents of highly	Unavailable currently. This information will be available in the future as PSE contracts with vendors and collects this information.	Access to high-quality jobs in clean energy

[9] Appendix K: Economic, Health and Environmental Assessment of Current Conditions; 2021 Integrated Resource Plan
[10] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
		impacted and vulnerable populations • Number of local workers in jobs for programs • Number of part-time and full-time jobs by project Increase the quality of jobs based on: • Range of wages • Additional benefits • Demographics of workers		
Non-energy Benefits	Improved home comfort	Increased non-energy benefits in Energy Efficiency Programs, measured in net present value (NPV) dollars.	Internal PSE data calculated as non-energy impacts within the BCP process.	Lack of awareness and education Cost of participation and economic barriers
Burden reduction	Increase in culturally- and linguistically-accessible program communications for named communities	Increase outreach material available in non-English languages	Internal PSE data that quantifies the number of non-English language materials used by PSE.	Lack of awareness and education
Cost Reduction Burden Reduction	Improved affordability of clean energy	Reduce median electric bill as a percentage of income for residential customers Reduce median electric bill as a percentage of income for residential customers who are also energy-burdened	Internal PSE data in which PSE measures the affordability of clean energy related to all customers and PSE customers within named communities. We may also use the Department of Energy's Lead tool.[11]	Cost of participation and economic barriers
Environment	Reduced greenhouse gas emissions	Reduce PSE-owned electric operations metric tons of annual CO_{2e} emissions. Reduce PSE contracted electric supply metric tons of annual CO_{2e} emissions.	Publicly available data on PSE CO_{2e} emissions.[12]	Adverse climate impacts of CO_{2e} emissions
Environment Risk Reduction	Reduction of climate change impacts	Increase in avoided emissions times the social cost of carbon	Public data on the social cost of carbon as defined by the WUTC[13] and data on PSE's	Adverse climate impacts of CO_{2e} emissions

[11] Low-income Energy Affordability Data (LEAD) Tool
[12] PSE Greenhouse Gas Policy Statement
[13] Washington Utilities and Transportation Commission | Social Cost of Carbon

CETA Category	Indicator	Metric	Data Source	Expected Burdens Reduced
			emissions are available on the PSE website.[14]	
Public Health	Improved outdoor air quality	Reduce regulated pollutant emissions (SO_2, NO_x, PM2.5)	Internal PSE data on emissions.	Adverse health impacts from air pollution
Public Health	Improved community health	Reduce the occurrence of health factors like hospital admittance, and work loss days	Washington Department of Health hospital discharge rates.[15]	Adverse health impacts from air pollution
Resilience	Decrease frequency and duration of outages	Decrease the number of outages, total hours of outages, and total backup load served during outages using System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) Reduction in peak demand through demand response programs	Internal PSE data on named communities and publicly available data regarding PSE's current SAIDI and SAIFI metrics are available on the UTC website.[16] Internal PSE data provided the analysis of named communities.	Dependability of variable clean electricity sources like wind and solar
Risk Reduction Energy Security	Improved access to reliable, clean energy	Increase the number of customers who have access to emergency power	Internal PSE data in which PSE measures the number of customers with storage related to all customers and PSE customers within named communities.	Lack of awareness and education Cost of participation and economic barriers Dependability of variable clean electricity sources like wind and solar

Note: Additional information on metrics used for disparity data is available in Appendix H: Customer Benefit Indicator Metrics[17] of the 2021 CEIP.

We showed data for many of these metrics in Chapter Three of the 2021 CEIP[18] and established a baseline measurement for 2020. We are working to collect and process data to extend this baseline data through recent years to track and measure CBIs across time. We plan to present updated data as part of the upcoming Clean Energy Implementation Plan Biennial Update scheduled for release in the fourth quarter of 2023.

[14] PSE Greenhouse Gas Policy Statement
[15] Hospital Discharge Data (CHARS): Washington State Department of Health
[16] Washington Utilities and Transportation Commission | Annual Reliability Reports of Electric Companies
[17] 2021 CEIP Appendix H: Customer Benefit Indicator Metrics
[18] 2021 CEIP Chapter Three: Highly Impacted Communities and Vulnerable Populations, and Customer Benefit Indicators

DELIVERY SYSTEM PLANNING

APPENDIX K

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction 1

2. Electric Projects in Implementation Phase 1

3. Electric Projects in Initiation Phase 2

3.1. West Kitsap Transmission 2

3.2. Redmond Area Distribution Capacity 3

3.3. Covington Area Distribution Capacity 3

3.4. Sumner Area Distribution Capacity 3

3.5. Yelm Area Transmission 4

1. Introduction

This appendix summarizes Puget Sound Energy's (PSE's) update to our electric delivery system 10-year plan. For a detailed description of the planning process and the status of each project, refer to the 2021 Integrated Resource Plan (IRP), Appendix M, and the PSE plan[1]. We included significant changes to project statuses from the 2021 IRP.

2. Electric Projects in Implementation Phase

Figure K.1 summarizes PSE projects in the project implementation phase, which includes design, permitting, construction, and close-out. Estimated in-service years reflect the current project status.

Figure K.1: Summary of PSE Electric Projects in Implementation

Summary of PSE Electric Projects in Implementation	Estimated In-service Year
1. Sammamish — Juanita New 115 kilovolt (kV) Line	2023
2. Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115 kV Rebuilds (Energize Eastside)	2024
3. Electron Heights — Enumclaw 55-115 kV Conversion	2025
4. Sedro Woolley — Bellingham #4 115 kV Rebuild and Reconductor	2025
5. Bainbridge Island (NWA Analysis Pilot)	2026
6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Analysis Pilot)	2024

Estimated Date of Operation: 2024

Project Need: Puget Sound Energy's 2022 needs assessment study verified a transmission capacity deficiency in the Eastside area under certain contingency conditions in the summer season. Utilizing the latest load forecast and system information, we determined this need requires Corrective Action Plans (CAPs) to manage overloads. Our 2022 needs assessment also identified a winter transmission capacity deficiency in the Eastside area for the base and sensitivity cases in the ten-year planning horizon. These deficiencies will impact reliable power delivery to PSE customers and communities in and around Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, Renton, and the towns of Yarrow Point, Hunts Point, Beaux Arts, and others.

Solution Implemented: Install a 230 kV/115 kV transformer at Richards Creek substation in the center of the Eastside load area and rebuild the 115 kV Sammamish-Lakeside-Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth.

Current Status: The south half of the project has been permitted and will be completed in 2023 when we energize the Richards Creek substation. The north half of the project (between the Sammamish substation and Richards Creek substation) is in the permitting phase; we expect it will be in service by the end of 2024. Supple chain issues, however, may delay the completion of the north half.

1 http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSE_Plan_2022_FINAL.pdf

3. Electric Projects in Initiation Phase

Figure K.2 summarizes PSE electric projects in the initiation phase, which includes determining need, identifying alternatives, and proposing and selecting solutions. The table also includes projects that have entered the initiation phase since we completed the 2021 IRP. For a detailed description of the initiation phase and the status of each project, refer to the 2021 Integrated Resource Plan: Appendix M and the 2022 PSE Plan.[1] We included significant changes to the status of projects from the 2021 IRP and details for new projects that have entered the initiation phase in this report.

Figure K.2: Summary of 10-year PSE Electric Initiation Projects

Summary of PSE Electric Projects in Initiation	Date Needed	Need Driver
7. Seabeck (Non-wires Analysis (NWA) Pilot)	Existing	Capacity, Reliability
8. West Kitsap Transmission Project (NWA Pilot)	Existing	Capacity, Operational Flexibility, Aging Infrastructure
9. Whidbey Island Transmission Improvements	Existing	Aging Infrastructure, Reliability, Operational Concerns
10. Kent / Tukwila New Substation (NWA Candidate)	Existing	Capacity, Aging Infrastructure
11. Black Diamond Area Distribution Capacity	2030	Capacity, Reliability
12. Issaquah Area Distribution Capacity (NWA Candidate)	2022	Capacity
13. Bellevue Area Distribution Capacity	2022	Capacity, Reliability
14. Juanita-Moorlands Transmission Capacity	2027	Capacity, Reliability
15. South Thurston County Transmission Improvements	2032	Capacity, Reliability
16. Electron Heights-Yelm Transmission Project	2032	Capacity, Aging Infrastructure
17. Lacey Hawks Prairie (NWA Candidate)	2024	Capacity, Reliability
18. Redmond Area Distribution Capacity	2024	Capacity
19. Covington Area Distribution Capacity	2025	Capacity
20. Sumner Area Distribution Capacity	2024	Capacity
21. Yelm Area Transmission	2032	Capacity, Reliability

3.1. West Kitsap Transmission

Estimated Date of Operation: 2028

Current Status: We identified a need to provide additional capacity in Kitsap County to serve existing customers, projected load, and improve transmission reliability for all 134,000 customers in Kitsap County and Vashon Island. We are finalizing the solutions study, which includes an analysis of non-wire alternatives and a preferred solution. The first need we addressed includes constraints on the 115 kV system serving Kitsap County under North American Electric Reliability Corporation (NERC) credible contingencies. We identified an additional need related to bulk capacity serving Kitsap County, which could lead to voltage collapse (i.e., low or rapidly falling voltage resulting in loss of service) under certain conditions. Lastly, we identified an aging infrastructure need on the submarine cables that tie

Kitsap County to King County via Vashon Island. These cables were originally installed in the 1960s and are approaching the end of their projected useful life.

We developed a solution to address these needs, including replacing and increasing the capacity of the submarine cables and the associated overhead ends to allow us to operate this normally open tie normally closed. This action addresses the aging infrastructure and bulk capacity needs for Vashon Island and Kitsap County. We will also build a new, 18-mile-115-kV backbone transmission line from Bonneville Power Administration's (BPA) Kitsap Substation in south Kitsap County to PSE's Foss Corner Substation in northern Kitsap County. This new line will address the 115 kV system constraints within Kitsap County. Our analysis identified BPA as an affected system for this solution, and further coordination with BPA may influence the final scope of this solution. Our interim operating plan to mitigate identified needs is to shift load to the South King County transmission system via the tie across Vashon Island or to shed load in North Kitsap County or Bainbridge Island.

3.2. Redmond Area Distribution Capacity

Estimated Need Date: 2024

The downtown Redmond and Redmond Ridge areas serve roughly 14,500 customers from four substations and one 115 kV transmission line. We expect the area to experience heavy load growth in the next 20 years.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in downtown Redmond and Redmond Ridge will require additional distribution substations and feeder capacity. Substation Group capacity will exceed the planning trigger in 2024, with feeder group capacity exceeded in 2026.

Current Status: A review of solution alternatives is underway, and we expect to select one in 2023.

3.3. Covington Area Distribution Capacity

Estimated Need Date: 2025

Puget Sound Energy has a project in the planning phase that we will develop to address distribution capacity constraints in the Covington area due to anticipated load growth.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in the area will require additional distribution substations and feeder capacity in the 10-year planning horizon.

Current Status: We will start the detailed needs assessment and project initiation to review alternatives in 2023.

3.4. Sumner Area Distribution Capacity

Estimated Need Date: 2024

Puget Sound Energy has a project in the planning phase that will address distribution capacity constraints in the Sumner area due to anticipated load growth.

Project Need: The need drivers for this area are capacity related.

Capacity: Several large developments in the area will require additional distribution substation capacity by 2024 and additional distribution feeder capacity by 2026.

Current Status: A review of the wires solution alternatives is underway. The non-wires analysis will begin in early 2023, and we will select a solution in mid- to late-2023.

3.5. Yelm Area Transmission

Estimated Need Date: 2032

The existing Blumaer-Electron Heights 115 kV line serves approximately 17,450 customers, 14,450 of which are in the Yelm area. Puget Sound Energy's project is in the planning phase that will improve the reliability of the existing system and increase capacity to support anticipated load growth in Yelm in the 10-year planning horizon.

Project Need: The need drivers for this area are reliability and capacity related.

Reliability: We serve customers in this area with a single, 42-mile-long transmission line subject to outages at a rate higher than the system average.

Capacity: Anticipated load growth in the area will require additional transmission lines to avoid overloads on the system under NERC-credible contingencies.

Current Status: We expect to begin the detailed needs assessment and project initiation to review alternatives in late 2023 or early 2024.

RESOURCE ADEQUACY
APPENDIX L

PUGET SOUND ENERGY

Contents

1. Introduction 1

2. Resource Adequacy Overview 1

   2.1. Energy Demand 1
   2.2. Operating Reserves 2
   2.3. Contingency Reserves 2
   2.4. Balancing Reserves 2
   2.5. Reliability Target 3
   2.6. Total Resource Need 3
   2.7. Planning Reserve Margin 4
   2.8. Capacity Credit of Resources 4
   2.9. ELCC Saturation Effect 5
   2.10. Loss of Load Probability Modeling 7

3. Resource Adequacy Inputs and Updates 8

   3.1. Background 8
   3.2. Overview of Updates 9
   3.3. Years Modeled 9
   3.4. Climate Change Impacts 10
   3.5. Seasonal Analysis 11
   3.6. Wholesale Purchase Curtailments 11
   3.7. Energy Storage Modeling 12
   3.8. Hydroelectric Generation Flexibility 13
   3.9. Wind and Solar Generation Profiles 13
   3.10. Balancing Reserves 13
   3.11. Reserve Sharing Program 15
   3.12. Other Updates Not Incorporated 15

4. Resource Adequacy Modeling Approach 16

   4.1. The Classic GENESYS Model 16
   4.2. The Wholesale Purchase Curtailment Model 17
   4.3. The RECAP Model 22
   4.4. Key Inputs to Capture Uncertainty 23

5. Detailed Results for Generic Resources 24

   5.1. Generic Wind and Solar Resource Groups 24
   5.2. Generic Wind and Solar ELCC Saturation Curves 25
   5.3. Generic Energy Storage ELCC Saturation Curves 30
   5.4. Generic Hybrid Resources 31

5.5. Generic Natural Gas Resources 32
6. Compared: the 2023 Electric Report and the 2021 Integrated Resource Plan 33
6.1. Planning Reserve Margin 33
6.2. Generic Wind and Solar Resources 34
6.3. Generic Wind and Solar ELCC Saturation Curves 35
6.4. Generic Storage and Demand Response Resources 36
6.5. Adjustments for Portfolio Analysis 37
6.6. Planning Reserve Margin 37
6.7. Storage ELCC Tranches 38
6.8. Demand Response Tranches Consolidation 39
6.9. Solar Tranches 40
6.10. Hybrid System ELCC Saturation 41
7. Western Resource Adequacy Program Methodology 42
7.1. Planning Reserve Margin 42
7.2. Qualifying Capacity Contributions 43
7.3. WRAP Solar ELCC Zones 43
7.4. WRAP Wind ELCC Zones 45

1. Introduction

To perform the resource adequacy analysis used in the 2023 Electric Progress Report (2023 Electric Report), Puget Sound Energy (PSE) contracted with the energy consulting firm Energy and Environmental Economics (E3). The firm used their RECAP model for this analysis. This appendix provides a resource adequacy overview, detailed inputs and updates, the modeling approach, and results.

2. Resource Adequacy Overview

Puget Sound Energy performs resource adequacy planning to ensure we can reliably meet future customers' energy demands. We do this by building generating capacity or acquiring capacity through contracts. Many factors can impact our ability to meet demand reliably, including variations in temperatures, power demand, energy demand, generation of various resources, equipment failures, transmission interruptions, and wholesale power supply curtailment. Resource adequacy planning allows us to consider these many uncertainties when planning our system.

The outputs from our resource adequacy analysis are key inputs to PSE's long-term portfolio analysis presented in this report. The resource adequacy analysis determines the total resource need from future resources to ensure our system remains reliable. The resource adequacy analysis also determines the capacity contributions of different resources so we can appropriately account for each resource's contribution to reliability. This section discusses critical concepts for the resource adequacy analysis, including factors influencing the total resource need and the resources' ability to contribute to satisfying that need.

2.1. Energy Demand

We plan our system to meet customers' future energy demands. Energy demand forms the basis for our plan because generation resources and transmission require years to develop and build, so we must forecast energy demand as part of our plans. Chapter Six: Demand Forecast discusses the load forecast for the 2023 Electric Report in more detail.

In addition to planning to meet expected energy demand, we must also plan our system to respond to variations in energy demand. Energy demand varies significantly throughout the year and between years due to temperature changes, among other factors. For example, demand for heat yields higher energy demand during the winter, and demand for cooling results in higher energy demand in the summer. Extreme temperatures can vary considerably between years. One year could have a week-long cold snap that significantly increases energy demand, and the following year could have a mild winter. We must plan our system to have enough resources to meet energy demands and maintain reliability across various conditions, including extreme events with low probability.

Climate change also impacts PSE's energy demand. Average temperatures have increased in the Pacific Northwest over the past decades, which is predicted to continue to increase in the coming decades. Higher temperatures raise energy demand in the summer. Moreover, climate change can make extreme events more likely, such as the extreme heat dome event the Northwest experienced in 2021. We must account for the effects of climate change on energy demand in our long-term plans to ensure resource adequacy.

2.2. Operating Reserves

In addition to supplying enough generation to satisfy energy demand, we must maintain minimum operating reserves to respond to contingencies and balance short-term, sub-hourly fluctuations in load and generation. Energy demand plus operating reserves determine the total resource requirement in each operating period. We must curtail load if PSE has insufficient resource capacity to meet this requirement and cannot rely on the wider regional energy system to fill the gap.

Load curtailment, also known as a loss of load event, reduces or discontinues energy consumption.

We included two operating reserve requirements: contingency reserves and balancing reserves in the resource adequacy analysis.

2.3. Contingency Reserves

The North American Electric Reliability Corporation (NERC) requires that utilities maintain reserves above end-use demand as a contingency to ensure continuous, reliable operation of the regional electric grid. On October 1, 2014, the Federal Energy Regulatory Commission (FERC) approved rule Bal-002-WECC-1, which requires PSE to carry reserve amounts equal to three percent of load plus three percent of online generating resources. The terms load and generation in the rule refer to the total net load and generation in PSE's Balancing Authority Area (BAA).

Puget Sound Energy participates in the Northwest Power Pool (NWPP) Reserve Sharing Program, which governs our requirement to maintain contingency reserves. In an event that causes PSE to have insufficient resources to satisfy power demand plus operating reserves requirements, we can call on the contingency reserves of other program members to cover the resource loss during the 60 minutes following the event. After the first 60 minutes, we must return to load-resource balance by re-dispatching other generating units, purchasing power, or curtailing load.

2.4. Balancing Reserves

Although we perform resource adequacy analysis hourly, utilities must also have sufficient reserves to maintain system reliability during the operating hour. We must have adequate reserves to meet load or variable resource generation fluctuations on a minute-by-minute and second-by-second basis. The resource adequacy analysis accounts for these sub-hourly fluctuations by requiring balancing reserves be held in addition to serving load and holding contingency reserves. Unlike contingency reserves, which we only utilize when the system meets specific criteria and on a short-term basis, balancing reserves are called upon regularly within an operating hour to balance the system as loads and resources fluctuate.

The consulting firm E3 calculated balancing reserve requirements on behalf of PSE. They estimated the balancing reserves by measuring the amount of intra-hour variability PSE could experience based on anticipated future resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations.

Including balancing reserves in the overall operating reserves requirements ensures that the resource adequacy analysis accounts for the sub-hourly variability we manage and meet hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's system's five-minute load, wind, and solar data. To ensure that the load, wind, and solar profiles correspond to the same underlying weather conditions and incorporate any correlations or relationships between them, E3 first obtained three years of historical weather-matched data from PSE. Then they scaled up load, wind, and solar generation to match PSE’s expected future levels. Lastly, E3 subtracted wind and solar generation from the load to obtain a net load profile for subsequent analysis. We ultimately need to manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of five-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

2.5. Reliability Target

No electricity system is perfectly reliable; there is always some chance that generator outages, transmission failures, and extreme weather conditions that impact supply and demand could lead to insufficient resources and loss of load. Therefore, we cannot plan for zero loss of load events and must set an appropriate reliability target for planning.

A reliability target sets a minimum threshold for one or more reliability metrics, ensuring the system can satisfy power and energy demand and maintain reliability across various weather and system operating conditions. There is no single reliability target in the electricity industry. System planners typically set reliability targets based on the probability of a loss of load event in a year or the frequency of loss of load events.

We plan our system to a reliability target of five percent loss of load probability (LOLP). If we maintain sufficient resources to satisfy this standard, we can expect a loss of load one year out of every twenty years. Puget Sound Energy’s five percent LOLP reliability target is consistent with the reliability target used by the Northwest Power and Conservation Council (the Council).

2.6. Total Resource Need

We conduct resource adequacy analysis based on the reliability target to determine the system’s total resource need. Total resource need is the capacity in megawatts (MW) required to satisfy the reliability target. When considering all existing and new resources, we must ensure enough capacity to meet the total resource need and the reliability target. If our existing resource portfolio falls short of the total resource need, this indicates a capacity shortfall we must meet with additional resources. The portfolio analysis modeling in the 2023 Electric Report determines what resources we should use to meet that capacity shortfall.

2.7. Planning Reserve Margin

The standard practice in the electricity industry is to express the total resource need as a planning reserve margin (PRM). The PRM is the difference between the total resource need and the utility's normal peak load, divided by the utility's normal peak load:

$$Planning\ Reserve\ Margin = \frac{(Total\ Resource\ Need - Normal\ Peak\ Load)}{Normal\ Peak\ Load}$$

The normal peak load is PSE's peak load forecast in MW. This peak load forecast is sometimes referred to as a median peak load or a one-in-two peak load because it means there is a 50 percent probability of the actual peak load being higher than this forecast and a 50 percent probability of it being lower than the forecast.

The PRM represents the resource need amount beyond the normal peak load PSE must maintain to satisfy the total resource need and, ultimately, the reliability target of five percent LOLP.

2.8. Capacity Credit of Resources

To determine whether PSE's resource portfolio satisfies the PRM, we must determine the total resource capacity that counts toward the PRM. The capacity credit of a resource is the amount the resource counts toward the PRM in MW.

The peak capacity contribution of natural gas resources is different from other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need occurs at 23 degrees Fahrenheit, we set the capacity of natural gas plants to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. However, we adjust ELCC on new generic thermal resources since the model does not account for them in the forced outages.

This adjustment includes natural gas generators and contracted power from Mid-Columbia (Mid-C) hydroelectric plants. We call out contracted power for hydroelectric plants separately from other hydroelectric generation because the contract has firm delivery, meaning the party is financially and physically obligated to deliver the agreed-upon amount of energy or capacity per the agreement. For resources whose capabilities to supply power are variable or limited — also known as dispatch-limited resources —we set the capacity credit equal to the ELCC of the resource. The dispatch-limited resources include hydroelectric, wind, solar, energy storage, contract, and demand response resources.

The ELCC is the quantity of perfect firm capacity that could be replaced or avoided by a resource while achieving our five percent LOLP. The ELCC can be expressed in MW or as a percentage of a resource's nameplate capacity. For example, a resource with an ELCC of 50 percent would mean the addition of 100 MW of the resource could displace the need for 50 MW of perfect capacity without an impact on reliability. Perfect capacity is a benchmark to quantify the contribution of dispatch-limited resources toward the PRM.

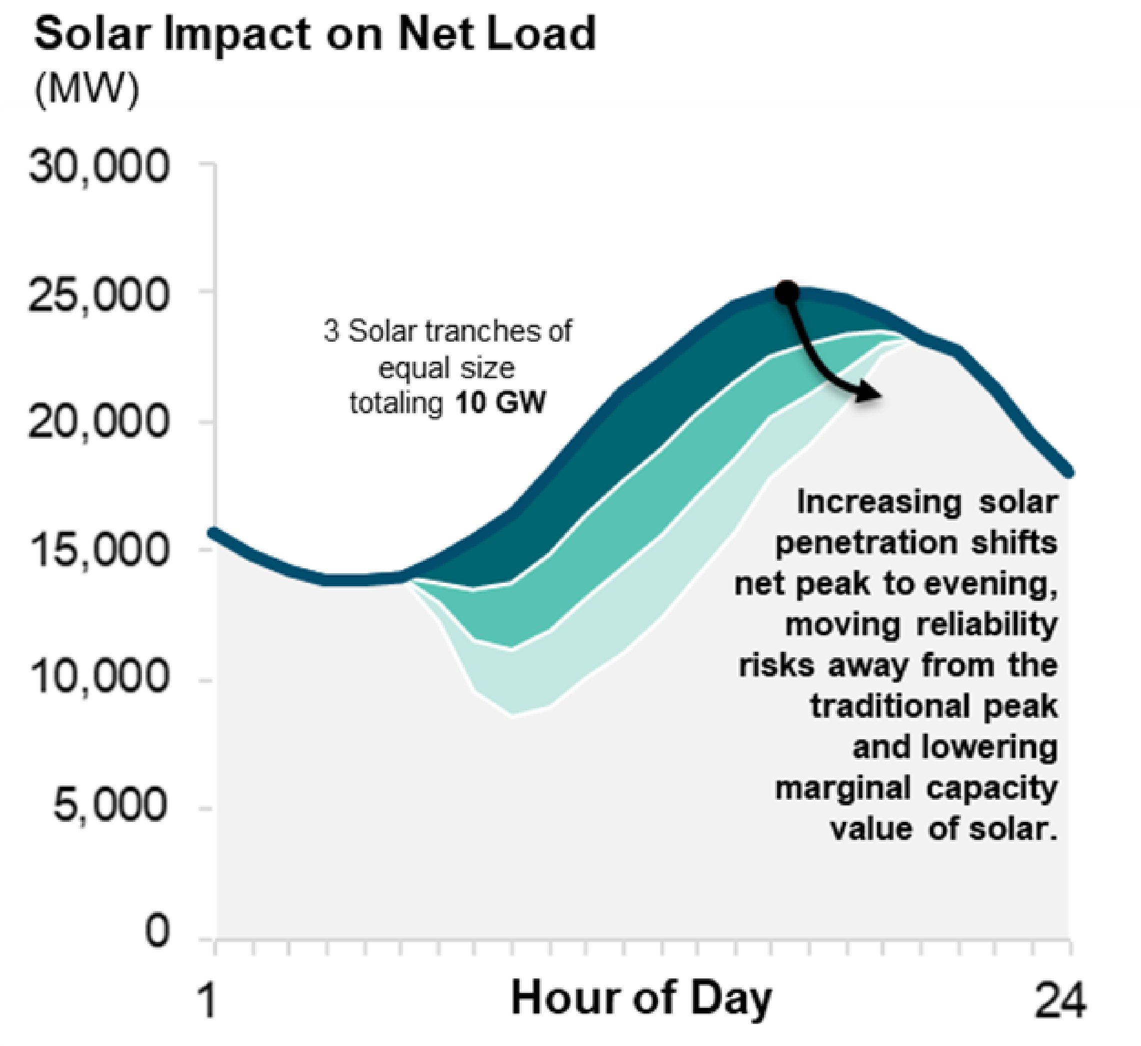
The ELCC for dispatch-limited resources is typically less than 100 percent. Wind and solar resources have an inherently variable output which may not be at maximum levels when the PSE system needs additional capacity. Energy storage resources are limited by the duration of time they can operate at full capacity. Demand response has similar limitations regarding the length and frequency of calls. The ELCC metric ensures we account for the correct contribution of each of these resources toward the PRM, which is increasingly important as we add more dispatch-limited resources to our resource portfolio.

The choice of how to assign capacity credits to resources also impacts the total resource need. Because we count natural gas and Mid-C hydroelectric resources at nameplate capacity despite their limitations — such as forced outages or limited water budget — we must ensure PSE maintains enough capacity to make up for these limitations. We calculate the total resource need to take these limitations into account.

2.9. ELCC Saturation Effect

The ELCC of a dispatch-limited resource decreases as the penetration of that resource increases, known as the ELCC saturation effect. See Figure L.1 for an example of solar dynamics on a peak summer day. Note this is an illustrative example and does not represent PSE's system. The first tranche of solar produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, adding more solar shifts the net peak demand (load minus renewable generation) into the evening when solar generation is low. As a result, the ELCC for these later tranches is lower because the solar has mitigated most reliability concerns during daytime but can't contribute to the reliability needs during nighttime hours. Wind resources experience this same saturation effect, except rather than shifting the net load from day to nighttime hours, wind resources shift the net load from when wind generation is high to when wind generation is low.

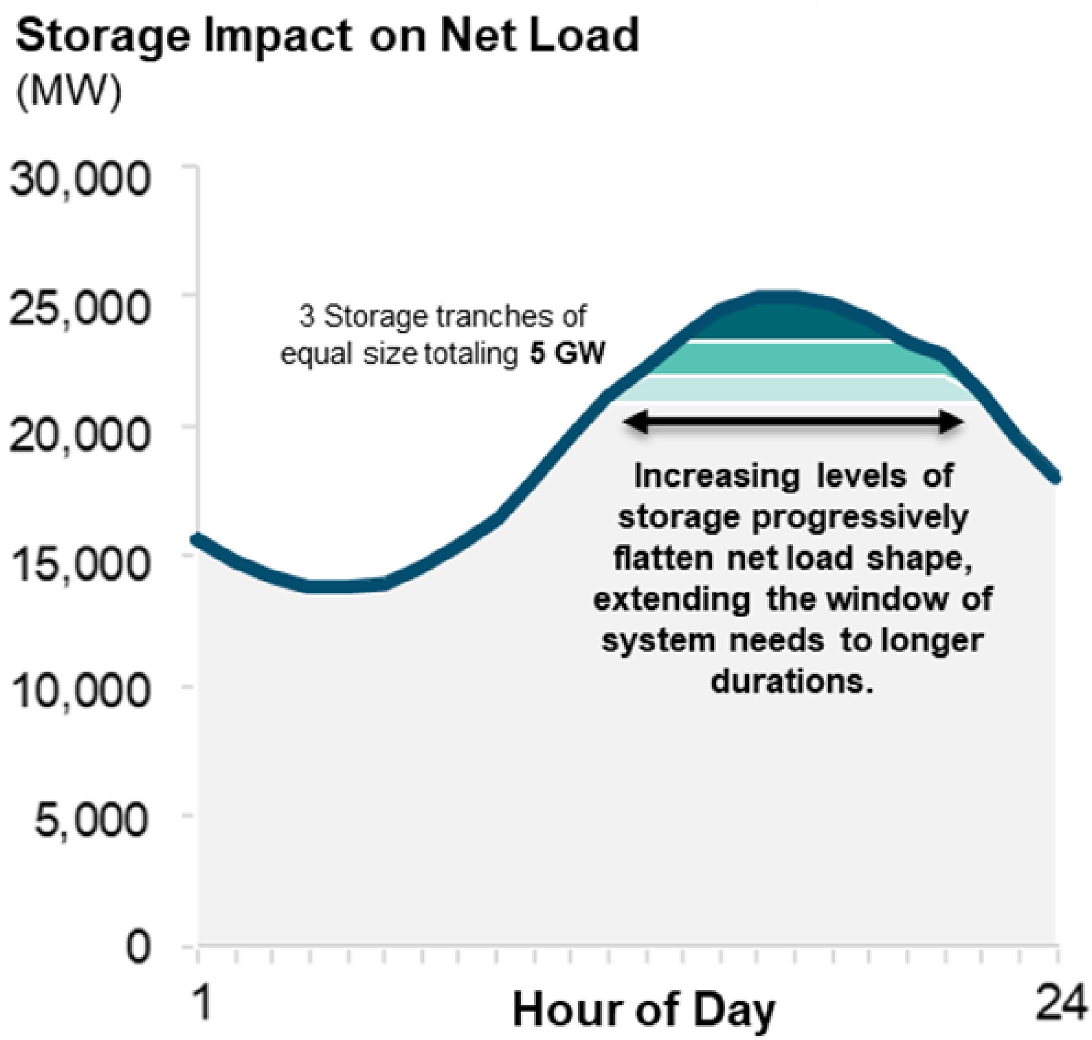
Figure L.1: Example of ELCC Saturation Effect for Solar (Does not represent PSE's system)



The ELCC saturation effect applies to other dispatch-limited resources, such as energy storage and demand response. See Figure L.2 for an example showing the dynamics for storage on the same peak day. Note that this illustrative example does not represent PSE's system.

The first tranche of energy storage produces a great deal of energy during peak demand hours, corresponding to having a relatively high ELCC. However, as we add more energy storage, the net peak demand (load minus energy storage generation) flattens and spans longer. As a result, the ELCC for these later tranches is lower because the storage is mitigated during the highest peak demand hours but can't contribute the same reliability value over longer hours due to limitations in energy available to discharge. Demand response resources experience this same saturation effect. The critical difference for demand response is that demand response resources generally have more restrictions on operations, including the number of calls and time between calls, and the length of calls but without a need of charging.

Figure L.2: Example of ELCC Saturation Effect for Energy Storage (Does not represent PSE's system)



2.10. Loss of Load Probability Modeling

To quantify the total resource need, the PRM, and the ELCC of resources, we rely on loss of load probability (LOLP) modeling. We use LOLP modeling to simulate the availability of resources to meet power demand and operating reserve requirements across a broad range of conditions. The model accounts for factors such as weather-driven load variability, forced outages of power plants, capacity derating at higher temperatures of thermal units, the natural variability of resources like wind and solar, operating constraints for hydroelectric and storage, and the availability of wholesale market purchases. To appropriately capture the risk of rare extreme events, we use LOLP modeling to simulate potential operating conditions on an annual basis hundreds of times using stochastic simulation techniques. By simulating many years, this analysis can generate the LOLP metric by comparing the number of simulations years with loss of load to the total number of simulated years, which we then compare to PSE's reliability target.

Calculating the ELCC of a resource using a LOLP model is a three-step process.

1. First, the LOLP model calibrates the system to the reliability target by adding enough perfect capacity to the existing resource portfolio, so the system exactly satisfies PSE's reliability target.

2. Then, the LOLP model adds the resource of interest to the system. Because this resource will add more resource capacity to the system, the LOLP metric will fall relative to the target: the system becomes more reliable than the reliability target.

3. Lastly, the LOLP model removes enough perfect capacity, so the system returns to PSE's reliability target. The amount of perfect capacity the model removed is the resource's ELCC in MW.

Calculating the total resource need of the system follows a different three-step process.

1. First, we estimate the ELCC of all dispatch-limited resources in the system and wholesale power purchases.

2. Next, we determine the capacity shortfall for the system: the amount of perfect capacity PSE needs in addition to the existing system to satisfy the reliability target.

3. Lastly, we sum the capacity contribution of all resources and the capacity shortfall to get the total resource need. The PRM is a simple derivation from the total resource need.

3. Resource Adequacy Inputs and Updates

We improved the inputs and methodology for the resource adequacy analysis in this report. These improvements relate to future impacts of climate change, seasonal resource needs, better representation of resource capabilities, and other factors. This section details these improvements and how they relate to assumptions in PSE's 2021 Integrated Resource Plan (IRP).

3.1. Background

Puget Sound Energy filed a draft all-source request for proposal (RFP) on April 1, 2021, to meet our capacity and clean energy resource needs established in the 2021 IRP. We received comments from interested parties and Washington Utilities and Transportation Commission (Commission) staff on that draft during a 45-day comment period. As a result of those comments, we filed revisions to the RFP in June 2021 and added a technical workshop for interested parties to discuss our ELCC methodology and assumptions.

On August 31, 2021, we held a public ELCC workshop[1] and presented the modeling approach and assumptions we used to derive the generic and resource-specific ELCC assumptions used in our planning and acquisition analyses. We gave ELCC estimates and solicited feedback from interested parties to guide and inform the 2021 all-source RFP. In response to public feedback, our Independent Evaluator, Bates White, retained consulting firm E3 to review PSE's

[1] https://www.pse.com/pages/energy-supply/acquiring-energy

methodology for calculating ELCC values. E3 issued a report[2] on October 8, 2021. Based on their review, E3 found our approach to calculating ELCCs was reasonable but recommended several areas for improvement.

On August 31, 2021, the Commission issued a public notice of opportunity to file written comments in WUTC docket UE-210220 related to PSE's ELCC estimates and use in the company's all-source request for proposals. Comments were initially due by the end of September; however, due to the timing of E3s final report, the Commission extended the comment deadline to October 22, 2021. The Commission received public comments[3] from 13 individuals and organizations regarding PSE's ELCC results and the E3 methodology and assumptions report.

➔ The full Commission docket and public comments are available on the UTC website.

In response[4] to this feedback and E3 recommendations, we made several updates to the 2023 Electric Progress Report and phase two of the 2021 RFP, described in the following sections.

Puget Sound Energy hosted a follow-up informational webinar to discuss resource adequacy on August 24, 2022. In this meeting, PSE presented the summary of E3's resource adequacy modeling results, an overview of the Western Resource Adequacy Program (WRAP), and an overview of the Northwest Regional Forecast by the Pacific Northwest Utilities Conference Committee (PNUCC).

➔ You can find all the materials from the resource adequacy webinar on the PSE website.

3.2. Overview of Updates

E3 proposed six recommendations for improvements to PSE's resource adequacy methodology. In PSE's December 2021 response comments, PSE indicated that it would attempt to incorporate these recommendations for the RFP and the 2023 Electric Report but might not be able to complete all changes due to time requirements to gather data, develop processes, update models, and benchmark results. We worked closely with E3 to implement E3's recommended updates for RFP and the 2023 Electric Report. In summary, we incorporated four of E3's six recommendations and made many other improvements to the resource adequacy analysis. Following is a description of E3's six recommendations and other changes to the analysis compared to the 2021 IRP.

3.3. Years Modeled

E3 performed a five- and 10-year resource adequacy assessment to determine the PRM. The 2023 Electric Report time horizon starts in 2024, so the five-year assessment is for October 2029–September 2030, and the 10-year

2 Review of Puget Sound Energy Effective Load Carrying Capability Methodology, https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/PSE--ELCC-StudySept-202110072021FINAL.pdf

3 https://www.utc.wa.gov/casedocket/2021/210220/docsets

4 https://apiproxy.utc.wa.gov/cases/GetDocument?docID=159&year=2021&docketNumber=210220

assessment is for October 2034–September 2035. These years are two years later than those we modeled in the 2021 IRP.

The modeled years follow the hydroelectric year (October–September) to capture the entire winter and summer seasons, consistent with the Council's GENESYS model. If we had modeled the calendar year instead, it would break up the winter season (November–March).

3.4. Climate Change Impacts

We incorporated future climate change impacts in the resource adequacy analysis for this report and relied on climate change data from the Council. Anticipated future climate change impacted four critical inputs to the resource adequacy analysis:

1. Energy demand
2. Hydroelectric generation
3. Market purchases
4. Duration and frequency of outage events

➔ For a detailed description of the load forecasts development process and inputs, see Chapter Six: Demand Forecast of the 2023 Electric Report.

These load forecasts show that PSE's system would experience much higher energy demand in summer than the load forecast we used in the 2021 IRP. Winter energy demand, however, would be at similar levels because the load data include a 30-year temperature warming trend (2020–2049), and the energy demand in summer increases meaningfully over the 30 years. However, the resource adequacy analysis applies to a single future year (2029 or 2034) and represents the amount of climate change for that year.

E3 detrended the load forecasts to correspond to a single model year (2029 or 2034) to ensure that the climate impacts for the modeled 30 years correspond to the appropriate model year while capturing the range of potential load levels for that model year. In this report, we modeled future load data that include climate change's impacts. In the 2021 IRP, we used historical load data that did not capture the future effects of climate change.

The Council also developed hydroelectric generation forecasts for each climate scenario and the two model years. The climate change forecasts influence the amount and timing of rainfall, snowmelt, and water inflows. The University of Washington Climate Impacts Group (CIG) provided water inflows for the Columbia River and coastal drainages in Washington, covering the Mid-C and Baker hydroelectric plants. The daily inflows are also for the same three climate change scenarios: A, C, and G. We then used this water inflow data to determine the total generation at each hydroelectric plant. The hydroelectric generation varies across 30 weather years, the same future weather years we used for the load forecast. In the 2021 IRP, we utilized 80 years of historical hydroelectric generation to characterize hydroelectric variability.

Lastly, we assessed the availability of market purchases from neighboring utilities and markets. Just as the climate impacts load and hydrological conditions for our system, it also impacts these conditions for the greater Pacific Northwest and the West. We used the Council's Classic GENESYS model to characterize the region's curtailments and California imports. During a Pacific Northwest-wide load-curtailment event, there is not enough physical power supply available in the area (including available imports from California) for the region's utilities to fully meet their firm loads plus operating reserve obligations.

We used the Wholesale Purchase Curtailment model (WPCM) to determine PSE's share of curtailments in the Northwest region and capture how the Pacific Northwest wholesale markets would likely operate in such a situation. To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years. This report used modeled load and hydroelectric generation data for the future to capture the impacts of climate change and performed 900 simulations. In the 2021 IRP, we used the classic GENESYS model but relied on historical load and hydroelectric generation data to perform 7,040 simulations.

These updates to our methodologies ensured we captured the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems.

3.5. Seasonal Analysis

In the 2023 Electric Report, we performed resource adequacy analysis on a seasonal rather than an annual basis. This more detailed approach allowed us to determine the resource need and assess the contribution of resources to the PRM by season. We modeled two seasons: winter, November–March, and summer, June–September.

E3's seasonal resource adequacy analysis calculated separate PRM and ELCC values for winter and summer. The seasonal PRM sets the total amount of resources needed in that season. The seasonal ELCC is a resource's contribution to the PRM by season. We calculated the PRMs for winter and summer to ensure PSE adds enough resources to satisfy them and meet our annual five percent LOLP target. We calculated the ELCCs for winter and summer, so they only consider how a resource contributes to winter and summer reliability, respectively.

3.6. Wholesale Purchase Curtailments

We updated the wholesale purchase curtailments for this report with the Classic GENESYS and WPCM. Table L.1 shows the wholesale purchase curtailment results for the 2021 IRP and the 2023 Electric Report. We based the results for the 2021 IRP on 7,040 simulations and the results for the 2023 Electric Report on 900 simulations for each climate model — 2,700 total simulations.

In winter, wholesale purchase curtailments are similar between the 2021 IRP and climate model G in the 2023 Electric Report. The average number of curtailment events, length of curtailment events, and the overall amount of curtailment are similar. However, climate models A and C in the 2023 Electric Report show less overall curtailment in winter. These two climate models exhibit more overall warming than climate model G, resulting in lower average winter temperatures and fewer wholesale purchase curtailments.

In summer, wholesale purchase curtailments significantly differ between the 2021 IRP and the 2023 Electric Report. The frequency and magnitude of curtailment events are much larger in the 2023 Electric Report. Climate model G has more curtailment events and overall curtailment than the 2021 IRP. This difference is even more pronounced for climate models A and C, which have more overall warming than climate model G.

The results in this report show wholesale purchase curtailments are less common in winter and much more common in summer. These results mean wholesale purchases will be less limited in winter and more limited in summer relative to the 2021 IRP. One caveat to this assumption is that electrification of heating demands in the future could again make winter a more constrained period for wholesale purchases. The 2023 Electric Report does not consider widespread building electrification in the future.

Table L.1: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Winter Modeling

Metric	2021 IRP[1] Winter	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.22	0.10	0.00	0.18
Average curtailment duration (hours)	37.7	8.8	2.5	28.3
Average amount of curtailment (MWh/year)	5,792	445	2	5,991

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

Table L.2: Wholesale Purchase Curtailments in the 2021 IRP and 2023 Electric Progress Report — Summer Modeling

Metric	2021 IRP[1] Summer	2023 (A)[2,3]	2023 (C)[2,3]	2023 (G)[2,3]
Average # of curtailment events per year	0.79	22.10	18.93	10.43
Average curtailment duration (hours)	9.4	10.6	9.6	10.4
Average amount of curtailment (MWh/year)	3,234	189,140	143,927	84,398

Notes:

1. The results for the 2021 IRP correspond to the model year 2027.
2. The results for the 2023 Electric Report correspond to the model year 2029.
3. A, C, and G correspond to climate models for the 2023 Electric Progress Report.

3.7. Energy Storage Modeling

We made several changes to the assumptions we used to calculate the ELCC of energy storage resources in this report:

- Storage can discharge at its rated capacity for its rated duration. A minimum state of charge does not apply to the modeled energy capacity. For example, a fully charged 100 MW four-hour lithium-ion battery resource can discharge to the grid at 100 MW for four consecutive hours.

- Storage can have forced outages. The modeled forced outage rate for lithium-ion storage is two percent, and for pumped storage is one percent.
- Storage can help meet PSE's operating reserve requirements. When providing operating reserves, storage resources are on standby and do not discharge to the grid.
- The NWPP Reserve Sharing Program can be called when an energy storage resource is added to the system.

3.8. Hydroelectric Generation Flexibility

In the 2023 Electric Report model, we allowed specific hydroelectric resources to dispatch flexibly. These resources included PSE's five contracted Mid-C hydroelectric plants, PSE's Upper Baker plant, and PSE's Lower Baker plant. PSE's Snoqualmie plant was not modeled with a climate change model and dispatch flexibility and instead had a fixed generation profile because detailed climate change data was not available from the University of Washington Climate Impacts Group for this resource. In the 2021 IRP, PSE modeled all hydroelectric resources with fixed generation profiles.

E3 modeled daily flexibility at each hydroelectric plant, meaning each can shift hydroelectric generation across hours within a single day. E3 determined the hydroelectric generation available at each plant daily based on PSE's modeling across climate models. The daily hydroelectric generation available, or daily energy budget, varies by model year (2029, 2034), climate model (A, C, G), hydroelectric plant, and day (across 30 years).

E3 also characterized the flexibility for each hydroelectric plant to shift generation within a day. E3 analyzed historical hydroelectric generation (2014 through 2021, subject to data availability) to develop relationships between the daily energy budget and the minimum and maximum hourly generation for each hydroelectric plant. E3 calculated the minimum hourly power output and maximum hourly power output for different daily energy budget ranges at each plant based on this historical data. E3 then programmed RECAP to dispatch hydroelectric plants flexibly, subject to the daily energy budget and minimum and maximum power output constraints.

3.9. Wind and Solar Generation Profiles

In the 2023 Electric Report, PSE switched to new renewable energy profiles. PSE contracted with DNV to obtain renewable profiles for each existing wind and solar resource and each candidate generic wind and solar resource. Each profile spans 250 years at an hourly resolution. These profiles capture the variability that PSE can expect from these resources on an annual, seasonal, and hourly basis. The underlying weather conditions are the same for each resource's profile, so the profiles capture correlations between resources. The 2021 IRP used profiles developed with data from the National Renewable Energy Laboratory (NREL).

3.10. Balancing Reserves

In the 2023 Electric Report, we updated the hourly balancing reserve requirements that PSE must meet. These balancing reserve requirements ensure that we have sufficient reserves to meet sub-hourly fluctuations in load or variable resource generation on a minute-by-minute basis.

E3 calculated the balancing reserve requirements on our behalf. They estimated the balancing reserves by measuring the intra-hour variability PSE could expect to experience based on expected resource buildouts. Because E3's RECAP model has hourly timesteps, it does not inherently capture sub-hourly variations. Balancing reserves as part of the overall operating reserves requirements ensures the resource adequacy analysis accounts for the sub-hourly variability, we must manage in addition to meeting hourly system needs.

E3 calculated the balancing reserve requirements by analyzing PSE's five-minute load, wind, and solar data from the three years of historical weather-matched data we provided. This ensured the load, wind, and solar profiles corresponded to the same underlying weather conditions and incorporated any correlations or relationships. E3 then scaled up load, wind generation, and solar generation to match the expected future levels on PSE's system. Lastly, E3 subtracted wind and solar generation from load to obtain a net load profile for subsequent analysis. We would manage the net load variability by dispatching other resources.

E3 compared the five-minute fluctuations in the net load to the hourly average levels for the net load to determine the magnitude of fluctuations around the hourly average net load levels. E3 then developed a 95 percent confidence interval for these fluctuations to quantify the balancing reserves for the system. The 95 percent confidence interval provides the range of 5-minute fluctuations relative to hourly net load that covers 95 percent of all observations.

Table L.3: shows the balancing reserve requirements in MW for the 2021 IRP and the 2023 Electric Report. The upward balancing reserves — reserves on standby to increase generation on demand — for the 2023 Electric Report fall within the range in the 2021 IRP.

Table L.3: Balancing Reserves Requirements (MW)

Type	2021 IRP 2025	2021 IRP 2030	2023 Electric Report 2029	2023 Electric Report 2034
Wind Capacity Balanced by PSE	875	2,375	1,215	2,915
Solar Capacity Balanced by PSE	-	1,400	-	719
Average Upward Balancing Reserves	141	492	143	210

The balancing reserves in the 2021 IRP and the 2023 Electric Report differ for two reasons:

- The PSE forecast integrated a different amount of wind and solar resources in the 2023 Electric Report.
- E3 utilized a methodology for the 2023 Electric Report that is different from the one we used in the 2021 IRP.

The 2021 IRP analysis compared the difference between the hour-ahead forecast and actual real-time values for the net load. In contrast, for the 2023 Electric Report, E3 compared the difference between the actual hourly and real-time values. E3 made this change because the balancing reserves should capture sub-hourly net load variability but should exclude any hourly forecast error that would be incorporated if using the hour-ahead forecast. Although it is important to consider hourly forecast error in the system, it does not factor into the resource adequacy analysis.

3.11. Reserve Sharing Program

We did not consistently model the NWPP Reserve Sharing Program in the ELCC of energy storage resources in the 2021 IRP. When E3 calculated this report's ELCC of energy storage resources, they maintained the same reserving sharing program assumptions across all cases.

The NWPP Reserve Sharing Program allows PSE to rely on neighboring systems to compensate for insufficient resources for the first 60 minutes following a qualifying event so we do not have to curtail load during this operating hour. E3 incorporated this assumption in their model but allowed PSE to rely on the Reserve Sharing Program only when the rest of the region has sufficient energy supplies. If PSE does not have enough resources and the wider region lacks sufficient resources, then the Reserve Sharing Program is unavailable as a last resort.

3.12. Other Updates Not Incorporated

Due to the limited time to gather data, develop processes, update models, and benchmark results, we could not incorporate two of E3's recommendations for the resource adequacy analysis. Based on the resource adequacy analysis results, E3 changed their guidance for the Classic GENESYS sensitivity and recommended not pursuing one of these recommendations. We will continue to explore the recommendation on correlations between load demand and renewable resources in future resource adequacy analyses. We described these two items in more detail in the next section.

In our December 2021 response comment filing, we said PSE would "run an additional sensitivity of a Classic GENESYS model run assuming regional capacity additions such that the region meets a 5 percent LOLP standard." We did not run this additional sensitivity. E3 initially recommended we perform this sensitivity to see if it would increase the ELCC of storage resources. However, after E3's modeling showed the ELCC of energy storage is very high (>95 percent for a four-hour lithium-ion battery), and there is sufficient energy to charge the energy storage to meet reliability needs, they recommended we not run this sensitivity as it would not add significant value considering the new results.

In our December 2021 response comment filing, we stated PSE would "follow up with E3 to explore different ways to approach correlations between wind/load and solar/load." We also indicated we might need to consider this recommendation for future IRP cycles to allow adequate time for model preparation and quality review.

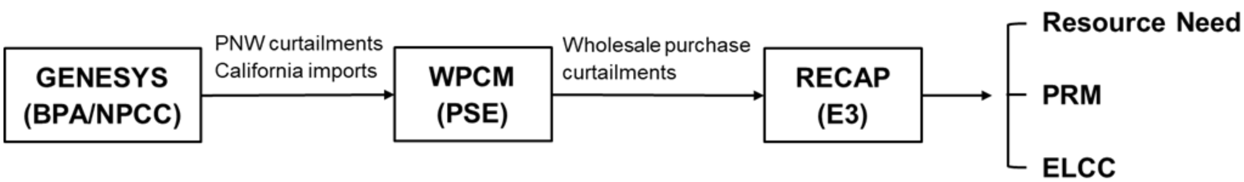
In addition to updating the load profiles based on climate change impacts, we also updated the renewable energy profiles. With changes to load profiles, renewable profiles, and many other assumptions for Phase 2 of the 2021 All-Source RFP and the 2023 Electric Report, we did not have sufficient time to incorporate load and renewable correlations in the resource adequacy analysis. These correlations warrant study for future analysis, as they could impact resource adequacy for PSE's system. For example, a cold snap in winter could result in high energy demand and low renewable output simultaneously, resulting in more extreme conditions for maintaining resource adequacy.

4. Resource Adequacy Modeling Approach

In this report, we relied on a similar set of models to those we used in the 2021 IRP. We used the Classic GENESYS model developed by the Council and Bonneville Power Administration (BPA) to analyze load and resource conditions for the Pacific Northwest region. We used PSE's wholesale purchase curtailment model (WPCM) to investigate the impacts of regional load curtailments on our system. Rather than use our resource adequacy model (RAM) to analyze load and resource conditions for PSE's system, we asked E3 to perform LOLP modeling using their proprietary RECAP model[5].

Figure L.3 shows how the three models work together. Because PSE has historically relied on significant wholesale power purchases to maintain reliability, the analysis includes an evaluation of potential curtailments to regional power supplies. The Classic GENESYS model characterizes when the region is short (i.e., insufficient resources to meet energy demand plus operating reserves). The WPCM characterizes how PSE would curtail wholesale power purchases when the region is short on energy. Lastly, RECAP simulates PSE's resource need and availability across hundreds of simulation years to determine the resource need and calculate other reliability metrics. The rest of this section describes each of the three models and the types of inputs for this analysis.

Figure L.3: Models in the Resource Adequacy Analysis



4.1. The Classic GENESYS Model

The Council and the Bonneville Power Administration (BPA) developed the Classic GENESYS model for regional-level load and resource studies. Classic GENESYS is a multi-scenario model that incorporates 30 years of hydroelectric conditions and, as of the 2023 assessment, 30 years of temperature conditions. For the 2023 Electric Report, we started with the Classic GENESYS model from the Council power supply adequacy assessment for 2023.

When the model combines thermal plant forced outages and the mean expected time to repair those units, variable wind plant generation, and available power imports from outside the region, it determines the PNW's overall hourly capacity surplus or deficit in 900 multi-scenario simulations. Since the Classic GENESYS model includes all potentially available supplies of energy and capacity an operator could use to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[6]

[5] Due to staffing constraints, PSE engaged E3 to perform this analysis.

[6] We included operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) in the Classic GENESYS model. A PNW load-curtailment event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, Classic GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydroelectric resources to the maximum extent possible within a defined set of operational constraints. Classic GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) with forward and short-term purchases.

Since we set the Classic GENESYS model for a 2023 assessment, we made some updates to capture regional load and resource changes to run the model for 2029 and 2034. The updates to the GENESYS model include the following:

- Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW)
- The Council used climate data developed by the River Management Joint Operating Committee (RMJOC) in the Classic GENESYS load model for the 2021 power plan. We used three climate change models, A, C, and G, representing CanESM, CCSM, and CNRM in the GENESYS model[7]. For details regarding the various climate change models, please refer to Chapter Six: Demand Forecast.
- Updated coal plant retirements with retirement years are in Table L.4.

Table L.4: Modeled Coal Plant Retirements

Plant	Year Retired in Model
Hardin	2018
Colstrip 1 & 2	2019
Boardman	2020
Centralia 1	2020
N Valmy 1	2021
N Valmy 2	2025
Centralia 2	2025
Jim Bridger 1	2023
Jim Bridger 2	2028
Colstrip 3 & 4	2025

We did not include any other adjustments to Classic GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from the Council already built into the model.

4.2. The Wholesale Purchase Curtailment Model

During a PNW-wide load-curtailment event, the region lacks enough physical power supply (including available imports from California) for the area's utilities to meet their firm loads plus operating reserve obligations fully. To mimic how the PNW wholesale markets would likely work in such a situation, PSE developed the wholesale purchase

7 For more details about the climate change model, refer to the NWPCC Climate Change Scenario Selection Process and the River Management Joint Operating Committee (RMJOC) report.

curtailment model (WPCM) as part of the 2015 IRP. The WPCM links regional events to their impacts on PSE's system and our ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

The amount of capacity that other load-serving entities in the region purchase in the wholesale marketplace directly impacts how much capacity PSE can purchase. Therefore, the WPCM first assembles load and resource data for the region and many utilities in the region, especially those expected to buy relatively large amounts of energy and capacity during winter peaking events.

We used the capacity data in BPA's 2018 Pacific Northwest Loads and Resources Study for this analysis. The BPA published the 2019 Pacific Northwest Loads and Resources Study[8] in October 2020. Commonly referred to as the White Book, the 2019 report presents the region's load obligations, contracts, and resources for operating years 2021 through 2030. Under critical water conditions, the BPA study forecasts unbalanced energy from a deficit of 194 MW to a surplus of 354 MW. The annual energy deficits and surplus forecasts are similar to the forecasts in the 2018 White Book. We used the same forecasts in the 2021 IRP in this report and will incorporate the updated forecasts for future IRP cycles.

4.2.1. Allocation Methodology

The WPCM then uses a multi-step approach to allocate the regional capacity deficiency among the region's utilities. We reflected these individual capacity shortages via a reduction in each utility's forecasted level of wholesale market purchases. The WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a decrease in PSE's wholesale market purchases hourly. In some cases, PSE's initial desired wholesale market purchase volume reductions could trigger a load-curtailment event in the LOLP portion of RECAP.

To assess a wide range of regional market conditions, we combined the 30 years of energy demand forecasts with each of the 30 years of hydroelectric generation forecasts to simulate the availability of market purchases across 900 simulation years.

In the study, we used the three climate change models to capture the future impacts of climate change on energy demand, hydroelectric generation, and availability of market purchases from other systems. We also updated the model's contracts, third-party generation, and loads.

It is worth noting that no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

4.2.2. Forward Market Allocations

The model assumes each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility can purchase its target capacity in these markets, reducing the remaining capacity available in the spot markets. If the wholesale market does not have enough capacity to satisfy all

8 BPA's 2019 Pacific Northwest Loads and Resources Study is at https://www.bpa.gov/-/media/Aep/power/white-book/2019-wbk-summary.pdf.

the forward purchase targets, the model reduces those purchases on a pro-rata basis based on each utility's initial target purchase amount.

Besides the market purchase, the WPCM model uses the Mid-C transmission line to transmit the PSE Mid-C project and the Wild Horse site power to PSE. The model also uses transmission capacity to get balancing and spinning reserves, which is 50 percent of the operating reserve. We use the remaining capacity for market purchases.

4.2.3. Spot Market Allocations

For spot market capacity allocation, we assumed each of the five large utility purchasers to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation is not based on a straight pro-rata allocation because, in actual operations, the largest purchaser (usually PSE) is not guaranteed automatic access to a fixed percentage of its capacity need. Instead, all the large purchasers aggressively attempt to locate and purchase scarce capacity from the same sources. Under deficit conditions, the largest purchasers tend to experience the biggest MW shortfalls between what they need and can buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs, but the larger purchasers cannot.

4.2.4. WPCM Outputs

For each simulation and hour in which the Council's Classic GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- Puget Sound Energy's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions
- Puget Sound Energy's initial wholesale market purchase amount (in MW) limited only by PSE's overall Mid-C transmission rights
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage

Figure L.4, Figure L.5, Figure L.6, Figure L.7, Figure L.8, and Figure L.9 show the results of the WPCM. The charts illustrate the PSE's average share of the regional deficiency. The results show the deficiency in each of the 900 simulations (gray lines) and the mean of the simulations (red line). The mean deficiency is close to zero, but in some simulations, the market purchases may be limited by 1000 MW (in August 2029 Model A) and 1200 MW (in August 2034 Model A). This means that of the 1,500 MW of available Mid-C transmission, we could only fill 500 MW in August 2029 Model A and 300 MW in August 2034 Modal A.

Figure L.4: Average Curtailment by Month, 2029 Model A

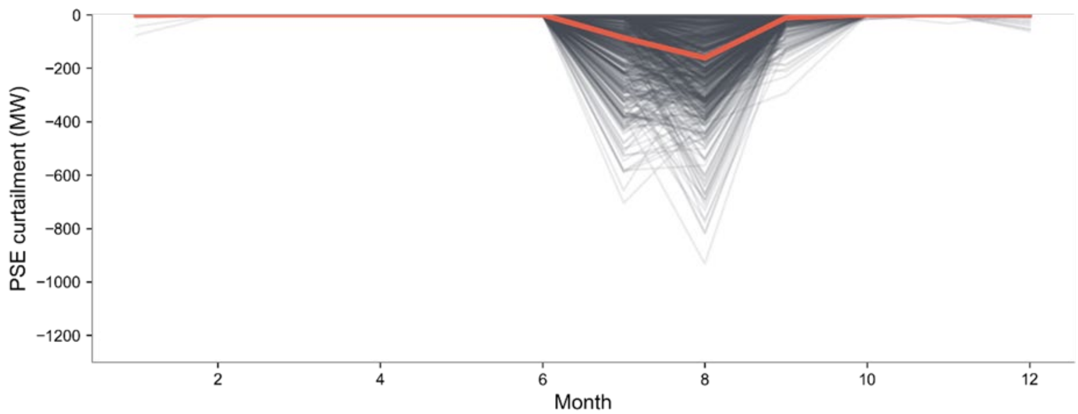


Figure L.5: Average Curtailment by Month, 2029 Model C

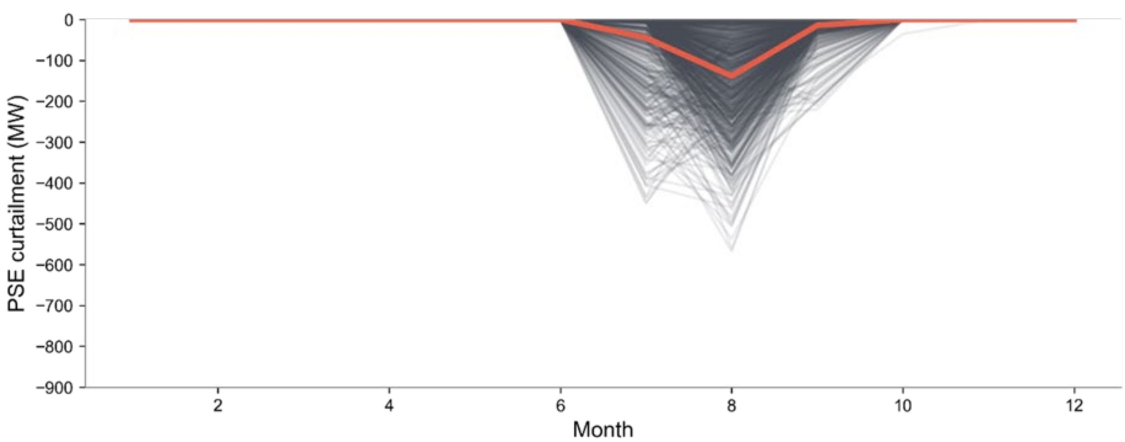


Figure L.6: Average Curtailment by Month, 2029 Model G

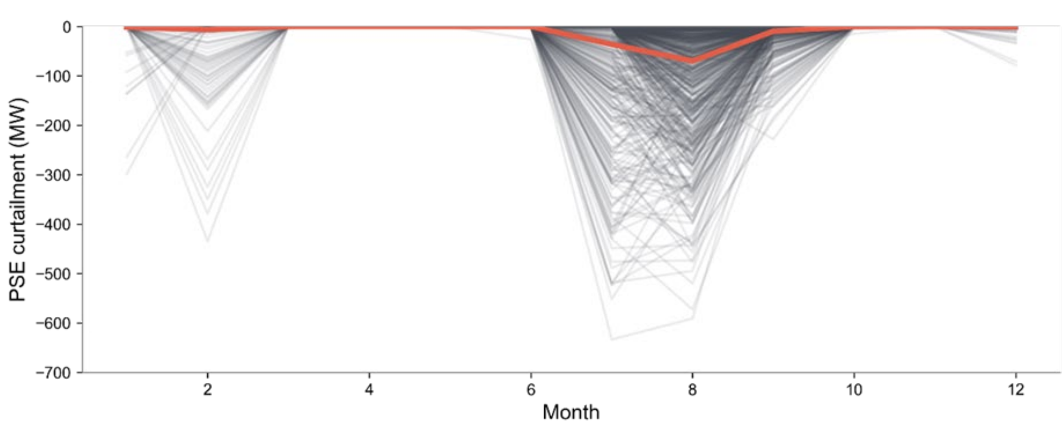


Figure L.7: Average Curtailment by Month, 2034 Model A

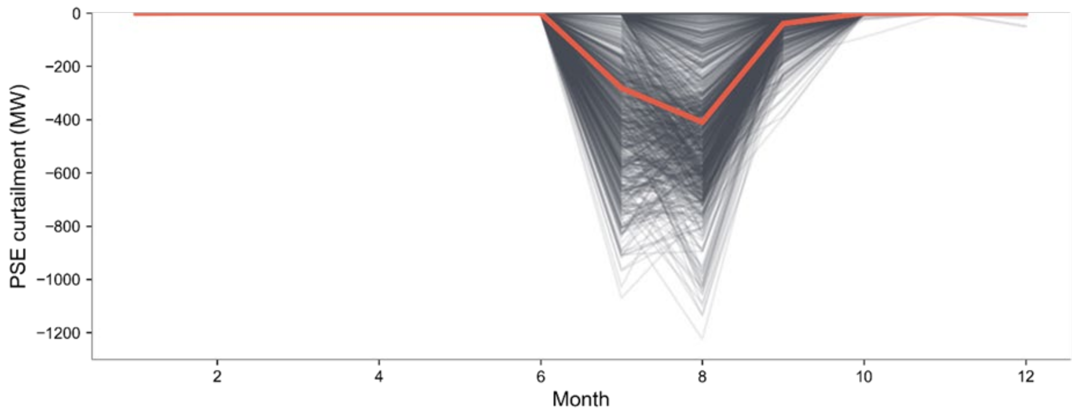


Figure L.8: Average Curtailment by Month, 2034 Model C

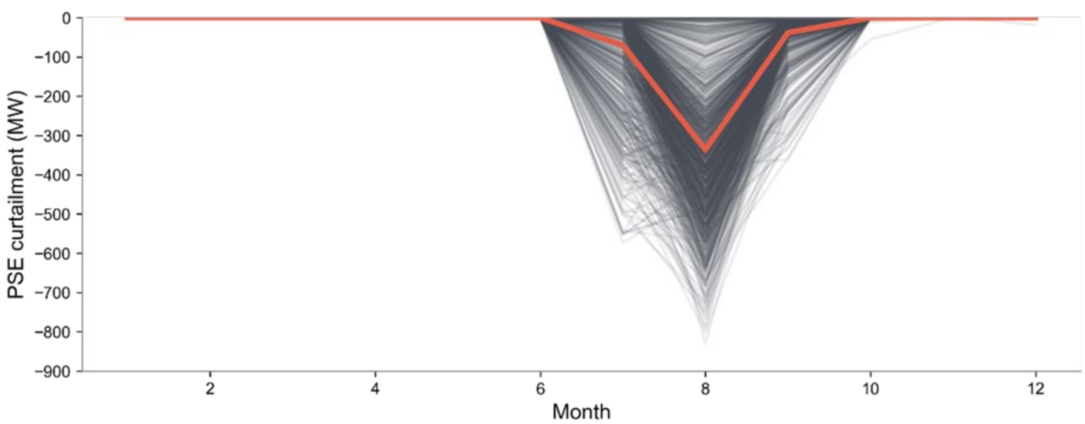
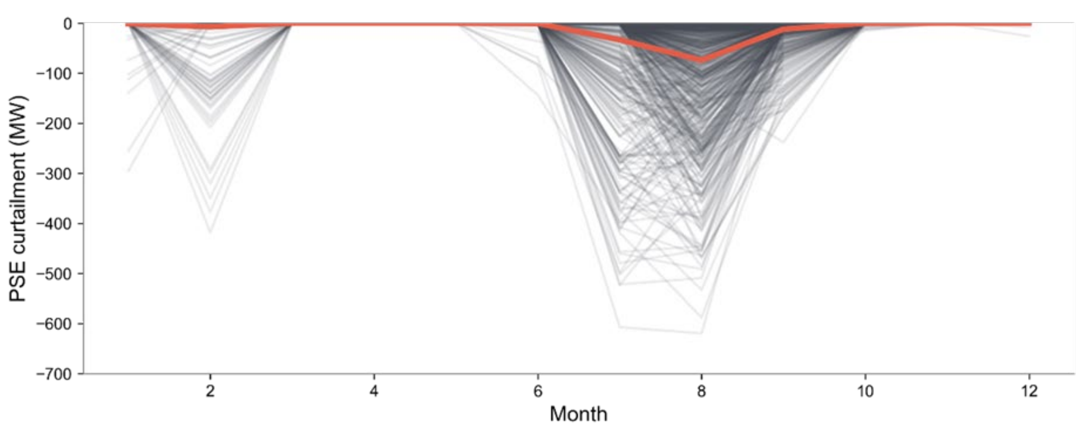


Figure L.9: Average Curtailment by Month, 2034 Model G



In addition to the WPCM results included in PSE's resource adequacy analysis, we also conducted a separate market risk assessment. That assessment is described later in this chapter.

4.3. The RECAP Model

E3 used its RECAP model to determine the PSE system's resource need, PRM, and ELCC metrics. E3 has used RECAP extensively to assess the resource adequacy of electric systems across North America. In the Western United States, E3 used RECAP in the following states: Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, and Washington.

RECAP is a LOLP model that simulates the availability of resources to meet energy demand across a broad range of conditions. RECAP accounts for factors such as weather-driven variability of electric demand, the natural variability of resources such as wind and solar, availability of wholesale purchases, forced outages of thermal power plants, and operating constraints for resources like hydroelectric, storage, and demand response. These simulations determine the likelihood and magnitude of loss of load — energy demand that PSE cannot serve — and provide the basis for assessing resource adequacy for PSE's system.

RECAP simulates system conditions over hundreds of simulation years using stochastic techniques to capture the risk of rare tail events that can significantly impact PSE's system. RECAP simulates the system each hour of a year and repeats this process hundreds of times with different system conditions, which ensures that RECAP captures a wide distribution of potential outcomes, including low-probability but high-risk tail events.

RECAP conducts a Monte-Carlo time-sequential simulation of loads, resources, and power purchases for each simulation year. RECAP first determines the load based on the simulation year and calculates the operating reserve requirements hourly. RECAP then simulates renewable generation and forced outages for thermal generators. After this, RECAP determines the number of wholesale power purchases available based on the simulation year. RECAP then dispatches hydroelectric resources that have the flexibility to shift generation throughout the day to maximize generation during the times when the PSE system has the greatest need. Lastly, RECAP dispatches storage and demand response resources.

Energy storage devices charge when sufficient capacity is available and discharge to meet energy demand not met by other resources. RECAP tracks energy storage resources' state of charge (SoC) to ensure their operations respect physical limitations. Demand response resources serve as a last resort and are constrained by limits on the number and duration of calls. If there is a period when the supply of resources is inadequate to meet the load requirement, there is a loss of load event.

RECAP determines the frequency, duration, and magnitude of the loss of load events across all simulation years. RECAP then uses these outputs to calculate PSE's system's resource need, PRM, and ELCC metrics.

Detailed documentation of E3's RECAP model is on E3's website[9].

[9] https://www.ethree.com/wp-content/uploads/2022/10/RECAP-Documentation.pdf

4.4. Key Inputs to Capture Uncertainty

To perform the resource adequacy analysis, we must appropriately characterize the range of operating conditions PSE can expect over a long time, including low-probability tail events. This analysis must capture the uncertainties in power and energy demand and resource supply that could ultimately lead to load loss. These factors include energy demand, availability of thermal generators, availability of hydroelectric, wind, and solar generation, and availability of market purchases. The resource adequacy analysis for the 2023 Electric Report captures each of these factors, described further in the following and the Resource Adequacy Inputs and Updates sections.

4.4.1. Energy Demand

We modeled hourly system loads as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 30 temperature years. These demand draws created with stochastic outputs from PSE's economic and demographic model and two consecutive historical weather years predict future weather. Each coming weather year from 2020 to 2049 is represented in the 30 weather draws. Since the resource adequacy model examines a hydroelectric year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. The model also examines adequacy in each hour of a given future year; therefore, we scaled the model inputs to hourly demand using the hourly demand model.

4.4.2. Forced Outages

A forced outage is when a generator fails unexpectedly and cannot generate at maximum output for some amount of time until repaired. We accounted for forced outages for natural gas and storage units by modeling forced outage rates (FOR) and mean time to repair (MTTR) for each resource. The method for modeling forced outage rates in the resource adequacy analysis is consistent with our frequency duration outage method in AURORA, which allows units to fail and return to service at any timestep within the simulation.

4.4.3. Hydroelectric Generation

We use the same 30 hydroelectric years, simulation for simulation, as the GENESYS model. Based on PSE's modeling of daily We hydroelectric availability for each hydroelectric year, E3 models PSE's Mid-Columbia and Baker River plants flexibly in RECAP, so each plant can shift hydroelectric generation across hours within a single day, subject to daily energy budget and power output constraints. The 900 combinations of hydroelectric and temperature simulations are consistent with the Classic GENESYS model.

4.4.4. Wind and Solar Generation

We modeled 250 unique 8,760 hourly profiles exhibiting typical wind and solar generation patterns. Since wind and solar are both intermittent resources, one of the goals in developing the generation profile for each wind and solar project considered is to ensure that we preserved this intermittency. The other goal is to ensure that we reflect correlations across wind farms and the seasonality of wind and solar generation. DNV, an energy and atmospheric science consultant, provided wind speed and solar irradiance data to PSE. Wind and solar data were selected for specific sites representing locations of generic resources and processed to give wind and solar production data. DNV utilized its stochastic engine to generate 1,000 unique 21-year production profiles for each site. From the 1,000 unique profiles, we selected 250 to use in the resource adequacy model. Statistical analysis of these 250 randomly selected profiles ensured that they represented the entire population of wind and solar profiles.

➔ Details of the profiles provided by DNV and DNV's methodology are available in Appendix C: Existing Resource Inventory and Appendix D: Generic Resource Alternatives.

4.4.5. Wholesale Market Purchases

These inputs to RECAP are determined in the WPCM, as explained. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same classic GENESYS model simulations as E3's RECAP. We computed the initial set of hourly wholesale market purchases that we import into our system using our long-term Mid-C transmission rights as the difference between PSE's maximum import rights less the amount of transmission capability required to import generation from PSE's Wild Horse wind farm and PSE's contracted shares of the Mid-C hydroelectric plants.

To reflect regional deficit conditions, we reduced this initial set of hourly wholesale market imports on the hours when we identified a PNW load-curtailment event in the WPCM. We then used the final set of hourly PSE wholesale imports from the WPCM as data input into RECAP and determined PSE's loss of load probability, expected unserved energy, and loss of load expectation. In this fashion, the LOLP, EUE, and LOLH metrics determined in RECAP incorporate PSE's wholesale market reliance risk.

5. Detailed Results for Generic Resources

The following section shows the detailed results regarding the generic resources we modeled in the 2023 Electric Progress Report.

5.1. Generic Wind and Solar Resource Groups

E3 calculated the ELCC for eight wind resources, two distributed solar resources, and five utility-scale solar resources (see the results section of Chapter Seven: Resource Adequacy). These ELCC values represent the capacity contribution for the first 100 MW of incremental capacity we added to PSE's system; the ELCC would be different if we added more than 100 MW to the system, as discussed in the next section.

As discussed in section 6.3 of this appendix, the ELCC for a dispatch-limited resource declines as its penetration increases. We modeled an ELCC saturation curve for each wind and solar resource to capture this relationship between ELCC and penetration.

E3 first categorized the generic wind and solar resources into resource groups (see Table L.5). Each resource group includes resources that have highly correlated generation profiles. When one resource in a group has a high generation, additional resources in the group likely have a high generation. Just as higher penetration of a single resource results in a lower ELCC for that resource, higher penetration of highly correlated resources also results in a lower ELCC. Highly correlated resources make similar contributions towards meeting load during critical periods, so adding one of these resources will cause the reliability value — or ELCC — of the other resources to decline or saturate.

Table L.5: Resource Groups for ELCC Saturation

Resource Group	Resources in Group
Pacific Northwest Wind	British Columbia; Washington
Rockies Wind	Wyoming East; Wyoming West; Montana Central; Montana East
Idaho Wind	Idaho Wind
Offshore Wind	Offshore Wind
Solar	Idaho Solar; Washington East; Washington West; Wyoming East; Wyoming West; Distributed Ground Mount; Distributed Rooftop

Note that there can be interactions between all resources, not just those in the same resource group. However, due to the large number of potential resource combinations, it was not feasible for E3 to model the interactive and saturation effects between all resources. Moreover, PSE's capacity expansion model cannot incorporate a multi-dimensional ELCC surface. The more straightforward resource group approach still provides a way to capture the strongest and most important interactions between highly correlated resources, as it allows us to calculate the capacity contribution of an individual resource based on the overall penetration of resources in its corresponding resource group.

5.2. Generic Wind and Solar ELCC Saturation Curves

Figure L.10 shows the winter and summer ELCC saturation curves for the Pacific Northwest wind (including the British Columbia wind and Washington wind). E3 calculated the ELCC for three tranches of Pacific Northwest wind: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. The ELCC declines with each successive tranche due to the ELCC saturation effect. For example, the first tranche of Washington wind has an ELCC of 13 percent in winter, the second has an ELCC of 11 percent, and the third has an ELCC of 6 percent.

The ELCC saturation curve determines how much a resource contributes toward the PRM. For example, assume that PSE adds 1,500 MW of Washington wind. The total capacity contribution of this incremental capacity would be 13 MW for the first tranche (100 MW x 13 percent), plus 99 MW for the second tranche (900 MW x 11 percent), and 30 MW for the third tranche (500 MW x 6 percent), for a total of 142 MW.

The total capacity additions within the resource group determine the overall penetration for all resources in the resource group. For example, assume that PSE adds 1,000 MW of Washington Wind in an earlier year and then adds 500 MW of British Columbia Wind in a later year. The ELCC for the 500 MW of British Columbia Wind would be 16 percent because the penetration for the resource group is already at 500 MW, putting the incremental British Columbia Wind in the third tranche.

Figure L.10: ELCC Saturation Curves for Pacific Northwest Wind

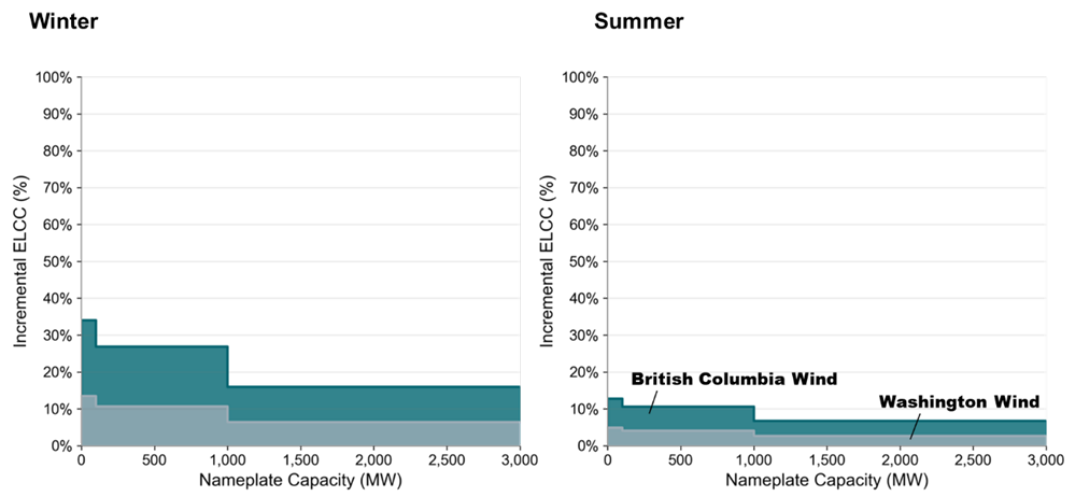


Figure L.11 shows the winter and summer ELCC saturation curves for the Rockies Wind (including Montana Central Wind, Montana East Wind, Wyoming East Wind, and Wyoming West Wind). E3 calculated the ELCC for three tranches for Pacific Rockies Wind: 0–100 MW, 100–1,000 MW, and 1,000–2,000 MW. The Montana East Wind ELCC is lower than the ELCC of the other resources because we already have 350 MW of wind in eastern Montana in its resource portfolio (Clearwater Wind). Note that the ELCC of Montana Central Wind and Wyoming West Wind are very similar in winter, so the figure does not differentiate between these resources. The ELCC of Wyoming East Wind and Wyoming West Wind are similar in summer, so the figure does not distinguish between these two resources.

Figure L.11: ELCC Saturation Curves for Rockies Wind

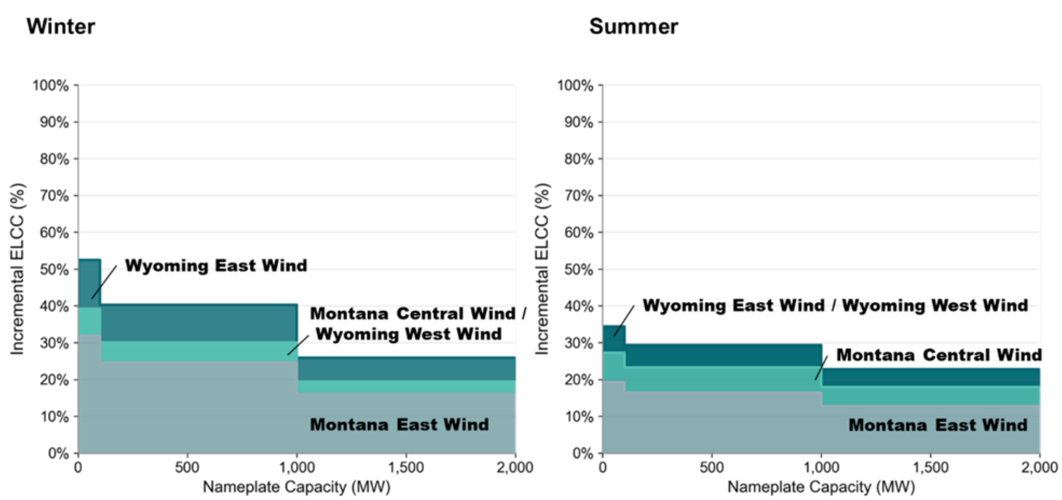


Figure L.12 shows the winter and summer ELCC saturation curves for Idaho and Offshore Wind. E3 calculated two tranches for Idaho Wind: 0–100 MW and 100–800 MW. E3 calculated the ELCC for two tranches of Offshore Wind: 0–100 MW and 100–300 MW. Note that Idaho Wind and Offshore Wind are not in the same resource grouping, so the penetration of one does not impact the penetration of the other when determining ELCC saturation.

Figure L.12: ELCC Saturation Curves for Idaho Wind and Offshore Wind

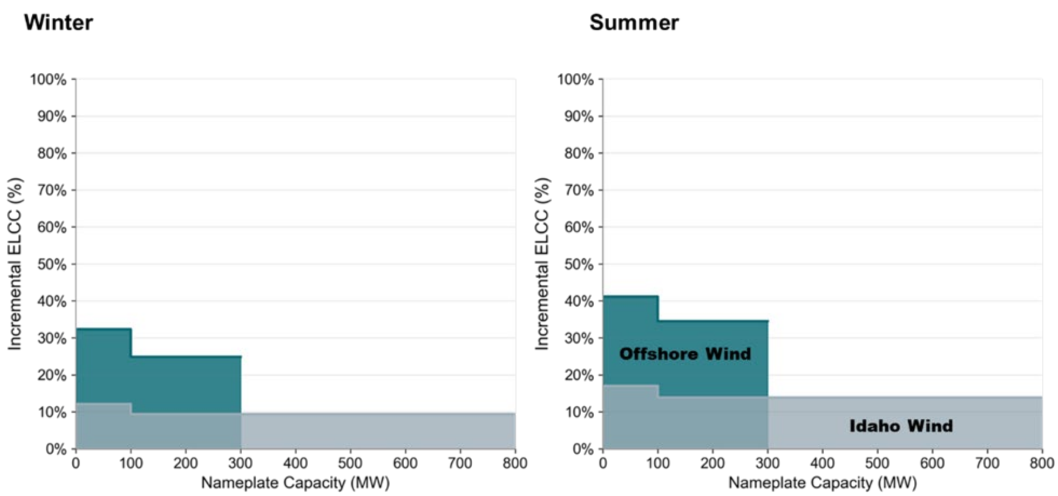
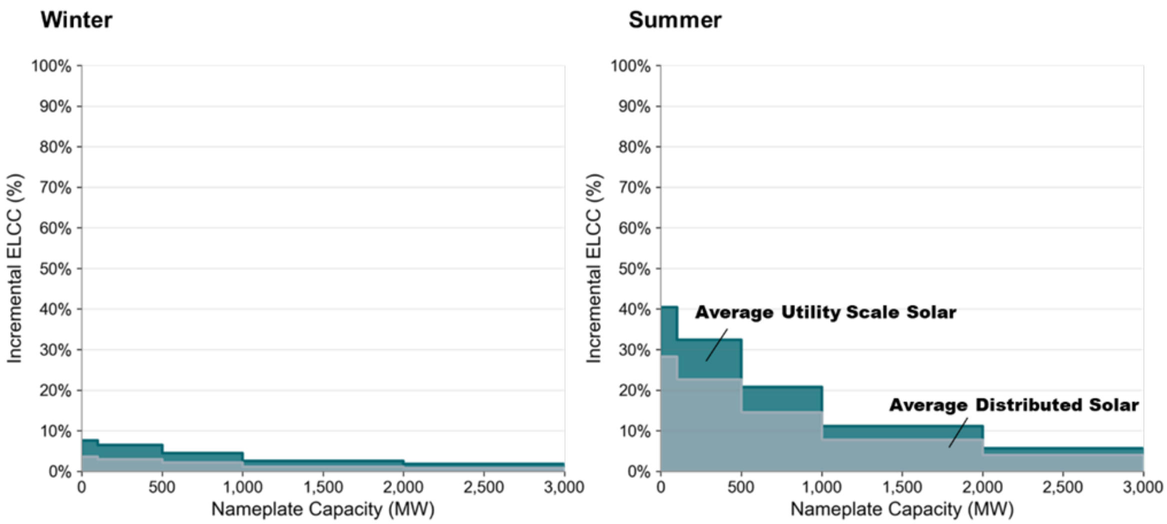


Figure L.13 shows the average winter and summer ELCC saturation curves for utility-scale solar (comprised of Idaho Solar, Washington East Solar, Washington West Solar, Wyoming East Solar, and Wyoming West Solar) and distributed solar (comprised of Distributed Ground Mount Solar and Distributed Rooftop Solar). Utility-scale and distributed solar are in the same resource group, so the overall penetration of solar resources determines the ELCC saturation for each solar resource. E3 calculated the ELCC for five tranches for Solar: 0–100 MW, 100–500 MW, 500–1,000 MW, 1,000–2,000 MW, and 2,000–3,000 MW.

The ELCC for solar is already very low in winter, so the ELCC saturation effect does not have as much impact in winter. On the other hand, the ELCC for solar in summer starts relatively high and then declines rapidly at higher penetration levels. The ELCC begins high because solar generation generally coincides nicely with periods of high energy demand in summer — when air conditioning loads are high — and because PSE's resource portfolio does not have high solar penetration.

At higher penetration levels, the ELCC for incremental solar is much lower. For example, the ELCC for the first tranche of utility-scale solar is 40 percent in summer, but the ELCC for the 2,000–3,000 MW tranche is only six percent in summer. If PSE had 2,000 MW of additional solar in its resource portfolio, this solar would largely mitigate reliability concerns during daytime hours in summer but would not do anything to alleviate reliability concerns during nighttime hours. As a result of the reliability need being low during solar generation hours, the ELCC for additional solar beyond 2,000 MW is low.

Figure L.13: ELCC Saturation Curves for Solar Resources



Tables that list the ELCC for each resource as a function of penetration are in the next section. The values in these tables correspond to the values in the saturation curves earlier in this appendix. Each table contains the ELCC values for all resources within a resource group.

To understand how to interpret these tables, take Table L.6 as an example. E3 calculated the ELCC for three tranches: 0–100 MW, 100–1,000 MW, and 1,000–3,000 MW. For the 0–100 MW tranche, the ELCC of British Columbia Wind in winter is 34 percent. If we added 100 MW of this resource, the capacity contribution would be 34 percent x 100 MW = 34 MW. For the 100–1,000 MW tranche, the ELCC of British Columbia Wind in winter is 27 percent. If we added 1,000 MW of this resource, the capacity contribution of the 900 MW added beyond the first tranche would be 27 percent x 900 MW = 243 MW. The same logic applies to the 1,000–3,000 MW tranche.

Table L.6: ELCC by Tranche for Pacific Northwest Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	3,000
Winter	British Columbia Wind	34%	27%	16%
	Washington Wind	13%	11%	6%
Summer	British Columbia Wind	13%	11%	7%
	Washington Wind	5%	4%	3%

Table L.7: ELCC by Tranche for Rockies Wind

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
Winter	Montana Central Wind	39%	30%	19%
	Montana East Wind	32%	25%	16%
	Wyoming East Wind	52%	40%	26%
	Wyoming West Wind	39%	29%	19%
Summer	Montana Central Wind	27%	23%	18%

Season	Resource	Cumulative Capacity by Tranche (MW)		
		100	1,000	2,000
	Montana East Wind	19%	16%	13%
	Wyoming East Wind	34%	29%	23%
	Wyoming West Wind	34%	29%	23%

Table L.8: ELCC by Tranche for Idaho Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	800
Winter	12%	9%
Summer	17%	14%

Table L.9: ELCC by Tranche for Offshore Wind

Season	Cumulative Capacity by Tranche (MW)	
	100	300
Winter	32%	25%
Summer	41%	34%

Table L.10: ELCC by Tranche for Solar Resources

Season	Resource	Cumulative Capacity by Tranche (MW)				
		100	500	1,000	2,000	3,000
Winter	Idaho Solar	8%	7%	5%	3%	2%
	Washington East Solar	4%	4%	3%	1%	1%
	Washington West Solar	4%	3%	2%	1%	1%
	Wyoming East Solar	11%	10%	7%	4%	3%
	Wyoming West Solar	10%	8%	6%	3%	2%
	DER Ground Mount Solar	4%	3%	2%	1%	1%
	DER Rooftop Solar	4%	3%	2%	1%	1%
Summer	Idaho Solar	38%	30%	19%	10%	5%
	Washington East Solar	55%	44%	28%	15%	8%
	Washington West Solar	53%	42%	27%	15%	7%
	Wyoming East Solar	29%	23%	15%	8%	4%
	Wyoming West Solar	28%	22%	14%	8%	4%
	DER Ground Mount Solar	28%	23%	14%	8%	4%
	DER Rooftop Solar	28%	23%	15%	8%	4%

Table L.11: ELCC by Tranche for Storage Resources

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
Winter	Li-ion Battery (2-hour)	89%	80%	46%	30%	18%	17%	13%	13%	10%	10%
	Li-ion Battery (4-hour)	96%	96%	76%	42%	23%	19%	15%	15%	12%	12%
	Li-ion Battery (6-hour)	98%	98%	82%	68%	31%	21%	16%	16%	12%	12%
	Pumped Storage (8-hour)	99%	99%	94%	76%	43%	23%	17%	17%	14%	14%
Summer	Li-ion Battery (2-hour)	97%	80%	57%	42%	33%	30%	23%	23%	20%	20%

Season	Resource	Cumulative Capacity by Tranche (MW)									
		250	500	750	1000	1250	1500	1750	2000	2250	2500
	Li-ion Battery (4-hour)	97%	93%	93%	93%	59%	45%	31%	31%	17%	17%
	Li-ion Battery (6-hour)	98%	98%	98%	98%	89%	82%	32%	21%	15%	15%
	Pumped Storage (8-hour)	99%	99%	99%	99%	98%	92%	47%	24%	15%	15%

Table L.12: ELCC by Tranche for Storage Resources (Continue)

Season	Resource	Cumulative Capacity by Tranche (MW)									
		2750	3000	3250	3500	3750	4000	4250	4500	4750	5000
Winter	Li-ion Battery (2-hour)	10%	10%	8%	8%	8%	8%	6%	6%	6%	6%
	Li-ion Battery (4-hour)	12%	12%	9%	9%	9%	9%	7%	7%	7%	7%
	Li-ion Battery (6-hour)	12%	12%	10%	10%	10%	10%	8%	8%	8%	8%
	Pumped Storage (8-hour)	14%	14%	11%	11%	11%	11%	9%	9%	9%	9%
Summer	Li-ion Battery (2-hour)	20%	20%	16%	16%	16%	16%	10%	10%	10%	10%
	Li-ion Battery (4-hour)	17%	17%	10%	10%	10%	10%	8%	8%	8%	8%
	Li-ion Battery (6-hour)	15%	15%	11%	11%	11%	11%	9%	9%	9%	9%
	Pumped Storage (8-hour)	15%	15%	12%	12%	12%	12%	9%	9%	9%	9%

Table L.13: ELCC by Tranche for Demand Response Resources

Season	Resource	Cumulative Capacity by Tranche (MW)	
		100	**300**
Winter	Demand Response (3-hour)	69%	67%
	Demand Response (4-hour)	73%	72%
Summer	Demand Response (3-hour)	95%	87%
	Demand Response (4-hour)	99%	90%

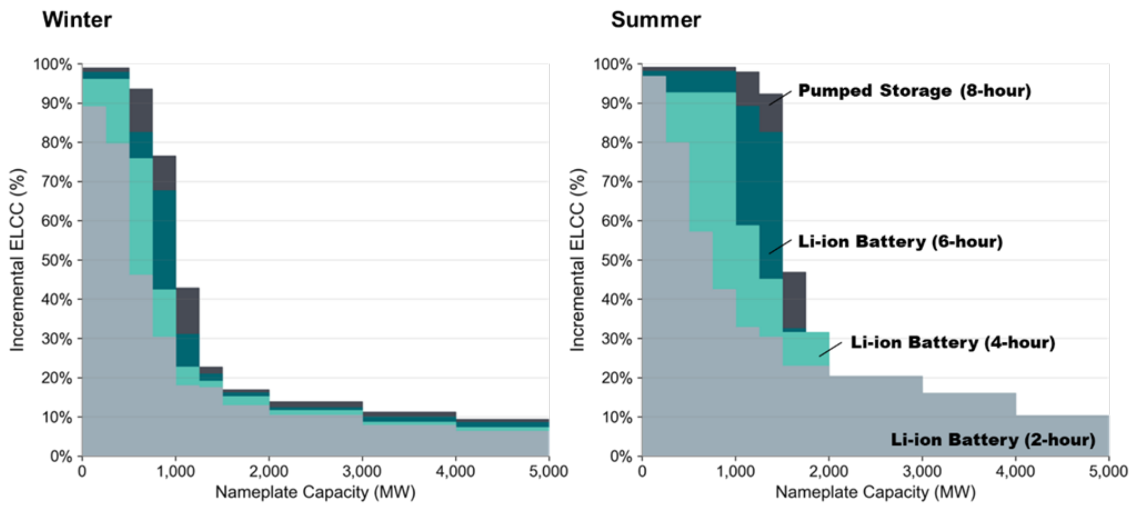
5.3. Generic Energy Storage ELCC Saturation Curves

E3 calculated ELCC saturation curves for each energy storage resource (see Figure L.14). Like other dispatch-limited resources, the ELCC of energy storage declines with increasing penetration levels. E3 calculated the ELCC for ten tranches for energy storage resources: 250–1,500 MW, 1,500–2,000 MW, and 1,000–5,000 MW. E3 calculated separate ELCC saturation curves for each individual energy storage resource.

The ELCC starts high and then declines at increasing penetration levels. The ELCC starts very high because energy storage is effective at supplying energy during a relatively short loss of load event. However, as we added more storage to the system, the net peak load (load minus renewable and storage generation) flattened, and the next tranche of storage must discharge over a longer period to help satisfy the new net peak lead. The ELCC declines more rapidly in winter than in summer. The ELCC starts falling rapidly after approximately 500 MW in winter and 1,000 MW in summer because the net peak load in summer is narrower than in winter. Limited duration energy storage can provide more reliability value in summer because power demand is high for shorter periods relative to winter.

The ELCC saturation curve declines more slowly for longer-duration energy storage. For example, in summer, Pumped Storage (8-hour) has an ELCC greater than 90 percent for the 1,250–1,500 MW tranche, while Lithium-ion Battery (2-hour) has an ELCC of 30 percent for the same tranche. The ELCC for longer-duration storage declines slower because it can discharge longer. As the net peak load flattens and storage must discharge over longer periods, a storage resource with eight hours can discharge at a higher level than a storage resource with only two hours. This does not necessarily mean shorter-duration energy storage is only valid up to a certain penetration level. The selection of different energy storage resources ultimately depends on their relative economics, which depends on the ELCC and other factors, such as resource costs and value from balancing system generation. The portfolio analysis assesses all of these factors together.

Figure L.14: ELCC Saturation Curves for Storage Resources



5.4. Generic Hybrid Resources

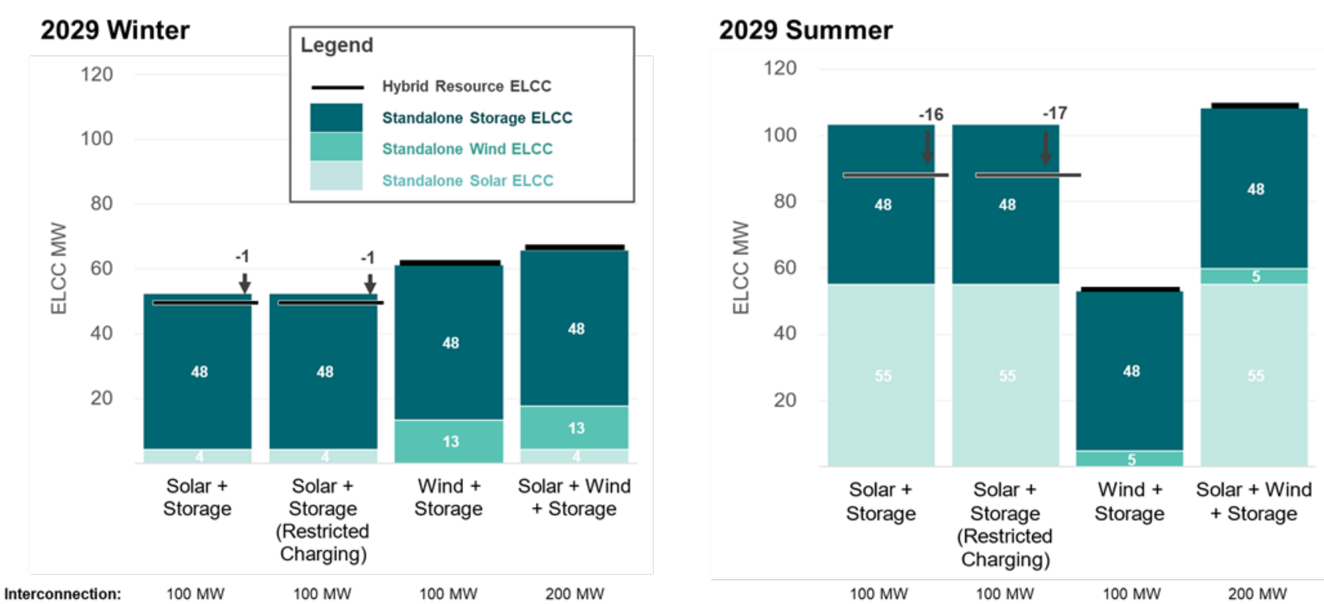
E3 modeled the ELCC of four types of hybrid resources (see Table 7.13 in Chapter Seven: Resource Adequacy Analysis) on behalf of PSE. We assumed we would site these hybrid resources in Washington. The solar resource corresponds to Washington East Solar, the wind resource corresponds to Washington Wind, and the storage resource corresponds to Lithium-ion Battery Storage (4-hour). For each hybrid resource, we assumed the renewable and storage resources would share the same interconnection. If the interconnection capacity is less than the capacity of the renewables plus the storage capacity, then this could limit how much power a hybrid resource can provide to PSE's system during some hours. Project developers often locate hybrid resources behind the same interconnection to reduce costs. For the Solar + Storage (Restricted Charging) resource, the battery storage resource can only charge from onsite renewable energy. The battery storage resource can charge from onsite renewable energy or the grid for other hybrid resources.

Figure L.15 shows the ELCC results for the hybrid resources. The figure provides the ELCC for each hybrid resource (black line) and compares this to the sum of the ELCCs for the individual resources that make up the hybrid resource (stacked bars).

Figure L.15 notes three major findings. First, the Wind + Storage and Solar + Wind + Storage resources have the same ELCCs as the sum of the ELCCs for the individual resources. This similarity indicates that the interconnection limits for these resources are not binding during times of reliability need. Second, as opposed to the hybrid wind resources, the two Solar + Storage resources have lower ELCCs than the sum of the ELCCs for the individual resources, especially in summer.

The lower ELCCs for Solar + Storage indicates that the interconnection limits for these resources are binding during times of reliability need. During summer peak loads, the solar output is relatively high. When this is the case, it limits the amount of storage that can be discharged to serve reliability needs, as the interconnection is only 100 MW. Lastly, the charging restriction for the Solar + Storage resource does not significantly impact the ELCC for the resource because, most of the time, there is sufficient energy from the solar project to charge the battery between reliability events.

Figure L.15: ELCC for Hybrid Resources



5.5. Generic Natural Gas Resources

In addition to calculating the ELCC of dispatch-limited resources, E3 also calculated the ELCC of three types of generic natural gas resources (see Table 7.14 in Chapter 7: Resource Adequacy Analysis). Three factors influence the capacity contribution of these resources: ambient temperature derates, forced outage rates, and unit size.

PSE determined the capacity ratings of these units by season using the same ambient temperatures used for existing natural gas plants. The summer rating is lower than the winter rating for combined cycle and frame turbine units. There is no derate in summer for reciprocating engines.

The ELCC for these natural gas resources is less than 100 percent because of forced outages. There is a chance that a unit is on forced outage when the PSE system needs the resource to ensure reliability. The assumed forced outage rates are 3.88 percent for combined cycle units, 2.38 percent for frame turbine units, and 3.30 percent for reciprocating engines.

The forced outage rates and the unit sizes influence the ELCC results. The higher the forced outage rate, the greater the chance the unit is on outage when needed and the lower the ELCC. If the unit is large, then this will result in a lower ELCC because, when a larger unit is on forced outage (e.g., 367 MW combined cycle plant), this has a greater chance of causing reliability problems for PSE's system than if a smaller unit is on forced outage (e.g., 18 MW reciprocating engine).

The ELCC for the combined cycle is lower because it has the highest forced outage rate and the largest unit size. The ELCC for a frame turbine unit is similar to the ELCC of a reciprocating engine. Although the forced outage rate for a frame turbine unit is smaller, the unit size is larger. These factors largely offset each other. The ELCC percent values are higher in summer for combined cycle and frame turbine units because the rated capacities are lower than in winter; in other words, the unit size is smaller.

6. Compared: the 2023 Electric Report and the 2021 Integrated Resource Plan

This section compares the results of the 2023 Electric Report with the results from the 2021 IRP. Because we made many updates to the inputs and methodology in the 2023 Electric Report, there are meaningful changes to several key outputs of the resource adequacy analysis.

6.1. Planning Reserve Margin

See Table L.14 for a comparison between the PRM in the 2021 IRP and the 2023 Electric Report.

Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, we can think of the results for the 2021 IRP as akin to the winter results for the 2023 Electric Report. Comparing the results from the 2021 IRP to the 2029 winter results from the 2023 Electric Report shows that the capacity contributions of resources are similar (5,062–5,072 MW in the 2021 IRP and 5,047 MW in the 2023 Electric Report). The median peak load is also similar (4,949–5,199 MW in the 2021 IRP and 5,004 MW in the 2023 Electric Report. The additional perfect capacity need for 2029 in the 2023 Electric Report falls between 2027 and 2031 in the 2021 IRP.

The PRM for the 2023 Electric Report (26 percent) is higher than that of the 2021 IRP (20–24 percent). One of the main reasons for this discrepancy is that the 2023 Electric Report shows an increased risk of loss of load in the summer, whereas the 2021 IRP shows little to no risk of loss of load in the summer. Because the 2023 Electric Report shows a much greater risk of loss of load in the summer, we must ensure the risk of loss of load in winter is meaningfully less than five percent to ensure an annual LOLP of five percent. To achieve this, we need more resource capacity in winter. Because the 2021 IRP shows little to no risk of loss of load in summer, we do not need this additional buffer in winter.

Because of the preceding reasons, the 2021 IRP results are not directly comparable to the 2023 Electric Report results for the summer. The differences between the 2021 IRP results and the 2023 Electric Report results for summer are similar to the reasons for the differences between the 2023 Electric Report results for winter and 2023 Electric Report results for summer, which we discussed in the Resource Adequacy Inputs and Updates Section.

Table L.14: Compared: PRM in the 2021 IRP and the 2023 Electric Report (MW)

Resource	2027[1]	2031[1]	2029 Winter[2]	2034 Winter[2]	2029 Summer[2]	2034 Summer[2]
Natural Gas	2,050	2,050	2,050	2,050	1,688	1,688
Mid-C Hydroelectric	560	560	560	560	560	560
Wind, Solar, Baker, Other Contracts	981	989	997	981	244	252
Market Purchases	1,471	1,473	1,440	1,434	961	751
Additional Perfect Capacity Need	907	1,381	1,272	1,746	1,875	2,856
Total Resource Need	5,969	6,453	6,319	6,771	5,329	6,107
Normal Peak Load	4,949	5,199	5,004	5,382	4,171	4,831
Planning reserve margin	20%	24%	26%	26%	28%	26%

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report

6.2. Generic Wind and Solar Resources

See Table L.15 for a comparison between the renewable resource ELCC values in the 2021 IRP and the 2023 Electric Report. The 2021 IRP did not model British Columbia wind. The ELCC for Idaho wind is lower in the 2023 Electric Report because the profile from DNV indicates a significantly lower generation than the profile used for the 2021 IRP. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC results from the 2021 IRP are akin to the winter ELCC from this report. The ELCCs differ due to changes in the resource profiles and the timing of the loss of load events.

For solar resources, the ELCC results in the 2021 IRP are generally lower than the winter ELCC results in this report. In the 2021 IRP, loss of load events were usually longer and, in some cases, spanned multiple days. As a result, many loss of load events spanned nighttime hours when solar generation is lower or nonexistent. In this report, by contrast, loss of load events do not span the entire day or multiple days. Most loss of load hours are during daytime hours when solar output would be higher. As a result, the winter ELCC results in this report are higher than the ELCC results in the 2021 IRP.

Table L.15: Compared: Wind and Solar ELCCs in 2021 IRP and 2023 Report (First Tranche: 100 MW)

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
British Columbia	Wind	-	-	34	13
Idaho	Wind	24	27	12	17
Montana Central	Wind	30	31	39	27
Montana East	Wind	22	24	32	19
Offshore	Wind	48	46	32	41
Washington	Wind	18	15	13	5

Resource	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Wyoming East	Wind	40	41	52	34
Wyoming West	Wind	28	29	39	34
DER Ground Mount	Distributed Solar	1	2	4	28
DER Rooftop	Distributed Solar	2	2	4	28
Idaho	Utility-scale Solar	3	4	8	38
Washington East	Utility-scale Solar	4	4	4	55
Washington West	Utility-scale Solar	1	2	4	53
Wyoming East	Utility-scale Solar	6	5	11	29
Wyoming West	Utility-scale Solar	6	6	10	28

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report

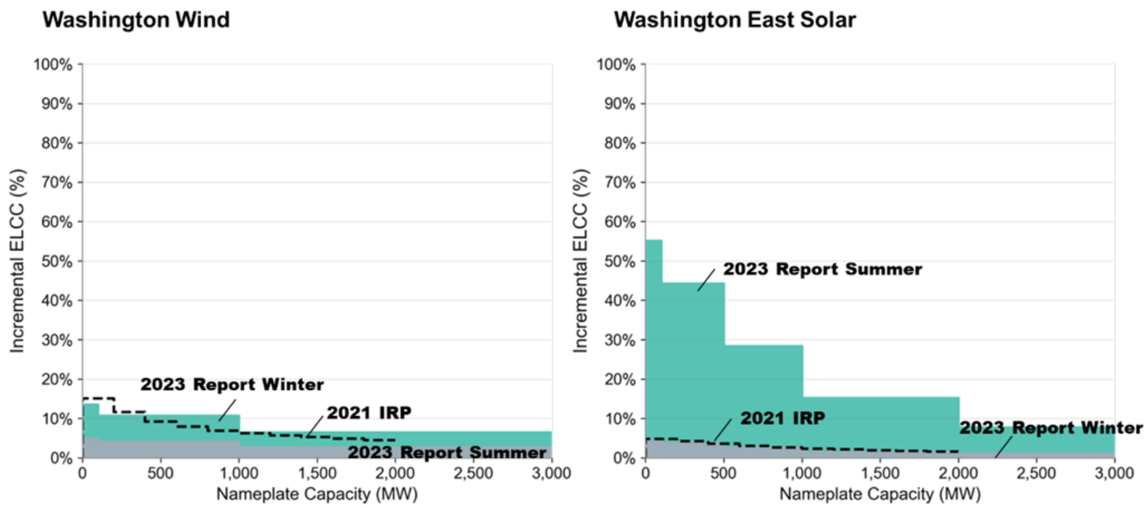
6.3. Generic Wind and Solar ELCC Saturation Curves

Figure L.16 compares the ELCC saturation curves in the 2021 IRP and the corresponding ELCC saturation curves in the 2023 Electric Report. The 2021 IRP included saturation curves for Washington wind and Washington East Solar through 2,000 MW, while the 2023 Electric Report E3 calculated saturation curves through 3,000 MW. The 2021 IRP calculated annual saturation curves, while the 2023 Electric Report E3 calculated separate saturation curves for winter and summer.

The results for Washington wind are similar. The ELCC in the 2021 IRP is similar to the winter ELCC in the report at lower penetration levels. At higher penetration levels, the ELCC in the 2021 IRP is between the winter ELCC and summer ELCC values.

The results for Washington East Solar are similar for winter but not summer. Because the 2021 IRP showed much greater capacity shortfalls in winter than in summer, the ELCC from the 2021 IRP can be considered akin to the winter ELCC from the 2023 Electric Report. The two are very similar. As discussed earlier in this section, the summer ELCC in the 2023 Electric Report is much higher than the winter ELCC.

Figure L.16: Compared: ELCC Saturation Curves in 2021 IRP and 2023 Electric Report



6.4. Generic Storage and Demand Response Resources

Table L.16 shows the storage and demand response ELCC results for the 2021 IRP and the 2023 Electric Report. Overall, the ELCC results in the 2023 Electric Report are much higher than those in the 2021 IRP. For example, the range of ELCC values for the 2023 Electric Report is 69-99 percent across resources and seasons, while the range of ELCC values for the 2021 IRP is 12-44 percent across resources.

There are two main reasons why the 2023 Electric Report sees higher ELCCs than the 2021 IRP: First, while PSE remains a winter-peaking system, the magnitude, frequency, and duration of critical reliability periods have changed substantially. Specifically, the duration of critical reliability periods has shortened relative to the 2021 IRP. As a result, energy-limited resources such as energy storage and demand response can perform more similarly to a perfect capacity resource to ensure reliability, the biggest driver for higher ELCC values, as even short-duration resources now have relatively high ELCC values.

Second, we changed how we modeled energy storage resources in the 2023 Electric Report. Allowing energy storage resources to discharge at maximum capacity for their rated duration increases their capabilities relative to the 2021 IRP. Allowing energy storage resources to provide operating reserves without discharging also increases their capabilities relative to the 2021 IRP. Lastly, the 2023 Electric Report ensures that the NWPP Reserve Sharing Program provides the same value to PSE's system when modeling the ELCC of energy storage.

Table L.16: Compared: Storage and Demand Response ELCCs in 2021 IRP and 2023 2023 Electric Report (First Tranche)

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Lithium-ion Battery (2-hour)	Storage	12	16	89	97
Lithium-ion Battery (4-hour)	Storage	25	30	96	97
Lithium-ion Battery (6-hour)	Storage	N/A	N/A	98	98

Resource[3]	Resource Type	2027[1] (%)	2031[1] (%)	2029 Winter[2] (%)	2029 Summer[2] (%)
Pumped Storage (8-hour)	Storage	37	44	99	99
Demand Response (3-hour)	Demand Response	26	32	69	95
Demand Response (4-hour)	Demand Response	32	37	73	99

Notes:

1. 2021 IRP
2. 2023 Electric Progress Report
3. Demand response first tranche is 100 MW. Storage first tranche is 250 MW.

6.5. Adjustments for Portfolio Analysis

Resource adequacy is an upstream study for the 2023 Electric Report. The resource adequacy analysis calculated planning reserve margin and resource ELCCs, modeled in the AURORA database to perform long-term expansion planning and hourly dispatch to optimize new builds and mimic the hourly operation of existing and new resources. Multiple tranches on resource ELCC add model complexity and increase run-time significantly. To manage the large-scale optimization problem run-time and meet the ERP study needs, we adjusted the planning reserve margin and resource ELCCs.

6.6. Planning Reserve Margin

We modeled three climate change load forecasts in the resource adequacy analysis to calculate the seasonal generation capacity needed to meet five percent LOLP. To calculate the planning reserve margin in percentage, we used the normal peak forecast in summer and winter and formulated the following equations:

$$\text{Planning Reserve Margin in Summer } \% = (\text{Generation Capacity Needs in Summer} - \text{Normal Peak Loads in Summer}) \,/\, \text{Normal Peak Loads in Summer X } 100\%$$

$$\text{Planning Reserve Margin in Winter } \% = (\text{Generation Capacity Needs in Winter} - \text{Normal Peak Loads in Winter}) \,/\, \text{Normal Peak Loads in Winter X } 100\%$$

The normal peak loads in summer and winter and the P50 load forecast of the average of the three climate change load forecasts are in Table L.17.

Table L.17: Peak Load

Load	Winter 2029	Winter 2034	Summer 2029	Summer 2034
Normal Peak Forecast (MW)	5,104	5,588	4,300	4,845
P50 Peak Load (MW)	5,004	5,382	4,171	4,831

6.7. Storage ELCC Tranches

In the resource adequacy analysis, we defined ten tranches to capture the storage ELCC saturation up to 5000 MW storage build, as shown in Figure L.14. The AURORA simulation shows a significant run-time requirement to dispatch storage with the ten tranches implemented in the model. Ten tranches are consolidated into three tranches to balance the complexity and accuracy of the storage saturation modeling, as shown in Table L.18.

Figure L.17: ELCC Saturation Curves for Storage Resources

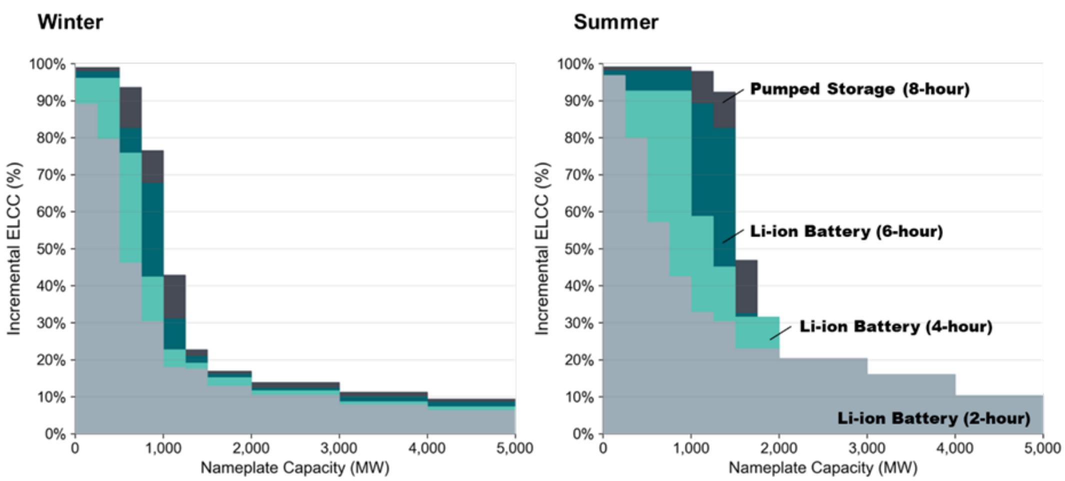
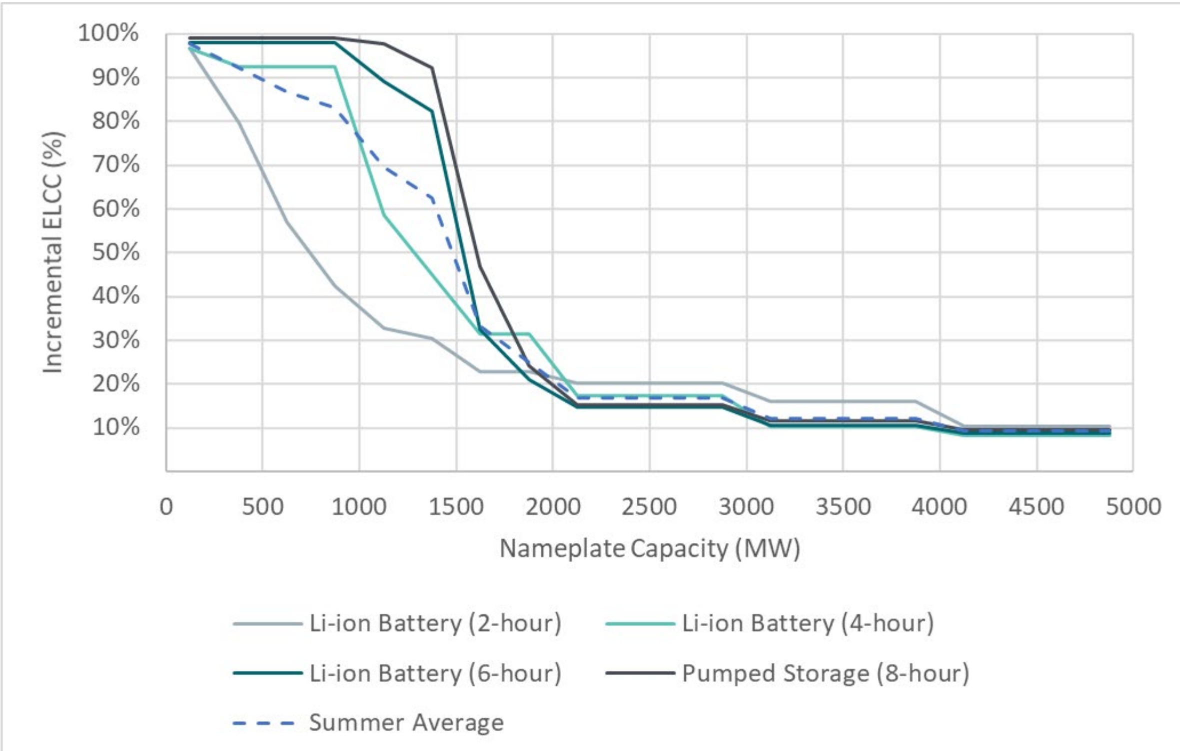


Table L.18: Storage ELCC Tranches in 2029

Resource	Season	ELCC 1 (%)	ELCC 2 (%)	ELCC 3 (%)
Li-ion Battery (2-hour)	Winter	61	18	9
Li-ion Battery (4-hour)	Winter	78	21	10
Li-ion Battery (6-hour)	Winter	86	26	11
Pumped Storage (8-hour)	Winter	92	33	12
Li-ion Battery (2-hour)	Summer	69	31	17
Li-ion Battery (4-hour)	Summer	94	52	15
Li-ion Battery (6-hour)	Summer	98	86	14
Pumped Storage (8-hour)	Summer	99	95	15
Cumulative Capacity by Tranche (MW)	Winter	1,000 MW	1,500 MW	5,000 MW
Cumulative Capacity by Tranche (MW)	Summer	1,000 MW	1,500 MW	5,000 MW

In the new tranches, 1000 MW and 1500 MW capacity are selected as points to break tranches to accommodate the saturation effects' trends and degree of accuracy. We used the summer curves to choose breakpoints since summer peak needs are more likely constrained.

Figure L.18: Storage ELCC Saturation Curves in Summer



6.8. Demand Response Tranches Consolidation

In the 2023 Electric Report, we estimate we could add up to 300 MW demand response to the portfolio. We defined two tranches in the resource adequacy analysis to catch the range of the potential builds, as shown in Figure L.19. The ELCCs in the second tranche do not reduce significantly from the ELCCs in the first tranches for winter and summer. The two tranches are consolidated into a single tranche to save the run-time of the AURORA simulation, as shown in Table L.19.

Figure L.19: ELCC Saturation Curves for Demand Response Resources

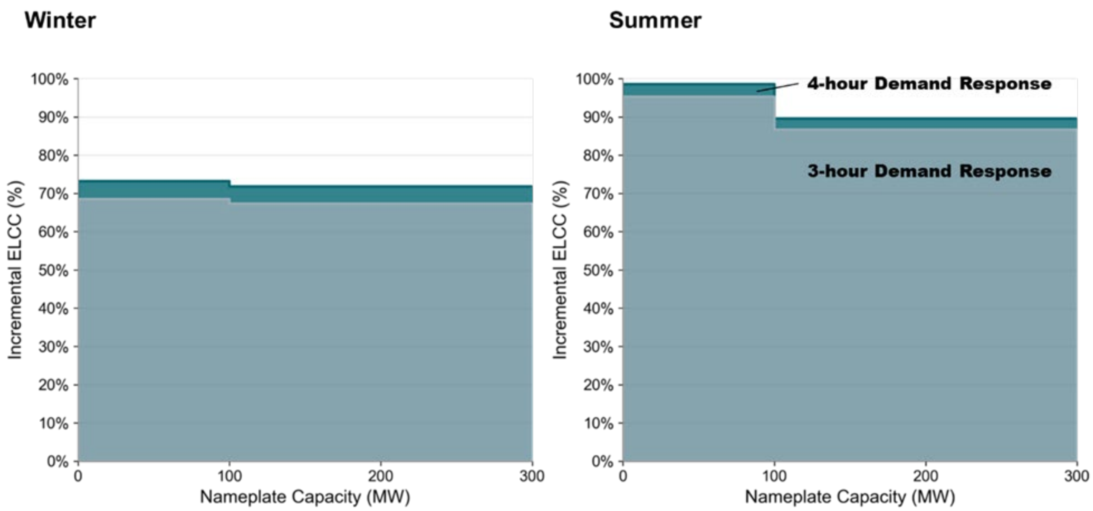


Table L.19: DR ELCC Tranches Consolidation — Incremental ELCC by Tranche in 2029

Resource	Season	1
Demand Response (3-hour)	Winter	68%
Demand Response (4-hour)	Winter	72%
Demand Response (3-hour)	Summer	90%
Demand Response (4-hour)	Summer	93%
Cumulative Demand Response	Winter	300 MW
Cumulative Demand Response	Summer	300 MW

6.9. Solar Tranches

The resource plan will build many renewable energy resources to meet the CETA needs. We calculated five-tranche ELCCs for wind and solar resources to capture the saturation effects in Figure L.10, Figure L.11, Figure L.12, and Figure L.13. The first three tranches cover the maximum builds for each wind resource group. Solar ELCCs go up to five tranches. We consolidated the five to three tranches to reconcile the run-time of the AURORA simulation and preserve the renewable resource ELCC saturation, as shown below in Table L.20.

Table L.20: Solar ELCC Tranches — Incremental ELCC by Tranche in 2029

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
DER Ground Mount Solar	Winter	4	3	1
DER Rooftop Solar	Winter	4	3	1
Idaho Solar	Winter	8	7	3
Washington East Solar	Winter	4	4	2
Washington West Solar	Winter	4	3	1
Wyoming East Solar	Winter	11	10	4

Resource	Season	Tranche 1 (%)	Tranche 2 (%)	Tranche 3 (%)
Wyoming West Solar	Winter	10	8	3
DER Ground Mount Solar	Summer	28	23	8
DER Rooftop Solar	Summer	28	23	8
Idaho Solar	Summer	38	30	10
Washington East Solar	Summer	55	44	15
Washington West Solar	Summer	53	42	14
Wyoming East Solar	Summer	29	23	8
Wyoming West Solar	Summer	28	22	7
Cumulative Resource	Winter	100 MW	500 MW	6,000 MW
Cumulative Resource	Summer	100 MW	500 MW	6,000 MW

6.10. Hybrid System ELCC Saturation

In the 2023 Electric Report, we modeled the following four hybrid systems as generic resources we could build:

- 100 MW Washington Solar East + 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 100 MW Washington Solar East Solar +50 MW 4-hour Li-ion Battery
- 100 MW Washington Wind + 50 MW 4-hour Li-ion Battery
- 200 MW Montana Wind Central + 100 MW 8-hour PHES

The hybrid ELCC and the sum of the standalone ELCC of each hybrid system are in Table L.21 and Table L.22.

Table L.21: Hybrid ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	51	87
Solar + Storage (Restricted Charging)	51	87
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

Table L.22: Sum of Standalone ELCC (MW)

Resource	Winter 2029	Summer 2029
Solar + Storage	52	103
Solar + Storage (Restricted Charging)	52	103
Wind + Storage	61	53
Solar + Wind + Storage	66	108
Wind + PHES	142	141

We calculated the saturation curves of each standalone renewable resource and storage resource in the RA study. We estimated the hybrid system ELCC saturation curves using the standalone resource ELCC saturations, as shown in Table L.23.

Table L.23: Hybrid Systems ELCC Tranches (MW) in 2029

Resource	Season	Tranche 1	Tranche 2	Tranche 3
Solar + Storage	Winter	40	11	5
Wind + Storage	Winter	49	15	5
Solar + Wind + Storage	Winter	51	16	5
Wind + PHSE Storage	Winter	142	33	12
Solar + Storage	Summer	61	28	6
Wind + Storage	Summer	51	28	7
Solar + Wind + Storage	Summer	77	36	7
Wind + PHSE Storage	Summer	141	95	15
Cumulative ELCC	Winter	1,000	1,500	5,000
Cumulative ELCC	Summer	1,000	1,500	5,000

7. Western Resource Adequacy Program Methodology

The Western Power Pool produced the methodology for the WRAP metrics.

➔ For details regarding their approach, please refer to this document on the WPP website.

7.1. Planning Reserve Margin

The planning reserve margin (PRM) measures the quantity of capacity needed above the median year peak load to meet the loss of load expectation (LOLE) standard, which serves as a simple and intuitive metric that can be utilized broadly in power system planning. The PRM is primarily determined on a system-wide basis.

We based the WRAP metrics on modeling completed with data from current Phase 3A participants. These metrics are only representative if the WRAP exists, has participants, and can share the load and resource diversity among participants as anticipated, if current participants move forward with the WRAP in the future, and if participants are subject to binding obligations to share diversity. Until this threshold is reached, participants will continue to assess circumstances and determine how to interpret modeling results and what reserve margins to keep.

We obtained the methodology for the PRM from the Western Power Pool in Section 2, Appendix C of the WRAP methodology document (2021-08-30_NWPP_RA_2B_Design_v4_final.pdf). We modeled the WRAP PRM footprint in two main subregions: Northwest (NW) and Desert Southwest / East (DSW/E).

The calculation for the allocation of the capacity requirement of the PRM follows:

$$Allocated\ capcity\ requirement = \left(\frac{Participant's\ P50\ Load}{\sum All\ Participant's\ P50\ Load}\right) \times regional\ capacity\ need$$

7.2. Qualifying Capacity Contributions

Table L.24, which can be found in the August 24, 2022, Resource Adequacy webinar, shows the methodology for resource capacity accreditation.

Table L.24: WRAP Qualifying Capacity Contributions

Resource Type	Accreditation Methodology
Wind and Solar Resources	Effective Load-Carrying Capability (ELCC) analysis
Run-of-river Hydroelectric	Average monthly output on capacity critical hours (CCHs)
Storage Hydroelectric	The WPP-developed hydroelectric model that considers the past 10 years of generation, potential energy storage, and current operational constraints
Thermal	Unforced capacity (UCAP) method
Short Term Storage	ELCC analysis (recent update — to be completed next model run)
Hybrid Resource	Sum-of-parts method where energy storage will use ELCC, and the generator will use the appropriate method as outlined
Customer-side Resources	Can register as a load modifier or as a capacity resource

7.3. WRAP Solar ELCC Zones

The WRAP footprint is comprised of two zones for solar resource ELCC modeling. Zone 1 contains the Northern states in the West, including Washington, Oregon, Idaho, Montana, and Wyoming. Zone 2 includes the Southern states in the West, such as California, Nevada, Utah, and Arizona. The allocation of ELCCs within each zone is based on the average monthly output of CCHs, which is anticipated to capture the time zone and geographic (East/West) diversity of resources. For solar ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. We can adjust the allocation of zonal ELCC to individual resources as the actual production data is accumulated.

Figure L.20 depicts the solar zones which can be found in the August 24, 2022, Resource Adequacy webinar.

Figure L.20: WRAP Area and Solar Zones

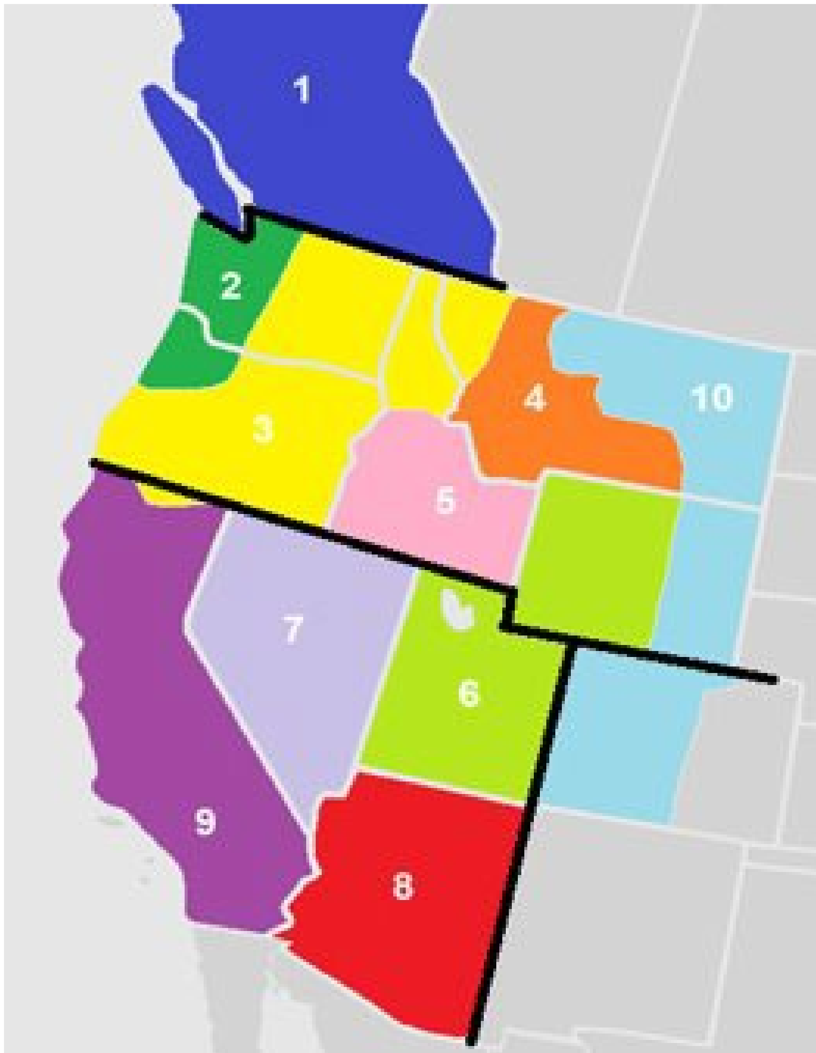


Table L.25: WRAP Solar ELCCs

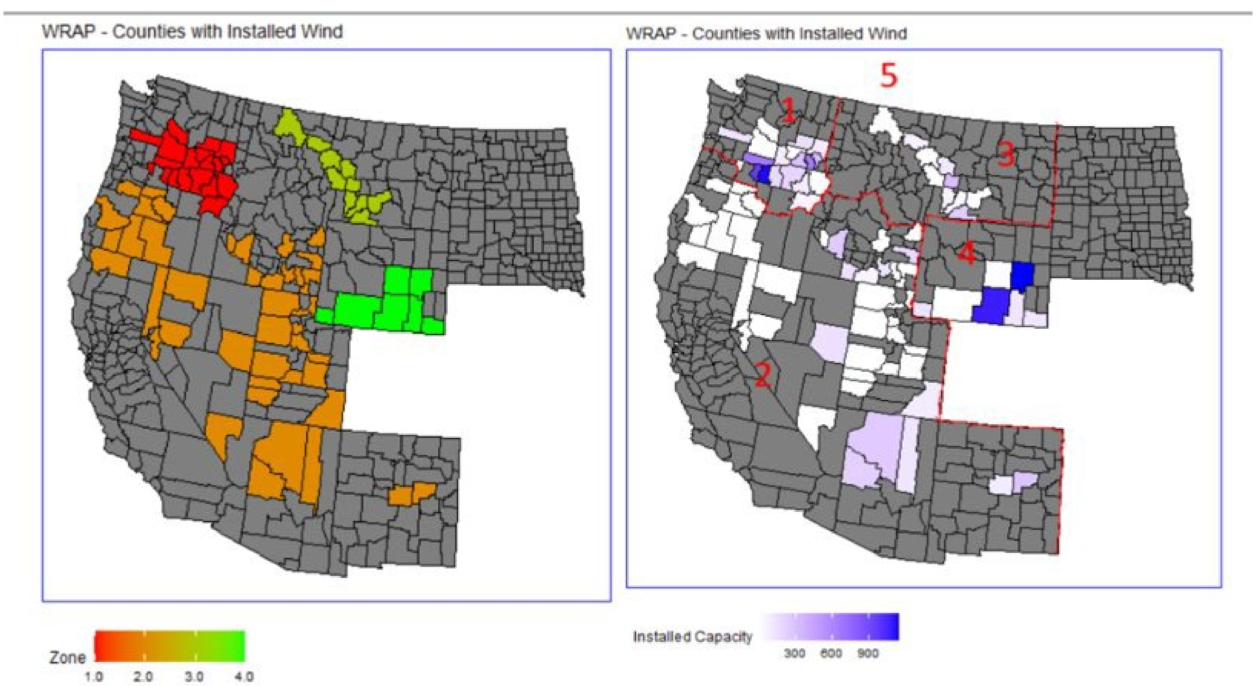
Zone	Nameplate (MW)	Winter 2023-2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (North)	2,138	2	3	3	4	5	23	30	24	13
2 (South)	9,024	3	5	7	7	5	16	24	23	11

7.4. WRAP Wind ELCC Zones

The WRAP footprint includes five wind ELCC zones. Zone 1 models the Columbia Gorge, spanning Southern Washington and Northern Oregon. Zone 2 comprises all other U.S. installed wind, including everything but the Columbia Gorge, Montana, and Wyoming. Zone 3 includes Montana, Zone 4 is Wyoming, and Zone 5 models British Columbia. For wind ELCC calculations, the historical average hourly net power output analysis utilizes at least three years of data, if available. The allocation of zonal ELCC to individual resources may be adjusted as the production data is accumulated.

Figure L.21 shows the WRAP counties with installed wind and their associated zone and capacity from the August 24, 2022, Resource Adequacy webinar.

Figure L.21: WRAP Counties with Installed Wind[10]



[10] https://www.westernpowerpool.org/private-media/documents/2021-12-21_RAPC_Minutes.pdf

Table L.26: WRAP Wind ELCCs

Zone	Nameplate (MW)	Winter 2023–2024					Summer 2024			
		Nov. (%)	Dec. (%)	Jan. (%)	Feb. (%)	Mar. (%)	Jun. (%)	Jul. (%)	Aug. (%)	Sep. (%)
1 (WA+)	5,734	10	9	8	11	13	19	22	18	13
2	2,400	32	30	28	32	34	18	18	16	16
3 (MT)	1,378	30	29	28	23	25	13	12	13	14
4 (WY)	2,429	36	32	30	27	31	15	16	14	14
5 (BC)	747	29	28	23	24	22	18	17	21	22