Planning Commission
Regular Meeting
December 2, 2025 - 7:00 PM
City Hall Council Chambers

AGENDA

PUBLIC PARTICIPATION

A. The Planning Commission Meeting scheduled for Tuesday, December 2, 2025, at 7:00 p.m. will be held in person and virtually.

Virtual Participation Link:
To listen to the meeting by phone or Zoom, please call the number below or click the link:
Phone one-tap:
+12532158782,,82909503829# US (Tacoma)
+12532050468,,82909503829# US
Join via audio:
+1 253 215 8782 US (Tacoma)
+1 253 205 0468 US
888 475 4499 US Toll Free
Webinar ID: 829 0950 3829
Zoom: https://us06web.zoom.us/j/82909503829

CALL TO ORDER

ROLL CALL

PLEDGE OF ALLEGIANCE

PUBLIC COMMENT

This is the place on the agenda where the public is invited to speak to the Board on any issue.

A. Comment from the audience on any proposal for action by the Commission. If the comment is related to an action subsequently listed here as a public hearing, the comment should be provided at the time of the public hearing.

The public can participate in-person or submit written comments in advance. Participants can submit written comments via mail, fax, or email. All written comments must be received prior to 5:00 p.m. on the day before the scheduled meeting and must be 350 words or less.

Please mail written comments to:
City of Auburn
Attn: Tammy Gallier, Administrative Specialist
25 W Main St

Auburn, WA 98001

Please fax written comments to:
Attn: Tammy Gallier, Administrative Specialist
Fax number: 253-804-3114

Email written comments to: planning@auburnwa.gov

If an individual requires accommodation to allow for remote oral comment because of a difficulty attending a meeting of the governing body, the City requests notice of the need for accommodation by 5:00 p.m. on the day before the scheduled meeting. Participants can request accommodation to be able to provide a remote oral comment by contacting the Community Development Department in person, by phone (253) 931-3090 or by email (planning@auburnwa.gov).

AGENDA MODIFICATIONS

APPROVAL OF MINUTES

A. October 21, 2025 Draft Minutes from the Special Planning Commission Meeting

OTHER BUSINESS

A. **Battery Energy Storage Systems & Development Regulations (Clark)**
Staff will introduce the Planning Commission to Battery Energy Storage Systems (BESS), how they operate, the regional needs, and the creation of development regulations.

B. **Co-Living Housing Code Update (Goode)**
Community Development Department will present on the implementation of RCW 36.70A.535 for co-living housing. Co-living housing means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building. This text amendment to Title 18 ACC will allow for the new use to be permissible in the R-3, R-4, R-NM, DUC, C-2, C-AG, and M-1 Zones and provides details on development standards for the new use.

PUBLIC HEARINGS

A. **Co-Living Housing Code Update (Goode)**
Public Hearing for public testimony and Planning Commission deliberation on the co-living housing text amendment to Title 18 ACC.

B. **2024 Downtown Subarea Plan Update (Teague)**
Public Hearing for public testimony and Planning Commission deliberation on the 2024 Auburn Downtown Subarea Plan, Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and associated subarea land use map and subarea zoning map amendments.

ACTION ITEMS

A. **Co-Living Housing Code Update (Goode)**
Planning Commission to take action on the co-living housing text amendment to Title 18 ACC.

B. **2024 Downtown Subarea Plan Update (Teague)**
Planning Commission to take action on the 2024 Auburn Downtown Subarea Plan, Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and associated subarea land use map and subarea zoning map amendments.

COMMUNITY DEVELOPMENT REPORT

ADJOURNMENT

The City of Auburn Planning Commission is a seven member advisory body that provides recommendations to the Auburn City Council on the preparation of and amendments to land use plans and related codes such as zoning. Planning Commissioners are appointed by the Mayor and confirmed by the City Council.

Actions taken by the Planning Commission, other than approvals or amendments to the Planning Commission Rules of Procedure, are not final decisions; they are in the form of recommendations to the City Council which must ultimately make the final decision.

CITY OF AUBURN WASHINGTON

AGENDA BILL APPROVAL FORM

Agenda Subject:
October 21, 2025 Draft Minutes from the Special Planning Commission Meeting

Meeting Date:
December 2, 2025

Department:
Community Development

Attachments:
10.21.25 Draft Minutes

Budget Impact:
N/A

Administrative Recommendation:

Background for Motion:

Background Summary:
See attached Draft Minutes

Councilmember:

Staff: Jason Krum

Planning Commission
Special Meeting
October 21, 2025 - 7:00 PM
City Hall Council Chambers

AMENDED

MINUTES

PUBLIC PARTICIPATION
The City of Auburn Planning Commission Meeting was held in person and virtually.

CALL TO ORDER
Chair Judi Roland called the meeting to order at 7:00 p.m. in the Council Chambers of Auburn City Hall, 25 West Main Street.

ROLL CALL
Commissioners present: Chair Judi Roland, Vice Chair William Stewart, Aaron Vanderpol, Lynn Walters, and Ajay Ganesan. Commissioner Julie Berry and Commissioner Kirk Hiller were excused.

Staff members present: Planning Services Manager Alexandria Teague, Senior Planner Dinah Reed, Senior Planner Alyssa Tatro, Planner II Gabriel Clark, Senior City Staff Attorney Chandra Hein, and Deputy City Clerk Rebecca Wood-Pollock.

PLEDGE OF ALLEGIANCE
Chair Roland led those in attendance in the Pledge of Allegiance.

AUDIENCE PARTICIPATION
No one came forward to speak.

APPROVAL OF MINUTES

A. September 16, 2025 Draft Minutes from the Special Planning Commission Meeting

Commissioner Vanderpol moved and Commissioner Walters seconded to approve the September 16, 2025, Special Planning Commission Meeting minutes.

MOTION CARRIED UNANIMOUSLY. 5-0

OTHER BUSINESS

A. **CAO Code Update Comments (Tatro/Teague)**
Discussion of the comments received up to date regarding the critical areas code update.

Manager Teague and Planner Tatro provided the Commission with an overview of the comments received from the Department of Ecology, Department of Natural Resources, Master Builders Association, and Department of Fish and Wildlife regarding the Critical Area Ordinance (CAO) Code Update.

Commission discussed stream impacts from property development, the Code Update process, stream buffers, and tree height and growth.

B. **Downtown Plan Follow Up Discussion (Teague)**
More in-depth discussion of the land use map change, zoning map change, and new DUC zoning districts associated with the Downtown Subarea Plan.

Manager Teague discussed details regarding the Downtown Subarea Plan, including a status update on the Plan, proposed Land Use Designation and Zoning changes, an overview of the districts, and the next steps in the process. She shared that the Public Hearing for this item is scheduled to be held on Wednesday, November 5th, 2025.

Commission discussed empty storefronts in the Downtown area, auto-oriented retail spaces, and long-term goals.

PUBLIC HEARINGS

A. **Auburn School District Comprehensive Map Amendment & Rezone (Reed)**
Public Hearing for the public testimony and Planning Commission deliberation on the Auburn School District Comprehensive Map Amendment & Rezone to change the land use designation for 15 parcels to Public/Quasi Public and to rezone the 15 parcels to P-1 Public Use District.

Chair Roland opened the Public Hearing at 7:46 p.m.
Planner Reed shared a presentation with the Commission on the Auburn School District Private-Initiated Land Use Map Amendment, including an overview of the Map Amendment and Staff recommendations.

Written Comments
City of Bonney Lake
The City of Bonney Lake submitted public comment in writing prior to the meeting which was shared with the Commission.

In-Person Comments
Jeff Grose, Auburn School District
Jeff provided public comment.

Commission discussed the public comment submitted by the City of Bonney Lake.

Chair Roland closed the Public Hearing at 7:55 p.m.

B. **2025 City Initiated Annual Amendments (Clark)**
The City of Auburn Planning Commission will hold a public hearing to receive testimony and conduct deliberations regarding the proposed 2025 City-Initiated Annual Amendments to the Comprehensive Plan. The scope of the amendments include:

- Adoption of Capital Facilities Plans for the Auburn, Dieringer, Federal Way, and Kent School Districts.
- Land Use Map Amendment: Redesignation of 23 parcels from Public/Quasi-Public to Residential Neighborhood Two.
- Technical Corrections to the Capital Facilities Element, Housing Element, and Housing Needs Assessment to address minor errors and improve clarity.
- Removal of the Core Plan as a reference document in the Comprehensive Plan update process.

Chair Roland opened the Public Hearing for the Adoption of Capital Facilities Plans for the Auburn, Dieringer, Federal Way, and Kent School Districts at 7:56 p.m.

Planner Clark shared a presentation with the Commission on the Adoption of Capital Facilities Plans for the school districts, including an overview of the plans and provided Staff recommendations.

No one came forward to speak.

Commission discussed new schools in Kent and Federal Way.

Chair Roland closed the Public Hearing at 8:00 p.m.

Chair Roland opened the Public Hearing for the Land Use Map Amendment at 8:01 p.m.

Planner Clark shared a presentation with the Commission on an overview of

the Comprehensive Land Use Map Update and provided Staff recommendations.

No one came forward to speak.

Chair Roland closed the Public Hearing at 8:02 p.m.

Chair Roland opened the Public Hearing for Technical Corrections to the Capital Facilities Element, Housing Element, and Housing Needs Assessment at 8:03 p.m.

Planner Clark shared a presentation with the Commission with an overview of the technical corrections, and provided Staff recommendations.

No one came forward to speak.

Commission discussed the action recommended to be taken by staff.

Chair Roland closed the Public Hearing at 8:05 p.m.

Chair Roland opened the Public Hearing for the Removal of the Core Plan at 8:05 p.m.

Planner Clark shared Staff recommendations of the removal of the Core Plan.

No one came forward to speak.

Chair Roland closed the Public Hearing at 8:07 p.m.

ACTION ITEMS

A. **Auburn School District Comprehensive Map Amendment & Rezone (Reed)**
Planning Commission to take action on the Auburn School District Comprehensive Map Amendment & Rezone to change the land use designation for 15 parcels to Public/Quasi Public and to rezone the 15 parcels to P-1 Public Use District.

Vice Chair Stewart moved and Commissioner Vanderpol seconded to recommend to City Council the adoption of the Auburn School District Comprehensive Map Amendment and Rezone as recommended by Staff.

MOTION CARRIED UNANIMOUSLY. 5-0

B. **2025 City Initiated Annual Amendments (Clark)**
Planning Commission to take action on the proposed 2025 City-Initiated Annual Amendments to the Comprehensive Plan. The scope of the amendments include:

- Adoption of Capital Facilities Plans for the Auburn, Dieringer, Federal Way, and Kent School Districts.
- Land Use Map Amendment: Redesignation of 23 parcels from Public/Quasi-Public to Residential Neighborhood Two.
- Technical Corrections to the Capital Facilities Element, Housing Element, and Housing Needs Assessment to address minor errors and improve clarity.
- Removal of the Core Plan as a reference document in the Comprehensive Plan update process.

Commissioner Walters moved and Commissioner Ganesan seconded to recommend to City Council the adoption of the Capital Facilities Plans for the Auburn, Dieringer, Federal Way, and Kent School Districts as recommended by Staff.

MOTION CARRIED UNANIMOUSLY. 5-0

Vice Chair Stewart moved and Commissioner Walters seconded to recommend to City Council the adoption of the Land Use Map Amendment as recommended by Staff.

MOTION CARRIED UNANIMOUSLY. 5-0

Vice Chair Stewart moved and Commissioner Ganesan seconded to recommend to City Council the recommendation of the text and calculation changes in the Housing Element and Housing Needs Assessment as recommended by Staff.

MOTION CARRIED UNANIMOUSLY. 5-0

Commissioner Walters moved and Commissioner Ganesan seconded to recommend to City Council the removal of the Core Plan as a reference document in the Comprehensive Plan update process.

MOTION CARRIED UNANIMOUSLY. 5-0

ADJOURNMENT
There being no further business to come before the Planning Commission, the meeting was adjourned at 8:08 p.m.

APPROVED this _____ day of _____, 2025

_____ _____
JUDI ROLAND, CHAIR Rebecca Wood-Pollock, Deputy City Clerk

CITY OF AUBURN WASHINGTON

AGENDA BILL APPROVAL FORM

Agenda Subject:
Battery Energy Storage Systems & Development Regulations (Clark)
Staff will introduce the Planning Commission to Battery Energy Storage Systems (BESS), how they operate, the regional needs, and the creation of development regulations.

Meeting Date:
December 2, 2025

Department:
Community Development

Attachments:
Memorandum, 1-PowerPoint Presentation, 2-King County Ordinance No. 19824, 3-SB5116 Clean Energy Transformation Act, 4-SB5126 Climate Commitment Act, 5-2021 PSE Integrated Resource Plan, 6-Ordinance No. 6978 , 7-Round Table Meeting Notes, 8-Ordinance No. 6995, 9-Outreach and Survey Materials, 10-PSE Model Ordinance, 11-WAC 51-54A1207 Electrical Energy Storage Systems, 12-Outline and Functions of the US Energy Grid, 13-PSC Energy Storage System Location Study

Budget Impact:
N/A

Administrative Recommendation:

Background for Motion:

Background Summary:
See attached Memorandum

Councilmember:

Staff: Jason Krum

CITY OF AUBURN WASHINGTON

MEMORANDUM

TO: Judi Roland, Chair, Planning Commission
Bill Stewart, Vice-Chair, Planning Commission
Planning Commission Members

FROM: Gabriel Cullins, Planner II
Department of Community Development

DATE: November 19th, 2025

RE: City File No. ZOA24-0004 – City of Auburn Battery Energy Storage Code Update

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I. INTRODUCTION AND PURPOSE

Battery Energy Storage Systems also known as BESS are systems of rechargeable batteries that help moderate the demand for electricity. During peak usage or extreme weather events, BESS can react quickly, providing additional electricity. In extreme cases BESS protect sensitive equipment such as transformers, transmission lines, switches and other infrastructure from overload preventing blackouts or long-term service outages.

BESS are found in a variety of instances and are scalable based on the need. On the smaller scale, they can be installed at private residences, or in larger scales constructed at a wastewater treatment plant or a hospital, to a stand-alone Commercial storage facility. In recent years the City observed a noticeable increase of private applications for the development of BESS within the City. When reviewing the proposals under existing standards, it was determined that Title 18 "Zoning" does not capture the true extent of these facilities. In response to the absence of applicable development standards, staff proposes to revise Auburn City Code to reflect the specific uses of these facilities. The scope of this code update is to satisfy three goals:

(1) Identify the purpose of the updates to Title 18.
(2) Identify regional approaches and standards for BESS.
(3) Determine appropriate land use approvals specific to Commercial BESS installations.



Figure 1 Residential BESS – Google


Figure 2 Accessory or Commercial BESS - Google



Figure 3 Commercial BESS – Google

Within the grid, there are four elements, (1) generation, (2) transmission, (3) distribution, and (4) consumption that need to be defined. This information was gathered from a report that defines the basic features of the grid and is viewable in Attachment 12.

(1) Generation occurs at established power generation facilities such as wind and solar stations located east of the Cascades and as far as Stillwater County, Montana.
(2) The electricity generated needs to travel from its source, to the location of demand. This can be over many hundreds of miles and requires high voltage transmission lines.
(3) When the high voltage electricity enters the region of demand (e.g. Auburn) it needs to be brought down to safe levels for distribution.
(4) Consumers, both residential and commercial, demand electricity, and demand can shift rapidly given the environmental conditions.

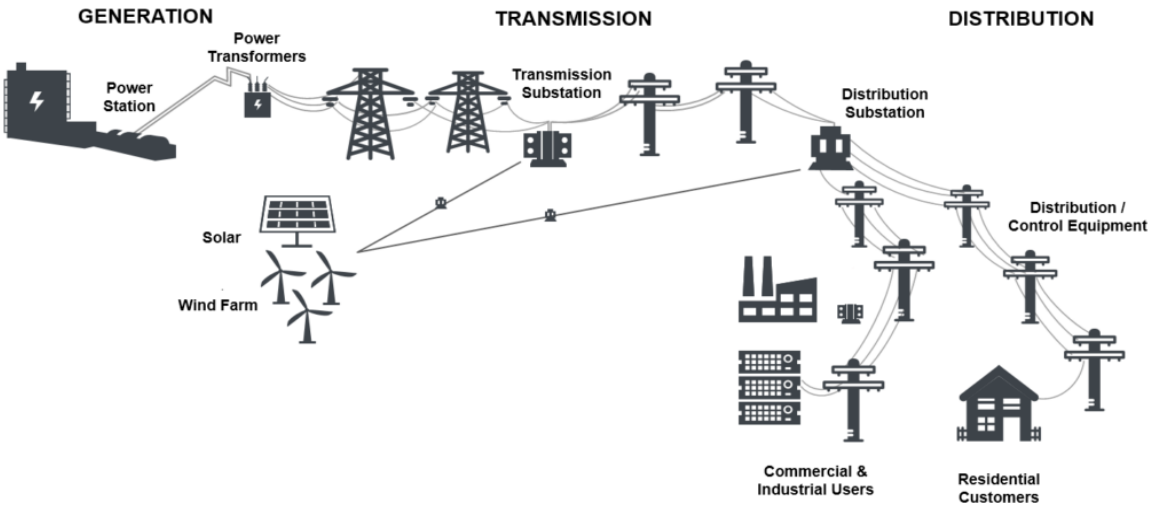


Figure 4 Overview of the Energy Grid

LEGISLATIVE ACTIONS AND INDUSTRY RESPONSES

Beginning in 2019, the Washington State Legislature passed a series of laws affirming the region's commitment to climate resiliency and reduction in carbon emissions.

- ***The Clean Energy Transformation Act (CETA) (SB 5116, 2019)*** - defines specific milestones which require the State's electricity supply to be free of greenhouse gas emissions by 2045. (Attachment 3)
- ***The Climate Commitment Act (CCA) (SB 5126, 2021)*** - established the cap-and-invest program, a market-based system that cost-effectively limits and lowers climate pollution and generates revenue for climate and air quality projects. (Attachment 4)

FUNDED BY WASHINGTON'S CLIMATE COMMITMENT ACT

As a result, of recent legislative action, the region's utility providers, heavy polluters, and local jurisdictions must work together to meet State climate initiatives. To address these goals, Puget Sound Energy (PSE) produced its first Integrated Resource plan (IRP) (Attachment 5) which identifies the regional needs, its shortcomings, and sectors of energy production to reduce impacts on its customers while reducing total carbon emissions.

Changes in the wholesale electricity market within the Western Interconnect (WI) means the region is tightening supply as customers require power from clean energy sources. The IRP explains the delicate balance that needs to be maintained as carbon emitting sources are closing, and clean options are coming online while maintaining consumer pricing and overall grid stability.

"Since 2016 nearly 15,000 MW of clean energy resources, namely intermittent wind and solar, and 500 MW of batteries have been added to the WI. At the same time, 12,000 MW of traditional dispatchable coal and natural gas resources have been retired or mothballed. (IRP, 1-6)"

As a result of a tightening supply, volatility has also increased. "On average, wholesale energy prices remain low in the Pacific Northwest. However, spikes in energy prices are becoming more frequent. "Notable events include the summer of 2018, when high regional temperatures coincided with forecasted outages at Colstrip, and March 2019, when regional cold temperatures coincided with reduced Westcoast Pipeline and Jackson Prairie storage availability. (IRP, 1-6)"

"Most recently, in August 2020, a western continental heatwave caused many entities in the region to take a range of actions from energy alerts to rolling blackouts. (IRP, 1-6)" To combat the future energy needs as the region transitions to clean energy sources, PSE has identified BESS as one of the six elements in the preferred energy portfolio. More information on the plan elements can be found in the IRP.

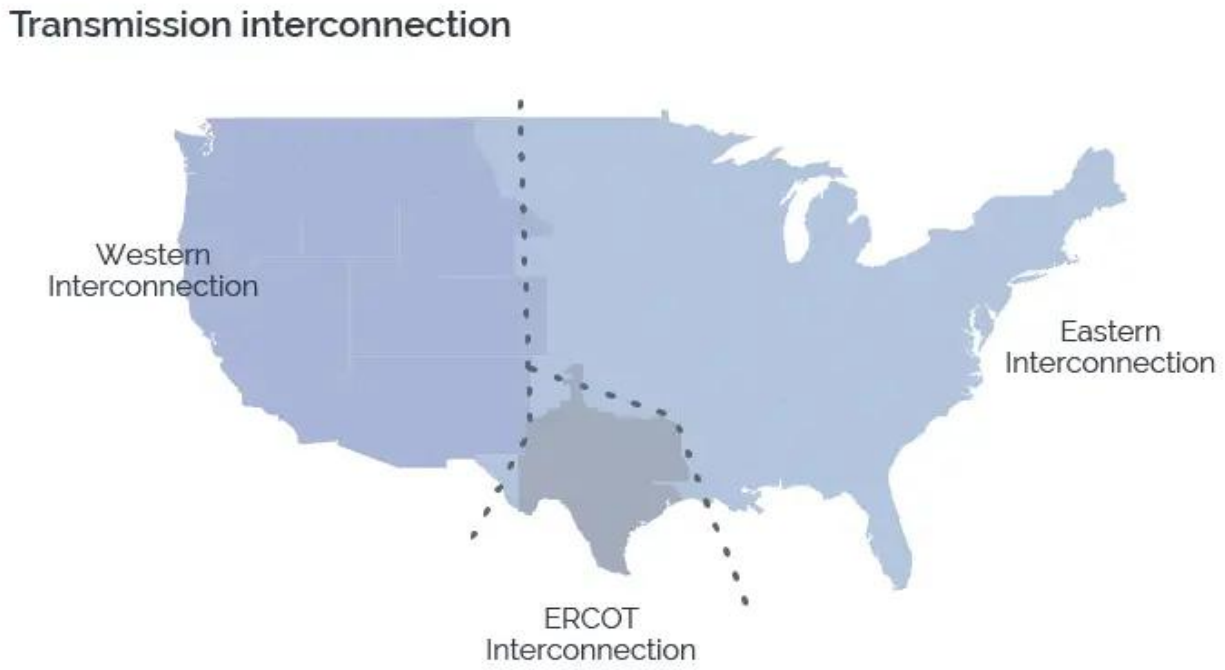


Figure 5 Transmission Interconnections in the United States - Google

The table on the following page shows a summary of the forecasted need for additional electrical sources in the preferred portfolio. The capacity of resource additions is measured in terms of peak hourly capacity over a planning horizon of 24 years.

Demand-side resources, including a broad suite of energy efficiency programs, are projected to free up approximately 1,757 MW of capacity that would otherwise be lost to inefficiencies. These gains may be supported by local and state policies promoting energy conservation and building performance standards.

In addition, customer-sited solar — including photovoltaic systems installed on rooftops and private properties — is expected to contribute 680 MW of planned capacity. These distributed solar installations enhance grid resilience and reduce demand spikes.

BESS accounts for 14% of total capacity resource additions in the distributed resource portfolio. Compared to large-scale generation facilities, BESS offers significantly greater responsiveness to fluctuating demand, enabling faster dispatch and improved grid flexibility.

Figure 1-4: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage Hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

Figure 6 Electric Preferred Portfolio - RFP

EXISTING LOCAL CONDITIONS

The Economic Development Element of the Comprehensive Plan describes Auburn as a proud blue-collar community; leading in manufacturing employment since the construction of the freight terminus for the Trans-Continental Railroad in the early 20th Century.

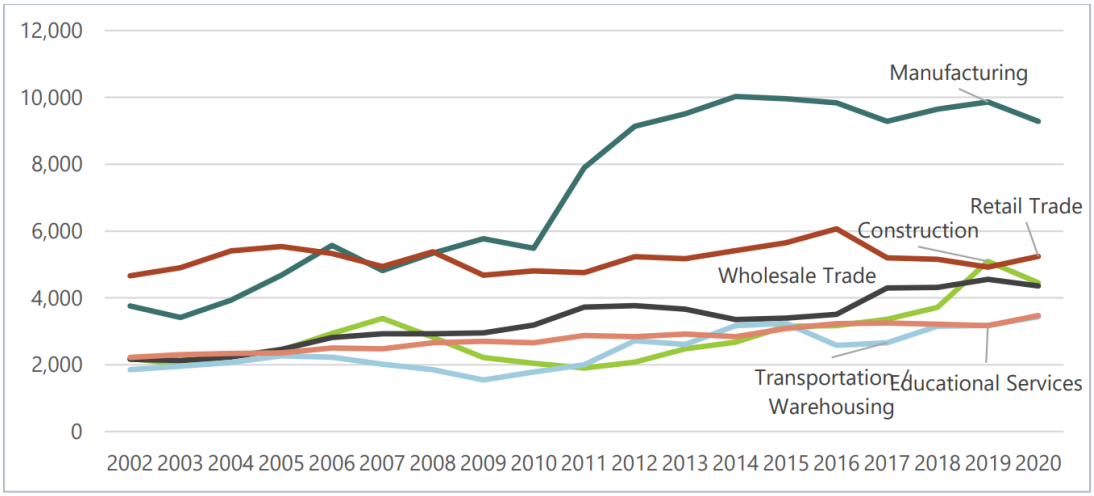


Figure 7 Top Industry Sectors in Auburn (2002-2020)

This momentum has not shifted as our community strength and core values continue to be reflected in our land use practices, and economic development achievements. Our residents are highly educated and experienced in manufacturing, construction, and wholesale trade and deserve to continue to be supported by policies that promote the rapidly changing construction and manufacturing industry. Figure 7 depicts the top industries by sector within the City.

The high concentration of the well-paying manufacturing and industrial jobs in the City reflects a job to unit of housing ratio at 1.48, which means the region benefits from the City's continued evolution as an employment center. As this relates to affordability, the City recognizes the need for attainable housing and has implemented land use and zoning changes to increase the capacity of housing throughout the City.

In alignment with the conditions identified in the PSE's IRP and supported by market analyses such as PSE's *Energy Storage System Location Study* (Attachment 13), the City acknowledges the growing need to accommodate Commercial BESS. Currently, Title 18 "Zoning" lacks a defined regulatory pathway for private developers or utilities to site, permit, and operate BESS facilities within City limits.

With the purpose of the updates to Title 18 now clearly established, the Department of Community Development is actively drafting new land use policies and zoning provisions to guide the responsible siting, construction, and operation of Commercial BESS infrastructure. These updates are designed to provide regulatory clarity, ensure compatibility with surrounding land uses, and support the City's broader goals for energy resilience and reducing carbon emissions.

A second key objective is to assess how jurisdictions across the State are regulating BESS facilities and in what land use contexts. By gathering and analyzing regional approaches, the City aims to ensure that proposed amendments to Title 18 are both reasonable and responsive to emerging needs. This comparative research will inform policy development and help position Auburn as a proactive and coordinated participant in the transition to distributed energy systems.

BESS MORATORIUM AND INDUSTRY ENGAGEMENT

To prevent uncoordinated or incompatible development in the absence of applicable standards, staff recommended that the Auburn City Council adopt a six-month development moratorium on the acceptance, processing, and approval of BESS applications. This temporary moratorium (see Attachment 6) allowed time to evaluate best practices, engage stakeholders, and establish a comprehensive zoning and permitting framework to support the safe and effective integration of BESS facilities within the City.

In October of 2025, staff organized a roundtable meeting with industry leaders to discuss the future of BESS in our community. A copy of the notes generated from the meeting has been provided as Attachment 7. To summarize the discussion:

(1) Labor unions representing construction trades were supportive of the City to continue to research these facilities as they provide expert technical training and experience.

(2) PSE provided information on the need for cities and counties to permit BESS in areas near existing infrastructure and expressed the deep need for grid stabilization that BESS can create.
(3) The Muckleshoot Tribe of Indians expressed their desire for microgrids and also shared concerns of potential environmental impacts related to fires and construction.
(4) Valley Regional Fire Authority also expressed concerns with fire hazards and clarified new state requirements in the International Fire Codes (IFC) Chapter 1207 and National Fire Protection Association (NFPA) Chapter 855.

To continue our research and planning efforts related to this topic, staff requested Council to consider a six-month extension to the moratorium. Which is set to expire at the beginning of May 2026. (See Attachment 8)

In early November, staff sent out a survey which included 101 community development offices throughout the State. The survey resulted in 10 responses, and 13 separate conversations on how each of the jurisdictions regulate BESS (see Attachment 9). The data collected shows BESS, when permitted, are subject to a variety of land use approvals. These approvals include Type II and Type III decisions and are typically applied to commercial and industrial land use designations, though there are several exceptions.

INDUSTRY RESULTS

The applicable zoning classification for BESS varied between cities and counties. Counties that permitted BESS, did so broadly, and allowed BESS to be installed alongside solar generation facilities in rural areas for example. In cities, additional land use approvals were required, and Commercial BESS is confined to the commercial and industrial zones of the cities if any industrial lands existed.

Another trend observed in the data was the definition of BESS. Some jurisdictions allow BESS to be included within “Substation or other Public Utility”, and other jurisdictions define BESS separately. While the code and its applications are unique to the jurisdiction that utilizes it, the City of Auburn intends to define BESS as a separate land use activity. The separate definition would direct these infrastructure investments in areas of the City that have existing supportive infrastructure and space where the potential visual, noise, and environmental impacts are consistent with existing zoning classifications.

CONFORMANCE OF COMMERCIAL BESS AND THE INTENT OF TITLE 18

Title 18 divides the City into zones where the location, height, setbacks, and use of buildings, the use of land, open space, and off-street parking and loading are regulated and restricted. These zoning regulations are established with reasonable consideration for the character and context of each district, including its suitability for specific land uses such as BESS. They reflect the City’s responsibility to balance the demonstrated need for such facilities with the common rights and interests of all property owners and the general public. The intent is to promote the most appropriate and beneficial use of land throughout the City, while preventing and mitigating potential public nuisances and ensuring long-term compatibility with surrounding uses.

While staff recognizes the opportunities and investment BESS may bring, the City wants to ensure development is orderly and reflects the intent of the Zoning Ordinance. The purpose of the Title is outlined in Section 18.02.030; Commercial BESS is described and how it meets or does not meet the purpose of this Title.

Purpose Statement	*Conformance with Title 18*
Provide adequate public facilities and services, including utilities, roads, schools, and parks in conjunction with development;	BESS provides emergency back-up generation during periods of black-outs or power outages allowing public facilities and services to continue to operate. This may include services such as City Administration, hospital operation, Fire Department Administration, or regional load shedding. In conjunction with residential development, BESS may pose development challenges. Depending on the proposal, BESS can occupy areas that would otherwise be used for residential purposes. To ensure BESS is able to meet the provisions of this Title, additional land use review will be required for specific zones. Figure 9 on page 10 of the staff memo outlines the information pertaining to project review types ensuring compatibility with the spirit and intent of each zoning classification.
Provide housing with essential light, air, privacy, and open space;	The zones determined to permit BESS will have specific regulations developed to ensure the projects will limit the impacts to light, air, privacy and open space of the City. The proposed revisions may include changes to setbacks, screening, and landscape standards.
Facilitate safe and efficient movement of traffic on the City's streets	Traffic impacts seen by Commercial BESS facilities may be felt during active construction, but would be negligible after the site is in operation. Maintenance and inspection teams would be the only of the few seen at the site during normal operation.
Stabilize and enhance property values	The argument that BESS decreases or improves property values is multifaceted and will be reviewed on a project by project basis. For example, a Commercial BESS project that conforms to the siting and use requirements of the applicable zone may not have as large of a potential negative impact to property values in the surrounding vicinity. This is compared to a Commercial BESS facility that is exposed and occupies a large portion of the site. While impacts vary by

	context, it is important to understand appropriate siting and use standards that can mitigate potential negative effects.
Facilitate adequate provisions for doing public and private business and thereby safeguard the community's structure upon which the prosperity and welfare of all depends	BESS, when meeting the adequate provisions of Title 18 can safeguard the community's structure upon which the prosperity and welfare relies on. Allowance of BESS and alternative energy systems can capture development and financial capital, furthering Auburn's manufacturing, construction, and administrative industries. These industries provide well-paying jobs and may aid the region in its transition to clean energy infrastructure.
Through such achievements, help ensure safety and security of home life. Foster good citizenship, and create and preserve a more healthful, serviceable, and attractive municipality and environment in which to live.	The proposed standards and use considerations would more closely align Commercial BESS facilities with the intent of the Title by reinforcing transparency, accountability, and public involvement. When community input is warranted, mechanisms such as public comment periods and educational open houses should be employed to ensure residents are informed and empowered to participate. These practices foster civic responsibility and encourage meaningful public discourse, strengthening the relationship between energy infrastructure and community values.

Figure 8 Alignment of BESS with Title 18

DEFINING THE THRESHOLD AND LAND USE APPROVALS OF BESS

Below is the City of Auburn's definition of accessory uses. Residences and commercial businesses may install BESS systems without land use approvals if, the system is below the defined threshold and meets the codified definition.

> *"Accessory Use" means a use, a building or structure, or part of a building or other structure which is subordinate to and the use of which is incidental to that of the main building, structure or use on the same lot, including a residential garage. If an accessory building is attached to the main building by a common wall or roof, such accessory building shall be considered a part of the main building. Parking areas will not be considered an accessory use under this definition. See related definitions for "Accessory use, manufactured home community" and "Accessory use, residential."*

King County has adopted a 2 MW threshold (see Attachment 2) to differentiate Accessory from Commercial BESS uses. In contrast, Auburn staff recommends that any BESS installation exceeding 1 MW of storage capacity—regardless of accessory status—be subject to a Type II or Type III decision process, or be prohibited outright. This lower threshold reflects Auburn's recognition of the potential scale, operational complexity, and land use impacts associated with larger BESS facilities. By requiring discretionary review and public notice, the City ensures that such installations are appropriately vetted for compatibility with surrounding uses and that residents have meaningful opportunities to engage in the siting process.

BESS ZONE COMPATIBILITY STAFF ANALYSIS

The following table presents a visual representation of the proposed zones and project permit decisions contained in Chapter 14.03 ACC applicable to Commercial BESS operations within the City. The use is analyzed further with the intent of each appliable zone. These determinations are not final and may be subject to change.

Zoning Classification	*Type I*	*Type II*	*Type III*	*Not Permitted*
Downtown Urban Center			X	
C-1, Light Commercial				X
C-2, Heavy Commercial		X		
I, Institutional			X	
M-1, Light Industrial	X			
M-2, Heavy Industrial	X			
LF – Airport Lading Field				X
OS – Open Space				X
P-1, Public Use			X	
R-1, Residential 1 DU/Acre				X
R-2, Residential Low				X
R-3, Residential Moderate				X
R-4, Residential High				X
R-NM Neighborhood Mixed Use				X
RC, Residential Conservancy				X
RF, Residential Flex				X
Planned Unit Development District (PUD)				X
R-MHC, Residential Mobile Home Community				X
Lakeland Hills PUD				X

Figure 9 Land Use Activity and Applicability Table

Downtown Urban Center

The intent of the Downtown Urban Center (DUC) Zone is to create a distinct and strong identity for downtown Auburn. The DUC Zone is intended to produce a concentration and mixture of commercial, office, medical, retail, residential, and civic uses that attract shoppers, visitors, and workers. Development that occurs within the downtown urban center zone often requires architectural and site design review which can be either Type I or Type II decisions made by staff.

While the physical form of BESS may not always align with the intended character of a zone particularly where space is typically reserved for shops, hotels, housing, or professional offices, there is a strong case for allowing BESS when serving institutional needs.

BESS can provide critical emergency and backup power to essential facilities such as hospitals, City Hall, and other public buildings that require uninterrupted power during outages. Without the option to site BESS in this area, these institutions would remain reliant on diesel generators,

which are noisy, emit air pollutants, and require regular fuel replacement every 6–12 months unless treated with stabilizers.

There are specific sites, and applications of BESS that require additional review and public input.

For these reasons, staff recommends Commercial BESS may be permitted in the DUC through the Type III decision process.

C-1, Light Commercial

Support for siting BESS within the C-1 Zone is limited due to land use priorities and compatibility concerns. Many C-1 parcels border low and moderate intensity residential zones and are intended to serve as local commercial businesses.

The purpose of the C-1 Zone is to promote a vibrant mix of small-scale, pedestrian oriented uses. BESS facilities are typically enclosed and occupy the full extent of the parcel, which can diminish the zone's ability to meet its intended character and functions.

For these reasons, Commercial BESS installations are recommended to be prohibited from the C-1 Zone.

C-2, Heavy Commercial

The C-2 Zone supports a broad range of medium to high intensity land uses. While the zone is primarily intended for retail, commercial, entertainment, and professional services, it also accommodates higher intensity uses such as low intensity industrial activities and utility infrastructure through additional land use approvals.

A significant portion of the zone is located along the valley floor West of Auburn Way which physically separates the C-2 Zoned parcels from a majority of the residentially zoned properties and remains underutilized. This area is well-suited for the development of BESS, offering both design flexibility and proximity to existing infrastructure.

For these reasons, staff recommends that Commercial BESS may be permitted in the C-2 Zone through the Type II decision process.

I – Institutional Zone

The Institutional Zone (I) is designed to support public-serving uses such as educational, cultural, and civic facilities. Distributed through the City, this zone meets both local and regional needs.

Historically, public and institutional facilities in this zone that require on-site power generation have relied on diesel generators. This mirrors the patterns seen in the DUC zone. However, diesel generators are noisy, polluting, and require frequent fuel replacement and maintenance.

For these reasons, staff recommends that Commercial BESS may be allowed in the I Zone through the Type III decision process.

M-1, Light Industrial and M-2, Heavy Industrial

The City's Industrial Zones are designed to accommodate a broad spectrum of industrial, manufacturing, and commercial activities. Residential uses are not permitted unless they are already established, ensuring that these zones remain focused to economic development and operational flexibility as outlined in the Comprehensive Plan.

The M-1 Zone supports industrial and commercial uses based on the nature of operations rather than the products produced such as warehousing and packaging. The M-2 Zone allows even greater flexibility, including activities that process raw materials and may have more substantial impacts on surrounding areas.

Given the purpose of these zones, the operational characteristics of BESS, and the presence of high-capacity transmission infrastructure, industrial areas are well suited for BESS installations. Impacts to nearby residents are minimal and unlikely to exceed those of existing permitted uses in the M-1 and M-2 Zones.

For these reasons, staff recommends that Commercial BESS be permitted outright in the M-1 and M-2 Zones.

LF – Airport Landing Field District

The Comprehensive Plan identifies airport hazards as threats to the safety of airport users and nearby properties. Obstruction-type hazards, in particular, can reduce the available area for aircraft to land, take off, and maneuver safely.

To protect public health, safety, and general welfare, it is essential to prevent the creation of such hazards.

While BESS are not inherently dangerous, their presence within the LF District introduces potential risks. In the event of an aircraft collision, BESS could trigger cascading impacts such as fire, explosion, or widespread power outages. Additionally, the infrastructure required to support BESS, particularly high-voltage transmission lines often exceed 65 feet in height surpassing the maximum height limit for the LF District.

For these reasons and regulatory constraints, staff recommends Commercial BESS be prohibited within the LF District.

OS – Open Space Zone

The OS zone is intended to permit land uses that tend to be managed in a largely undeveloped character, including passive parks, watersheds, natural and urban conservancy shoreline districts, significant wildlife habitats, and areas with significant development restrictions.

Permitting BESS in the OS Zone would require a demonstrated trend toward development, which is inconsistent with the zone's preservation-focused intent. While limited utility infrastructure, such as substations, or transmission lines is allowed, these facilities are typically modest in scale and impact compared to the potential footprint of a commercial scale BESS installation.

Given the City's commitment to preserving these areas to the fullest extent possible, staff recommends Commercial BESS be prohibited within the OS Zone.

P-1 Public Use Zone

The P-1 Zone, similar in purpose to the Institutional Zone, is intended to support public-services at a community and regional scale. It provides space for cultural, educational, recreational, and civic facilities such as schools parks, and government offices. The P-1 Zone is often located within or near residential zones.

While BESS are generally developed to serve the public good, their function does not completely align with the core intent of the P-1 Zone, which emphasizes active, community oriented uses. BESS would be best suited for facilities that rely on on-site power generation mirroring the patterns in the Institutional and DUC zones. BESS could remove the reliance on diesel generation and improve the overall reliability of the services provided.

For these reasons, staff recommends Commercial BESS may be allowed in the P-1 Zone through the Type III decision process.

Residential Zones

Residential Zones are intended to support a range of housing types, from single family homes to multistory apartment buildings while maintaining a focus on residential character and livability. Commercial and industrial activities are either significantly restricted or outright prohibited in these areas to preserve neighborhood integrity and minimize incompatible land uses.

Given these limitations, and the intent of residential zoning, staff recommends, that Commercial BESS be prohibited in all residential zones.

II. SUMMARY OF KEY CODE CHANGES

Staff is preparing revisions to Title 18 "Zoning," and more specifically the following Chapters:

- Chapter 18.04 ACC "Definitions"
- Chapter 18.07 ACC "Residential Zones"
- Chapter 18.23 ACC "Commercial and Industrial Zones"
- Chapter 18.29 ACC "DUC Downtown Urban Center District"
- Chapter 18.31 ACC "Supplemental Development Standards"
- Chapter 18.35 ACC "Special Purpose Zones"

Residential Zones

- Changes to this chapter include a revision to the use table ACC 18.07.020 to show commercial applications of BESS as prohibited with "X."
- There may be additional development standards for accessory uses referenced in the supplemental development standards captured in Chapter 18.31 ACC.

Commercial and Industrial Zones

- Changes to this chapter include the use table ACC 18.23.030 to show "X" in the C-1 zone, "A" in the C-2 Zone, and "P" in both the M-1 and M-2 zones.
- There may be additional development standards contained in Chapter 18.31 ACC.

DUC Downtown Urban Center District

- Changes to this chapter include the inclusion of BESS to the uses/activities requiring a conditional use permit.
- There may be additional development standards contained in Chapter 18.31 ACC.

Special Purpose Zones

- Changes to this chapter include the use table ACC 18.35.030 to show "C" in the P-1 zone, "C" in the I zone, and "X" in the OS zone.
- There may be additional development standards contained in Chapter 18.31 ACC.

Supplemental Development Standards

- The inclusion of additional siting and screening requirements. Such as accessory uses of BESS being required to be sited behind the front façade of the structure.
- Minor changes to required landscaping to prevent taller shrubbery from overtopping the wall.

Other Standards

The Washington State Amendments to the 2021 International Building Code (IBC) and International Fire Code—codified in WAC 51-54A-1207 (see Attachment 11)—establish development standards for both stationary and mobile BESS. Auburn will adopt these provisions by reference into the City Code, thereby streamlining local implementation and avoiding the need to develop duplicative or potentially conflicting regulations. This approach supports consistency with the State's clean energy trajectory and reinforces Auburn's commitment to resilient, forward-compatible infrastructure.

III. TEXT AMENDMENT

Draft text amendments have not been prepared for this meeting. Planning Services expects a draft version of code to be presented to Planning Commission at the January 6th meeting.

As a reference, PSE provided staff with a model ordinance intended as a guidance document for jurisdictions seeking to amend local codes to accommodate BESS as a permitted use. This model ordinance, included as Attachment 10, offers a useful framework for understanding the legal and operational considerations associated with BESS deployment.

However, while informative, the model ordinance does not fully address the specific considerations required to amend Title 18 as identified in this memo. Auburn's unique land use context, zoning structure, and policy objectives necessitate tailored updates to ensure consistency with the spirit and intent of Auburn City Code.

IV. ATTACHMENTS

(1) Staff Presentation
(2) King County Ordinance No. 19824
(3) SB 5116 – Clean Energy Transformation Act
(4) SB 5126 – Climate Commitment Act
(5) 2021 PSE Integrated Resource Plan
(6) City of Auburn Ordinance No. 6978 Establishment of 6-month Moratorium
(7) Round Table Meeting Notes
(8) City of Auburn Ordinance No. 6995 6-month Moratorium Extension
(9) Outreach and Survey Materials
(10) PSE Model Ordinance
(11) WAC 51-54A1207 Electrical Energy Storage Systems
(12) Outline and Functions of the US Energy Grid
(13) PSC Energy Storage System Location Study

VI. GLOSSARY OF KEY TERMS

(1) Accessory Energy Storage System (Accessory ESS / Accessory BESS)
A battery energy storage system with a capacity below the City's proposed 1-megawatt (MW) threshold. These systems are subordinate to a primary use—such as a residence or small facility—and provide backup power or limited grid support.

(2) Administrative Use Permit (Type II Decision)
An administrative land-use decision made by staff to determine whether a proposed use—such as a Commercial BESS in the C-2 Zone—meets zoning and development standards.

(3) Battery Energy Storage System (BESS)
A system of rechargeable batteries that stores electricity for later use. BESS improves grid stability, captures excess renewable energy, and provides backup power for homes, businesses, and essential facilities.

(4) Clean Energy Transformation Act (CETA)
Washington State legislation (SB 5116, 2019) that requires electric utilities to transition to 100% clean electricity by 2045, increasing demand for renewable energy and storage technologies.

(5) Climate Commitment Act (CCA)
Washington State legislation (SB 5126, 2021) establishing a cap-and-invest program that limits carbon emissions and funds climate and air-quality initiatives.

(6) Commercial Energy Storage System (Commercial ESS / BESS)
A battery energy storage system that exceeds the City's proposed 1-megawatt (MW) threshold. These systems may serve utility-scale or standalone commercial functions and require higher-level land-use review.

(7) Conditional Use Permit (Type III Decision)
A quasi-judicial land-use process requiring a public hearing and decision by the

Hearing Examiner. This review level is recommended for siting Commercial BESS in zones where community input and compatibility review are necessary.

(8) Distributed Energy Resources (DERs)
Small-scale energy technologies located near where energy is consumed, such as rooftop solar or BESS. DERs improve grid flexibility and local resilience.

(9) Downtown Urban Center (DUC)
A mixed-use zone intended for commercial, residential, civic, and medical uses. Commercial BESS may be permitted through Type III review when serving institutional or public-service needs.

(10) Energy Storage System (ESS)
A general term for installations that store energy for later use, including batteries, control systems, and power-conversion equipment. ESS systems help balance supply and demand on the electrical grid.

(11) Industrial Zones (M-1 Light Industrial and M-2 Heavy Industrial)
Zones intended for industrial, manufacturing, and commercial uses. These areas contain compatible infrastructure and are proposed to allow Commercial BESS outright.

(12) International Fire Code (IFC) Section 1207 / NFPA 855
State-adopted safety standards governing the design, installation, operation, and fire-protection requirements for energy storage systems. These standards will be referenced in Auburn's zoning updates.

(13) Integrated Resource Plan (IRP)
Puget Sound Energy's long-term energy planning document, identifying future energy needs, renewable resource integration, and the role of BESS in meeting regional capacity and reliability goals.

(14) Megawatt (MW)
A unit of electrical power equal to one million watts. Used to differentiate between accessory-scale (<1 MW) and commercial-scale (>1 MW) battery storage facilities.

(15) Moratorium
A temporary halt on accepting or processing specific development applications. Auburn established two consecutive six-month moratoriums on BESS projects to allow time for research and zoning updates.

(16) Open Space (OS) Zone
A zone intended to preserve passive parks, watersheds, habitat areas, and environmentally sensitive lands. Commercial BESS is proposed to be prohibited in this zone.

(17) Public Use (P-1) Zone
A zone intended for civic, recreational, and community-serving public facilities. Commercial BESS may be allowed through Type III review when supporting essential public uses.

(18) Quasi-Judicial Review
A formal land-use decision-making process involving public hearings and fact-finding,

typically associated with conditional use permitting for projects such as Commercial BESS in sensitive zones.

(19) Residential Zones

Zones intended primarily for housing. Commercial BESS is proposed to be prohibited in all residential zones, while Accessory uses of BESS remains allowed.

(20) Supplemental Development Standards (ACC 18.31)

Citywide development requirements that apply across multiple zones, including screening, siting, landscaping, and safety standards applicable to BESS installations.

(21) Transmission, Distribution, Generation, and Consumption

The four functional components of the electrical grid:

- *Generation*: where electricity is produced.
- *Transmission*: long-distance, high-voltage transport.
- *Distribution*: local delivery at safe voltages.
- *Consumption*: end-use by households, businesses, and institutions.

BESS supports all stages by storing and releasing energy as needed.

PLANNING COMMISSION

ENERGY STORAGE SYSTEM CODE UPDATE

PRESENTED BY
GABRIEL CULLINS, PLANNER II
DECEMBER 2, 2025

Department of Community Development

Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE

ENVIRONMENT

ECONOMY

CHARACTER

SUSTAINABILITY

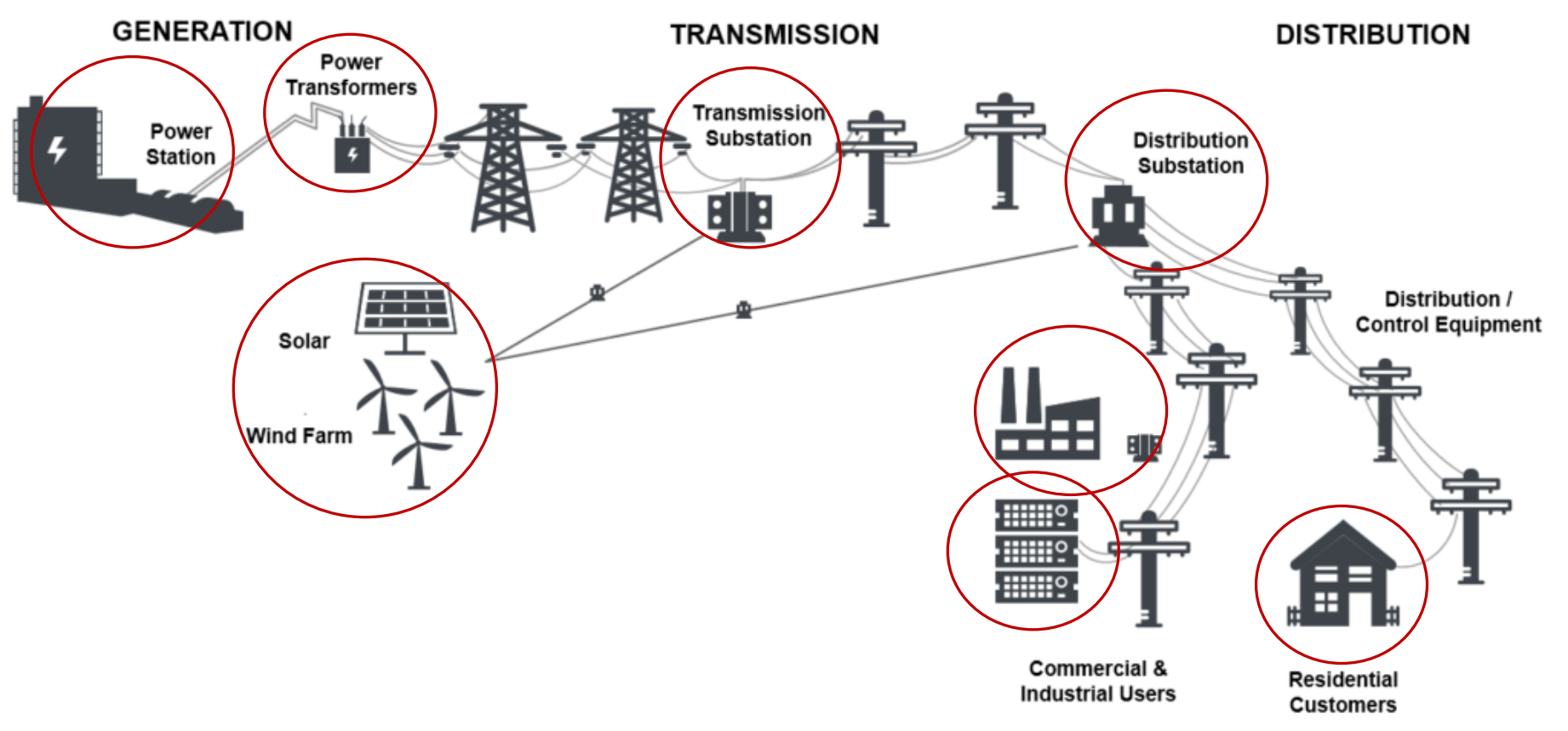
WELLNESS

CELEBRATION

OBJECTIVES

- Identify the *purpose* of the updates
- Identify regional *approaches* and *standards*
- Determine appropriate land use *approvals*

BACKGROUND


GENERATION
TRANSMISSION
DISTRIBUTION
Power Station
Power Transformers
Transmission Substation
Distribution Substation
Distribution / Control Equipment
Solar
Wind Farm
Commercial & Industrial Users
Residential Customers

BATTERY ENERGY STORAGE SYSTEMS

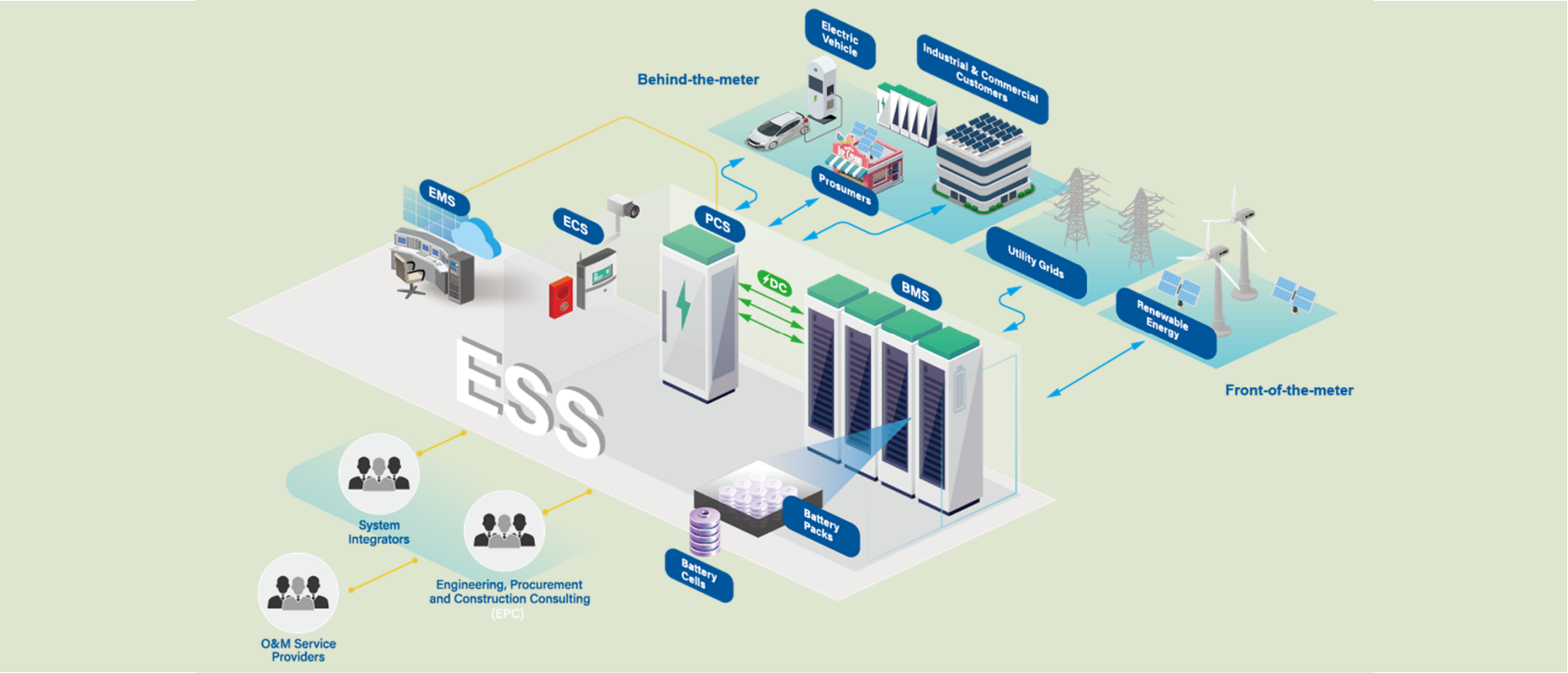


BATTERY ENERGY STORAGE SYSTEMS

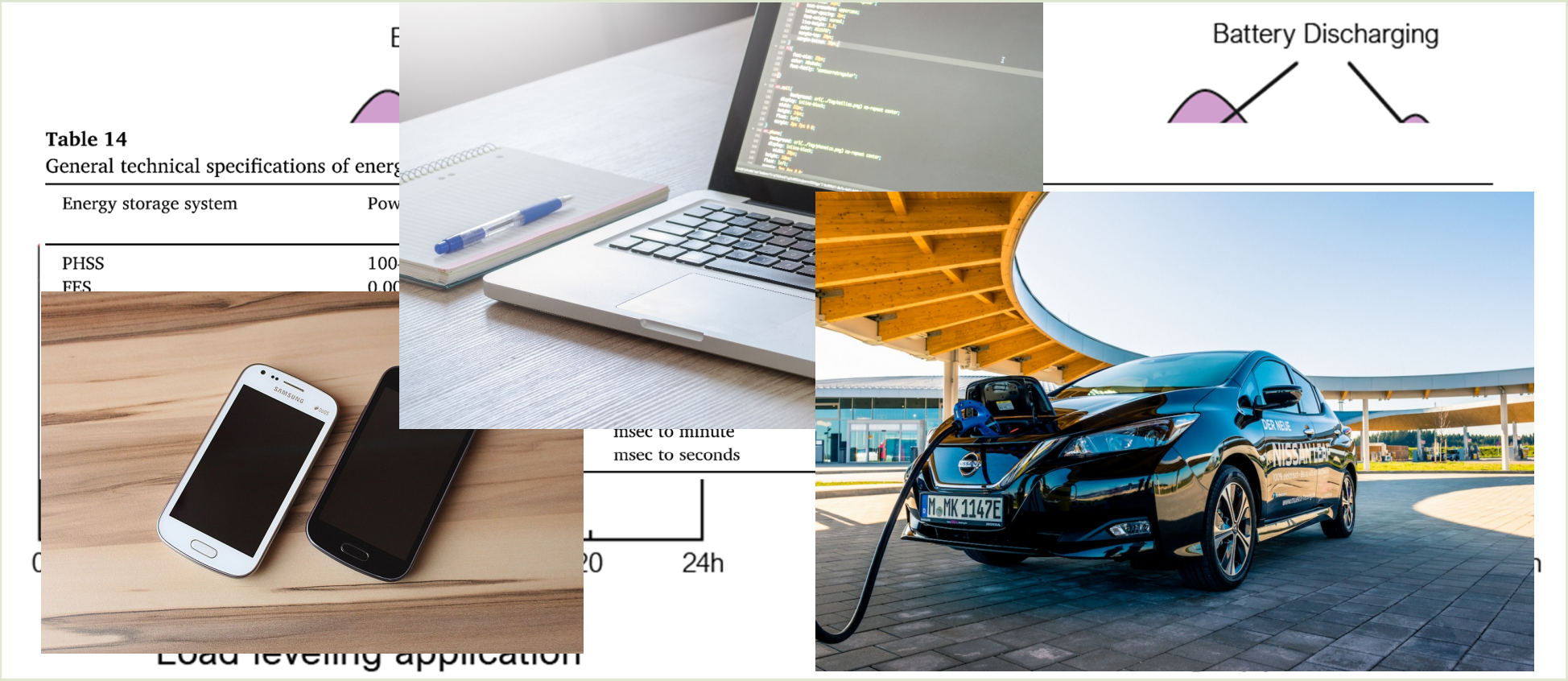




BATTERY ENERGY STORAGE SYSTEMS



BATTERY ENERGY STORAGE SYSTEMS



LEGISLATIVE ACTIONS AND INDUSTRY RESPONSES



RESEARCH RESULTS

- Zoning classification and thresholds vary
- Definitions vary – “BESS” / “Substation”

DEVELOPING STANDARDS

- Define thresholds
- Identify applicable zones – Commercial / Industrial
- Identify project permit decision types – I, II, or III
- Establish development standards

PROPOSED TIMELINE

JAN
- Present code to Planning Commission

FEB
- Planned Planning Commission Meeting

MAR
- Planned Public Hearing

APR
- Planned Council Study Session and Action

QUESTIONS?

Department of Community Development

Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE

ENVIRONMENT

ECONOMY

CHARACTER

SUSTAINABILITY

WELLNESS

CELEBRATION

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ATTACHMENT 2

KING COUNTY

1200 King County Courthouse
516 Third Avenue
Seattle, WA 98104

Signature Report

Ordinance 19824

Proposed No. 2023-0263.3 **Sponsors** Perry

AN ORDINANCE relating to energy storage systems; amending Ordinance 10870, Section 43, as amended, and K.C.C. 21A.06.015, Ordinance 10870, Section 44, as amended, and K.C.C. 21A.06.020, Ordinance 10870, Section 45, as amended, and K.C.C. 21A.06.025, Ordinance 10870, Section 330, as amended, and K.C.C. 21A.08.030, Ordinance 10870, Section 333, as amended, and K.C.C. 21A.08.060, Ordinance 10870, Section 335, as amended, and K.C.C. 21A.08.080, Ordinance 10870, Section 336, as amended, and K.C.C. 21A.08.090, Ordinance 10870, Section 337, as amended, and K.C.C. 21A.08.100, Ordinance 10870, Section 354, as amended, and K.C.C. 21A.12.170, Ordinance 10870, Section 359, as amended, and K.C.C. 21A.12.220, Ordinance 10870, Section 388, as amended, and K.C.C. 21A.16.030, Ordinance 10870, Section 390, as amended, and K.C.C. 21A.16.050, Ordinance 10870, Section 391, as amended, and K.C.C. 21A.16.060, and Ordinance 12020, Section 17, as amended, and K.C.C. 27A.30.060, adding a new section

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to K.C.C. chapter 21A.06, and adding a new chapter to K.C.C. Title 21A.

BE IT ORDAINED BY THE COUNCIL OF KING COUNTY:

SECTION 1. **Findings:**

A. Battery energy storage systems play a crucial role in modern energy supply by providing efficient and flexible storage for electricity generated from renewable energy sources, such as solar and wind power. They help address the intermittent nature of these sources by storing excess electricity during times of low demand and releasing it when demand is high. That enhances grid stability and reliability when implemented on a region-wide scale, and increases the reliability of electricity supply for individual uses when installed to back up consumer-scale renewable energy generation systems.

B. The use of battery energy storage systems has been rapidly increasing worldwide due to advancements in battery technology, decreasing costs, heightened electricity demand, and the growing adoption of renewable energy generation. The deployment of battery energy storage systems has undergone substantial growth in recent years, driven by both utility-scale installations and distributed systems at residential, commercial, and industrial levels.

C. King County strives to be a leader in battery energy storage system deployment. By making renewable energy sources more reliable, battery energy storage systems are important in helping King County meet its Strategic Climate Action Plan goal of reducing greenhouse gas emissions in the county by eighty percent by 2050. To this end, the 2020 Strategic Climate Action Plan sets a target of building one hundred

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megawatts of battery energy storage per utility serving King County by 2030, and 200 megawatts of battery energy storage per utility serving King County by 2045. Battery energy storage can play an important role in meeting the requirements of the state's Clean Energy Transformation Act – net neutral greenhouse gas emissions by 2030 and one hundred percent clean electricity by 2045 – reliably and cost effectively. Batteries help bridge the gap in peak demand hours when the sun is not shining and the wind is not blowing by supporting a more flexible and resilient electricity system. King County has already demonstrated its commitment to deploying battery energy storage systems by installing a 10-megawatt system at its West Point wastewater treatment plant. The system will make the county's wastewater treatment system resilient to voltage sags that have caused major disruptions to the plant's operation in the past, and demonstrate the technology's viability, safety, and importance to a clean, efficient, and resilient energy system.

D. To meet the county's battery storage deployment target and the county's overall climate goals, it is important that battery energy storage systems be deployed at all scales, from accessory residential uses of a few kilowatts up to utility-scale systems of 100 or more megawatts. Those larger systems consisting of hundreds of megawatts require large sites that are typically only found in the rural area and natural resource lands. This ordinance advances these Strategic Climate Action Plan priorities by making battery energy storage systems of all scales an allowed use on nearly ninety-seven percent of the county's unincorporated land area.

E. The remaining three percent of the county's unincorporated land area is made up of agricultural lands. Being the most urban county in the state, King County has very

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little agricultural land, nearly all of which is protected as agricultural land of long-term significance for the commercial production of food or other agricultural products under the Growth Management Act and RCW 36.70A.170. That land contains rich agricultural soils, which are a precious and finite resource.

F. In order to maintain consistency with the Growth Management Act and protect agricultural lands for present and future generations, this ordinance only allows battery energy storage systems in agricultural zones as an accessory use, up to 2 megawatts. The 2-megawatt allowance leaves flexibility for farmers to store energy for their own use and to participate in energy sharing with their neighbors through microgrid applications, while maintaining a small footprint, which is likely less than four-hundred square feet. If there is no feasible alternative to constructing battery energy storage systems on agricultural lands, King County can consider granting special use permit authority for these systems in the next code update to address reliability issues at any substation proximate to agricultural lands.

G. Because widespread use of battery energy storage systems is a relatively recent phenomenon, there are not currently regulations in King County's zoning code that specifically address them. The requirements of this ordinance and existing land use and environmental regulations in the King County Code ensure that battery energy storage systems are built and located to minimize disruption of natural resource-related activity, are compatible with resource management, and protect public health and safety and the environment.

H. While battery energy storage systems offer the advantages cited in subsections A. through E. of this section, there are also potential risks associated

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with the technology. Thermal incidents have been reported at battery energy storage facilities in the United States and abroad.

I. The Washington Administrative Code created new requirements, effective March 2024, intended to minimize the risk of damage to nearby structures and properties. These requirements include a hazard mitigation analysis that must demonstrate that thermal events will be contained for the minimum duration of the required fire-resistance-rated separations, and will allow occupants or the general public to evacuate to a safe location. They also include large-scale fire testing conducted or witnessed and reported by an approved testing laboratory, as well as numerous requirements that minimize the risk of thermal runaway and associated secondary risks such as inhalation of smoke and gases. The updated Washington Administrative Code standards also include requirements regarding the size and location of battery energy storage systems contained in residences.

J. It is important that the owners of battery energy storage systems using certain technologies and configurations in close proximity to other structures and properties carry financial responsibility for public liability and environmental impacts to other persons or properties in the low likelihood of a safety event.

K. It is also important that battery energy storage system operators have clear emergency response plans if a thermal event occurs. State law requires fire safety and evacuation plans be in place before commissioning of a battery energy storage system facility. Those plans and their execution protect the community, the environment, and first responders if there is a thermal event at a facility. This

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ordinance further requires confirmation that the plans have been shared with the local fire jurisdiction to ensure that there is close coordination between the operator and first responders.

L. Additionally, it is important that battery energy storage system operators have both a plan and financial capacity for decommissioning the system and removing it from the site. State law requires that the decommissioning plan take into account both decommissioning after the normal course of the system's life, as well as decommissioning after a thermal event. Although state law requires a decommissioning plan, it does not guarantee that the operator will have the financial capacity to complete decommissioning and site cleanup. This ordinance therefore requires applicants to carry and maintain financial responsibility sufficient to complete the decommissioning of the battery energy storage system, including removal of all equipment from the site, and completion of any necessary cleanup. After removal from the site, the Washington Administrative Code prescribes the waste disposal processes that must be followed when disposing of the batteries.

M. In their "Battery Energy Storage Systems" article in the March 2024 edition of the American Planning Association's Zoning Practice magazine, Brian Ross, AICP, and Monika Vadali, PhD, analyzed several zoning ordinances addressing battery energy storage systems, and identified best practices. Pacific Northwest National Laboratory also published a paper in October 2023, titled "Energy Storage in Local Zoning Ordinances," which identified potential impacts from battery energy storage systems and their implications for zoning standards.

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Taken together, this ordinance, existing county regulations, and state law address all the best practices and potential impacts identified in those articles.

SECTION 2. Ordinance 10870, Section 43, as amended, and K.C.C. 21A.06.015 are each hereby amended as follows:

Accessory use, commercial/industrial: an accessory use to a commercial or industrial use, including, but not limited to:

A. Administrative offices;

B. Employee exercise facilities;

C. Employee food service facilities;

D. Incidental storage of raw materials and finished products sold or manufactured on-site;

E. Business owner or caretaker residence;

F. Cogeneration facilities;

G. Ground maintenance facilities; ((~~and~~))

H. Consumer-scale renewable energy systems; and

I. Battery energy storage systems meeting the requirements of K.C.C. 21A.08.060.B.41.

SECTION 3. Ordinance 10870, Section 44, as amended, and K.C.C. 21A.06.020 are each hereby amended as follows:

Accessory use, residential: an accessory use to a residential use, including, but not limited to:

A. Accessory living quarters and dwellings;

B. Fallout or bomb shelters;

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C. Keeping household pets or operating a hobby cattery or hobby kennel;

D. On-site rental office;

E. Pools, private docks, or piers;

F. Antennae for private telecommunication services;

G. Storage of yard maintenance equipment;

H. Storage of private vehicles, such as motor vehicles, boats, trailers, or planes;

I. Greenhouses;

J. Recreation space areas required under K.C.C. 21A.14.180 and play areas required under K.C.C. 21A.14.190;

K. Home occupations and home industries under K.C.C. chapter 21A.30; ((~~and~~))

L. Consumer-scale renewable energy systems; and

M. Battery energy storage systems meeting the requirements of K.C.C. 21A.08.030.B.7.

SECTION 4. Ordinance 10870, Section 45, as amended, and K.C.C. 21A.06.025 are each hereby amended as follows:

Accessory use, resource: an accessory use to a resource use, including, but not limited to:

A. Housing of agricultural workers;

B. Storage of agricultural products or equipment used on site; ((~~and~~))

C. Consumer-scale renewable energy systems; and

D. Battery energy storage systems meeting the requirements of K.C.C. 21A.08.090.B.

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NEW SECTION. SECTION 5. There is hereby added to K.C.C. chapter 21A.06 a new section to read as follows:

Battery energy storage system: A system consisting of one or more rechargeable batteries assembled together, capable of storing energy in order to supply electrical energy at a future time. Such systems typically include battery chargers, controls, power conditioning systems, and associated electrical equipment, and are typically used to provide standby or emergency power, uninterruptable power supply, load shedding, load sharing, smoothing and dispatching of intermittent renewable energy sources, or similar capabilities.

SECTION 6. Ordinance 10870, Section 330, as amended, and K.C.C. 21A.08.030 are each hereby amended as follows:

A. Residential land uses.

P-Permitted Use **C-Conditional Use** **S-Special Use**		**RESOURCE**			**R U R A L**	**RESIDENTIAL**			**COMMERCIAL/INDUSTRIAL**				
SIC #	**SPECIFIC LAND USE**	**A**	**F**	**M**	**RA**	**UR**	**R1-8**	**R12 -48**	**NB**	**CB**	**RB**	**O**	**I**
	DWELLING UNITS, TYPES:												
*	Single Detached	P C12	P2		P C12	P C12	P C12	P C12	P15				
*	Townhouse				C4	C4	P11 C12	P	P3	P3	P3	P3	
*	Apartment				C4	C4	P5	P	P3	P3	P3	P3	

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							C5						
*	Mobile Home Park				S13		C8	P					
*	Cottage Housing						P15						
	GROUP RESIDENCES:												
*	Community Residential Facility-I				C	C	P14. a C	P	P3	P3	P3	P3	
*	Community Residential Facility-II						P14. b	P	P3	P3	P3	P3	
*	Dormitory				C6	C6	C6	P					
*	Senior Citizen Assisted Housing					P4	P4	P	P3	P3	P3	P3	
	ACCESSORY USES:												
*	Residential Accessory Uses	P7	P7		P7	P7	P7	P7	P7	P7	P7	P7	
*	Home Occupation	P18	P18		P18	P18	P18	P18	P18	P18	P18	P18	
*	Home Industry	C			C	C	C						
	TEMPORARY LODGING:												
7011	Hotel/Motel (1)									P	P	P	
*	Bed and Breakfast Guesthouse	P9			P9	P9	P9	P9	P9	P10	P10		
7041	Organization Hotel/Lodging Houses						P17				P		

B. Development conditions.

1. Except bed and breakfast guesthouses.

2. In the forest production district, the following conditions apply:

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a. Site disturbance associated with development of any new residence shall be limited to three acres. Site disturbance shall mean all land alterations including, but not limited to, grading, utility installation, landscaping, clearing for crops, on-site sewage disposal systems, and driveways. Additional site disturbance for agriculture, including raising livestock, up to the smaller of thirty-five percent of the lot or seven aces, may be approved only if a farm management plan is prepared in accordance with K.C.C. chapter 21A.30. Animal densities shall be based on the area devoted to animal care and not the total area of the lot;

b. A forest management plan shall be required for any new residence in the forest production district, that shall be reviewed and approved by the King County department of natural resources and parks before building permit issuance; and

c. The forest management plan shall incorporate a fire protection element that includes fire safety best management practices developed by the department.

3. Only as part of a mixed use development subject to the conditions of K.C.C. chapter 21A.14, except that in the NB zone on properties with a land use designation of commercial outside of center (CO) in the urban areas, stand-alone townhouse developments are permitted subject to K.C.C. 21A.12.040, 21A.14.030, 21A.14.060 and 21A.14.180.

4. Only in a building listed on the National Register as an historic site or designated as a King County landmark subject to K.C.C. chapter 21A.32.

5.a. In the R-1 zone, apartment units are permitted, if:

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(1) At least fifty percent of the site is constrained by unbuildable critical areas. For purposes of this subsection, unbuildable critical areas includes wetlands, aquatic areas, and slopes forty percent or steeper and associated buffers; and

(2) The density does not exceed a density of eighteen units per acre of net buildable area.

b. In the R-4 through R-8 zones, apartment units are permitted if the density does not exceed a density of eighteen units per acre of net buildable area.

c. If the proposal will exceed base density for the zone in which it is proposed, a conditional use permit is required.

6. Only as accessory to a school, college, university, or church.

7.a. Accessory dwelling units are subject to the following standards:

(1) Only one accessory dwelling per primary single detached dwelling or townhouse unit;

(2) Only allowed in the same building as the primary dwelling unit, except that detached accessory dwelling units are allowed when there is no more than one primary dwelling unit on the lot, and the following conditions are met:

(a) the lot must be three thousand two hundred square feet or greater if located in the urban area or a rural town; or

(b) the lot must meet the minimum lot area for the applicable zone if located in the rural area but not in a rural town, except that if one transferable development right is purchased from the Rural Area or Natural Resource Lands under K.C.C. chapter 21A.37, a detached accessory dwelling unit is allowed on a RA-5 zoned lot that is two and one-half acres or greater;

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(3) The accessory dwelling unit shall not exceed one thousand square feet of heated floor area and one thousand square feet of unheated floor area except:

(a) when the accessory dwelling unit is wholly contained within a basement or attic, this limitation does not apply;

(b) for detached accessory dwelling units, the floor area contained in a basement does not count toward the floor area maximum; or

(c) on a site zoned RA if one transferable development right is purchased from the Rural Area or Natural Resource Lands under K.C.C. chapter 21A.37, the accessory dwelling unit is permitted a maximum heated floor area of one thousand five hundred square feet and one thousand five-hundred square feet of unheated floor area;

(4) Accessory dwelling units that are not wholly contained within an existing dwelling unit shall not exceed the base height established in 21A.12.030;

(5) When the primary and accessory dwelling units are located in the same building, or in multiple buildings connected by a breezeway or other structure, only one entrance may front a street;

(6) No additional off-street parking spaces are required for accessory dwelling units;

(7) The primary dwelling unit or the accessory dwelling unit shall be occupied either by the owner of the primary dwelling unit or by an immediate family member of the owner. Immediate family members are limited to spouses, siblings, parents, grandparents, children, and grandchildren, either by blood, adoption, or marriage, of the owner. The accessory dwelling unit shall be converted to another

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permitted use or shall be removed if neither dwelling unit is occupied by the owner or an immediate family member;

(8) An applicant seeking to build an accessory dwelling unit shall file a notice approved by the department of executive services, records and licensing services division, that identifies the dwelling unit as accessory. The notice shall run with the land. The applicant shall submit proof that the notice was filed before the department approves any permit for the construction of the accessory dwelling unit. The required contents and form of the notice shall be set forth in administrative rules;

(9) Accessory dwelling units are not allowed in the F zone;

(10) Accessory dwelling units should be designed to be compatible with the primary dwelling unit and the surrounding properties, including material, colors, and building forms; and

(11) The applicant should consider a siting alternatives study that analyzes placement options of the accessory dwelling unit on the property to minimize impacts to privacy and views for surrounding property owners.

b. Accessory living quarters:

(1) are limited to one per lot;

(2) are allowed only on lots of three thousand two hundred square feet or greater when located in the urban area or a rural town;

(3) shall not exceed the base height as established in K.C.C. 21A.12.030;

(4) shall not exceed one thousand square feet of heated floor area and one thousand square feet of unheated floor area; and

(5) are not allowed in the F zone.

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c. One single or twin engine, noncommercial aircraft shall be permitted only on lots that abut, or have a legal access that is not a county right-of-way, to a waterbody or landing field, but only if there are:

(1) no aircraft sales, service, repair, charter, or rental; and

(2) no storage of aviation fuel except that contained in the tank or tanks of the aircraft.

d. Battery energy storage systems are considered a residential accessory use when the total system capacity is two megawatts or less, and:

(1) the system provides electricity for on-site use only, with "on-site use" including net metering as well as charging of vehicles on-site or in the right-of-way immediately adjacent to the site; or

(2) the system is intended primarily for on-site use, but also participates in load sharing or another grid-connected electricity-sharing arrangement.

e. Buildings for residential accessory uses in the RA and A zone shall not exceed five thousand square feet of gross floor area, except for buildings related to agriculture or forestry.

8. Mobile home parks shall not be permitted in the R-1 zones.

9. Only as accessory to the permanent residence of the operator, and:

a. Serving meals shall be limited to paying guests; and

b. The number of persons accommodated per night shall not exceed five, except that a structure that satisfies the standards of the International Building Code as adopted by King County for R-1 occupancies may accommodate up to ten persons per night.

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10. Only if part of a mixed use development, and subject to the conditions of subsection B.9. of this section.

11. Townhouses are permitted, but shall be subject to a conditional use permit if exceeding base density.

12. Required before approving more than one dwelling on individual lots, except on lots in subdivisions, short subdivisions, or binding site plans approved for multiple unit lots, and except as provided for accessory dwelling units in subsection B.7. of this section.

13. No new mobile home parks are allowed in a rural zone.

14.a. Limited to domestic violence shelter facilities.

b. Limited to domestic violence shelter facilities with no more than eighteen residents or staff.

15. Only in the R4-R8 zones subject to the following standards:

a. Developments shall contain only cottage housing units with no fewer than three units. If the site contains an existing home that is not being demolished, the existing house is not required to comply with the height limitation in K.C.C. 21A.12.020.B.25. or the floor area and footprint limits in K.C.C. 21A.14.025.B.;

b. Cottage housing developments should consider including a variety of housing sizes, such as units with a range of bedroom sizes or total floor area; and

c. Before filing an application with the department, the applicant shall hold a community meeting in accordance with K.C.C. 20.20.035.

16. The development for a detached single-family residence shall be consistent with the following:

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a. The lot must have legally existed before March 1, 2005;

b. The lot has a Comprehensive Plan land use designation of Rural Neighborhood Commercial Center or Rural Area; and

c. The standards of this title for the RA-5 zone shall apply.

17. Only in the R-1 zone as an accessory to a golf facility and consistent with K.C.C. 21A.08.040.

18. Allowed if consistent with K.C.C. chapter 21A.30.

SECTION 7. Ordinance 10870, Section 333, as amended, and K.C.C. 21A.08.060 are each hereby amended as follows:

A. Government/business services land uses.

P-Permitted Use **C-Conditional Use** **S-Special Use**		**RESOURCE**			**RURAL**	**RESIDENTIAL**			**COMMERCIAL/INDUSTRIAL**				
SIC#	**SPECIFIC LAND USE**	**A**	**F**	**M**	**RA**	**UR**	**R1-8**	**R12-48**	**NB**	**CB**	**RB**	**O**	**I (30)**
	GOVERNMENT SERVICES:												
*	Public agency or utility office				P3 C5	P3 C5	P3 C	P3 C	P	P	P	P	P16
*	Public agency or utility yard				P27	P27	P27	P27			P		P
*	Public agency archives										P	P	P
921	Court									P4	P	P	
9221	Police Facility				P7	P7	P7	P7	P7	P	P	P	P
9224	Fire Facility				C6 and	C6	C6	C6	P	P	P	P	P

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					33								
*	Utility Facility	P29 C28	P29 C28	P29 C28	P29 C28 and 33	P29 C28	P29 C28	P29 C28	P	P	P	P	P
*	Commuter Parking Lot				C 33 P19	C P19	C P19	C 19	P	P	P	P	P35
*	Private Stormwater Management Facility	P8	P8	P8	P8	P8	P8	P8	P8	P8	P8	P8	P8
*	Vactor Waste Receiving Facility	P	P	P	P18	P18	P18	P18	P31	P31	P31	P31	P
	BUSINESS SERVICES:												
*	Construction and Trade				P34						P	P9	P
*	Individual Transportation and Taxi									P25	P	P10	P
421	Trucking and Courier Service									P11	P12	P13	P
*	Warehousing, (1) and Wholesale Trade												P
*	Self-service Storage							P14	P37	P	P	P	P
4221 4222	Farm Product Warehousing, Refrigeration and Storage (38)												P
*	Log Storage (38)		P		P26 and 33								P

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47	Transportation Service												P39
473	Freight and Cargo Service										P	P	P
472	Passenger Transportation Service									P	P	P	
48	Communication Offices										P	P	P
482	Telegraph and other Communications									P	P	P	P
*	General Business Service								P	P	P	P	P16
*	Professional Office								P	P	P	P	P16
7312	Outdoor Advertising Service										P	P17	P
735	Miscellaneous Equipment Rental									P17	P	P17	P
751	Automotive Rental and Leasing									P	P		P
752	Automotive Parking								P20a	P20b	P21	P20a	P
*	Off-Street Required Parking Lot				P32	P32	P32	P32	P32	P32	P32	P32	P32
7941	Professional Sport Teams/Promoters										P	P	
873	Research, Development and Testing										P2	P2	P2
*	Heavy Equipment and Truck Repair												P
	ACCESSORY USES:												
*	Commercial/Industrial Accessory Uses			P41	P22 P41				P22 P41	P22 P41	P41	P41	P41

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*	Helistop				40	C23	C2 33	C23	C23	C23	C24	C23	C24

B. Development conditions.

1. Except self-service storage.

2. Except SIC Industry No. 8732-Commercial Economic, Sociological, and Educational Research, see general business service/office.

3.a. Only as a reuse of a public school facility or a surplus nonresidential facility subject to K.C.C. chapter 21A.32; or

b. only when accessory to a fire facility and the office is no greater than one thousand five hundred square feet of floor area.

4. Only as a reuse of a surplus nonresidential facility subject to K.C.C. chapter 21A.32.

5. New utility office locations only if there is no commercial/industrial zoning in the utility district, and not in the RA-10 or RA-20 zones unless it is demonstrated that no feasible alternative location is possible, and provided further that this condition applies to the UR zone only if the property is located within a designated unincorporated Rural Town.

6.a. All buildings and structures shall maintain a minimum distance of twenty feet from property lines adjoining rural area and residential zones;

b. Any buildings from which fire-fighting equipment emerges onto a street shall maintain a distance of thirty-five feet from such street;

c. No outdoor storage; and

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d. Excluded from the RA-10 and RA-20 zones unless it is demonstrated that no feasible alternative location is possible.

7. Limited to storefront police offices. Such offices shall not have:

a. holding cells;

b. suspect interview rooms (except in the NB zone); or

c. long-term storage of stolen properties.

8. Private stormwater management facilities serving development proposals located on commercial/industrial zoned lands shall also be located on commercial/industrial lands, unless participating in an approved shared facility drainage plan. Such facilities serving development within an area designated urban in the King County Comprehensive Plan shall only be located in the urban area.

9. No outdoor storage of materials.

10. Limited to office uses.

11. Limited to self-service household moving truck or trailer rental accessory to a gasoline service station.

12. Limited to self-service household moving truck or trailer rental accessory to a gasoline service station and SIC Industry No. 4215-Courier Services, except by air.

13. Limited to SIC Industry No. 4215-Courier Services, except by air.

14. Accessory to an apartment development of at least twelve units provided:

a. The gross floor area in self service storage shall not exceed the total gross floor area of the apartment dwellings on the site;

b. All outdoor lights shall be deflected, shaded, and focused away from all adjoining property;

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c. The use of the facility shall be limited to dead storage of household goods;

d. No servicing or repair of motor vehicles, boats, trailers, lawn mowers, or similar equipment;

e. No outdoor storage or storage of flammable liquids, highly combustible or explosive materials, or hazardous chemicals;

f. No residential occupancy of the storage units;

g. No business activity other than the rental of storage units; and

h. A resident director shall be required on the site and shall be responsible for maintaining the operation of the facility in conformance with the conditions of approval.

i. Before filing an application with the department, the applicant shall hold a community meeting in accordance with K.C.C. 20.20.035.

15. Repealed.

16. Only as an accessory use to another permitted use.

17. No outdoor storage.

18. Only as an accessory use to a public agency or utility yard, or to a transfer station.

19. Limited to new commuter parking lots designed for thirty or fewer parking spaces or commuter parking lots located on existing parking lots for churches, schools, or other permitted nonresidential uses that have excess capacity available during commuting; provided that the new or existing lot is adjacent to a designated arterial that has been improved to a standard acceptable to the department of local services;

20.a. No tow-in lots for damaged, abandoned, or otherwise impounded vehicles, and

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b. Tow-in lots for damaged, abandoned, or otherwise impounded vehicles shall be:

(1) permitted only on parcels located within Vashon Town Center;

(2) accessory to a gas or automotive service use; and

(3) limited to no more than ten vehicles.

21. No dismantling or salvage of damaged, abandoned, or otherwise impounded vehicles.

22. Storage limited to accessory storage of commodities sold at retail on the premises or materials used in the fabrication of commodities sold on the premises.

23. Limited to emergency medical evacuation sites in conjunction with police, fire, or health service facility. Helistops are prohibited from the UR zone only if the property is located within a designated unincorporated Rural Town.

24. Allowed as accessory to an allowed use.

25. Limited to private road ambulance services with no outside storage of vehicles.

26. Limited to two acres or less.

27a. Utility yards only on sites with utility district offices; or

b. Public agency yards are limited to material storage for road maintenance facilities.

28. Limited to local distribution gas storage tanks that pipe to individual residences but excluding liquefied natural gas storage tanks.

29. Excluding local distribution gas storage tanks.

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30. For I-zoned sites located outside the urban growth area designated by the King County Comprehensive Plan, uses shall be subject to the provisions for rural industrial uses in K.C.C. chapter 21A.12.

31. Vactor waste treatment, storage, and disposal shall be limited to liquid materials. Materials shall be disposed of directly into a sewer system, or shall be stored in tanks (or other covered structures), as well as enclosed buildings.

32. Provided:

a. Off-street required parking for a land use located in the urban area must be located in the urban area;

b. Off-street required parking for a land use located in the rural area must be located in the rural area; and

c.(1) Except as provided in subsection B.32.c.(2) of this section, off-street required parking must be located on a lot that would permit, either outright or through a land use permit approval process, the land use the off-street parking will serve.

(2) For a social service agency allowed under K.C.C. 21A.08.050B.13.b. to be located on a site in the NB zone, off-street required parking may be located on a site within three hundred feet of the social service agency, regardless of zoning classification of the site on which the parking is located.

33. Subject to review and approval of conditions to comply with trail corridor provisions of K.C.C. chapter 21A.14 when located in an RA zone.

34. Limited to landscape and horticultural services (SIC 078) that are accessory to a retail nursery, garden center, and farm supply store. Construction equipment for the accessory use shall not be stored on the premises.

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35. Allowed as a primary or accessory use to an allowed industrial-zoned land use.

36. Repealed.

37. Use shall be limited to the NB zone on parcels outside of the Urban Growth Area, Rural Towns and Rural Neighborhoods and the building floor area devoted to such use shall not exceed ten thousand square feet.

38. If the farm product warehousing, refrigeration and storage, or log storage, is associated with agriculture activities it will be reviewed in accordance with K.C.C. 21A.08.090.

39. Excluding fossil fuel facilities.

40. Helistops are not allowed in the RA zone as an accessory to a government or business services use, but may be allowed in that zone as part of a search and rescue facility, subject to K.C.C. 21A.08.100.B.30.

41. Battery energy storage systems are considered a commercial/industrial accessory use when the total system capacity is two megawatts or less, and:

a. the system provides electricity for on-site use only, with "on-site use" including net metering as well as charging of vehicles on-site or in the right-of-way immediately adjacent to the site; or

b. the system is intended primarily for on-site use, but also participates in load sharing or another grid-connected electricity-sharing arrangement.

SECTION 8. Ordinance 10870, Section 335, as amended, and K.C.C. 21A.08.080 are hereby amended to read as follows:

A. Manufacturing land uses.

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P-Permitted Use **C-Conditional Use** **S-Special Use**		**RESOURCE**			**RURAL**	**RESIDENTIAL**			**COMMERCIAL/INDUSTRIAL**				
SIC #	**SPECIFIC LAND USE**	**A**	**F**	**M**	**RA**	**UR**	**R1-8**	**R12-48**	**NB**	**CB**	**RB**	**O**	**I (11)**
20	Food and Kindred Products (28)								P2	P2	P2 C		P2 C
*	Winery/Brewery /Distillery Facility I				P32								
*	Winery/Brewery /Distillery Facility II	P3			P3 C30				P17	P17	P29		P31
	Winery/Brewery /Distillery Facility III	C12			C12				C29	C29	C29		C31
*	Materials Processing Facility		P13 C	P14 C15	P16 C								P
22	Textile Mill Products												C
23	Apparel and other Textile Products										C		P
24	Wood Products, except furniture	P4 P18	P4 P18 C5		P4 P18 C5	P4					C6		P
25	Furniture and Fixtures		P19		P19						C		P
26	Paper and Allied Products												C
27	Printing and Publishing								P7	P7	P7C	P7C	P
*	Marijuana Processor I	P20			P27					P21 C22	P21 C22		
*	Marijuana Processor II									P23 C24	P23 C24		P25 C26
28	Chemicals and Allied Products												C
2911	Petroleum Refining and Related Industries												C

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30	Rubber and Misc. Plastics Products												C
31	Leather and Leather Goods										C		P
32	Stone, Clay, Glass and Concrete Products									P6	P9		P
33	Primary Metal Industries												C
34	Fabricated Metal Products												P
35	Industrial and Commercial Machinery												P
351-55	Heavy Machinery and Equipment												C
357	Computer and Office Equipment										C	C	P
36	Electronic and other Electric Equipment										C		P
374	Railroad Equipment												C
376	Guided Missile and Space Vehicle Parts												C
379	Miscellaneous Transportation Vehicles												C
38	Measuring and Controlling Instruments										C	C	P
39	Miscellaneous Light Manufacturing										C		P
*	Motor Vehicle and Bicycle Manufacturing												C
*	Aircraft, Ship and Boat Building												P10C
7534	Tire Retreading										C		P
781-82	Movie Production/Distribution										P		P

474 B. Development conditions.

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1. Repealed.

2. Except slaughterhouses.

3.a. In the A zone, only allowed on sites where the primary use is SIC Industry Group No. 01-Growing and Harvesting Crops or No. 02-Raising Livestock and Small Animals;

b. Only allowed on lots of at least two and one-half acres, except that this requirement shall not apply on Vashon-Maury Island to winery, brewery or distillery business locations in use and licensed to produce by the Washington state Liquor and Cannabis Board before January 1, 2019, and that in the RA zone, for sites that contain a building designated as historic resource under K.C.C. chapter 20.62, only allowed on lots of at least two acres;

c. The aggregated floor area of structures and areas for winery, brewery, distillery facility uses shall not exceed three thousand five hundred square feet, unless located in whole or in part in a structure designated as historic resource under K.C.C. chapter 20.62, in which case the aggregated floor area of structures and areas devoted to winery, brewery, distillery facility uses shall not exceed seven thousand square feet in the RA zone and five thousand square feet in the A zone. Decks that are not occupied and not open to the public are excluded from the calculation for maximum aggregated floor area;

d. Structures and parking areas for winery, brewery, distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62, except that on Vashon-Maury Island this

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setback requirement shall not apply to structures and parking areas in use on December 4, 2019, by existing winery, brewery or distillery business locations licensed to produce by the Washington state Liquor and Cannabis Board before January 1, 2019;

e. In the A zone, sixty percent or more of the products processed must be grown on-site. At the time of the initial application under K.C.C. chapter 6.74, the applicant shall submit a projection of the source of products to be produced;

f. At least two stages of production of wine, beer, cider or distilled spirits, such as crushing, fermenting, distilling, barrel or tank aging, or finishing, as authorized by the Washington state Liquor and Cannabis Board production license, shall occur on-site. At least one of the stages of production occurring on-site shall include crushing, fermenting or distilling;

g. In the A zone, structures and area for non-agricultural winery, brewery, distillery facility uses shall be located on portions of agricultural lands that are unsuitable for agricultural purposes, such as areas within the already developed portion of such agricultural lands that are not available for direct agricultural production, or areas without prime agricultural soils. No more than one acre of agricultural land may be converted to a nonagricultural accessory use;

h. Tasting and retail sales of products produced on-site may occur only as accessory to the primary winery, brewery, distillery production use and may be provided in accordance with state law. The area devoted to on-site tasting or retail sales shall be limited to no more than thirty percent of the aggregated floor area and shall be included in the aggregated floor area limitation in subsection B.3.c. of this section. The limitation on tasting and retail sales of products produced on-site shall not apply on Vashon-Maury

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Island to winery, brewery, or distillery business locations in use and licensed to produce by the Washington state Liquor and Cannabis Board before January 1, 2019, or on sites in the RA zone that contain a building designated as historic resource under K.C.C. chapter 20.62. Incidental retail sales of merchandise related to the products produced on-site is allowed subject to the restrictions described in this subsection B.3. Hours of operation for on-site tasting of products shall be limited as follows: Mondays, Tuesdays, Wednesdays and Thursdays, tasting room hours shall be limited to 11:00 a.m. through 7:00 p.m.; and Fridays, Saturdays and Sundays, tasting room hours shall be limited to 11:00 a.m. through 9:00 p.m.;

i. Access to the site shall be directly to and from an arterial roadway, except that this requirement shall not apply on Vashon-Maury Island to winery, brewery, distillery facility business locations in use and licensed to produce by the Washington state Liquor and Cannabis Board before January 1, 2019;

j. Off-street parking is limited to a maximum of one hundred fifty percent of the minimum required for winery, brewery, distillery facilities in K.C.C. 21A.18.030;

k. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74;

l. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32 or in compliance with the exemption in K.C.C. 21A.32.110.E.; and

m. The impervious surface associated with the winery, brewery, distillery facility use shall not exceed twenty-five percent of the site, or the maximum impervious surface for the zone in accordance with K.C.C. 21A.12.030.A. or 21A.12.040.A., whichever is less.

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4. Limited to rough milling and planing of products grown on-site with portable equipment.

5. Limited to SIC Industry Group No. 242-Sawmills and SIC Industry No. 2431-Millwork. For RA zoned sites, if using lumber or timber grown off-site, the minimum site area is four and one-half acres.

6. Limited to uses found in SIC Industry No. 2434-Wood Kitchen Cabinets and No. 2431-Millwork, (excluding planing mills).

7. Limited to photocopying and printing services offered to the general public.

8. Only within enclosed buildings, and as an accessory use to retail sales.

9. Only within enclosed buildings.

10. Limited to boat building of craft not exceeding forty-eight feet in length.

11. For I-zoned sites located outside the urban growth area designated by the King County Comprehensive Plan, uses shown as a conditional use in the table of K.C.C. 21A.08.080.A. shall be prohibited, and all other uses shall be subject to the provisions for rural industrial uses as set forth in K.C.C. chapter 21A.12.

12.a. In the A zone, only allowed on sites where the primary use is SIC Industry Group No. 01-Growing and Harvesting Crops or No. 02-Raising Livestock and Small Animals;

b. The aggregated floor area of structures and areas for winery, brewery, distillery facility uses shall not exceed a total of eight thousand square feet. Decks that are not occupied and not open to the public are excluded from the calculation for maximum aggregated floor area;

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c. Only allowed on lots of at least four and one-half acres. If the aggregated floor area of structures for winery, brewery, distillery uses exceeds six thousand square feet, the minimum site area shall be ten acres;

d. Wineries, breweries and distilleries shall comply with Washington state Department of Ecology and King County board of health regulations for water usage and wastewater disposal, and must connect to an existing Group A water system. The definitions and limits of Group A water systems are described in K.C.C. 13.24.007, and provision of water service is described in K.C.C. 13.24.138, 13.24.140 and 13.24.142;

e. Structures and parking areas for winery, brewery distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

f. In the A Zone, sixty percent or more of the products processed must be grown on-site. At the time of the initial application under K.C.C. chapter 6.74, the applicant shall submit a projection of the source of products to be processed;

g. At least two stages of production of wine, beer, cider or distilled spirits, such as crushing, fermenting, distilling, barrel or tank aging, or finishing, as authorized by the Washington state Liquor and Cannabis Board production license, shall occur on-site. At least one of the stages of on-site production shall include crushing, fermenting or distilling;

h. In the A zone, structures and areas for non-agricultural winery, brewery, distillery facility uses shall be located on portions of agricultural lands that are unsuitable for agricultural purposes, such as areas within the already developed portion of such

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agricultural lands that are not available for direct agricultural production, or areas without prime agricultural soils. No more than one acre of agricultural land may be converted to a nonagricultural accessory use;

i. Tasting and retail sales of products produced on-site may occur only as accessory to the primary winery, brewery, distillery production use and may be provided in accordance with state law. The area devoted to on-site tasting or retail sales shall be limited to no more than thirty percent of the aggregated floor area and shall be included in the aggregated floor area limitation in subsection B.12.b. and c. of this section. Incidental retail sales of merchandise related to the products produced on-site is allowed subject to the restrictions described in this subsection. Hours of operation for on-site tasting of products shall be limited as follows: Mondays, Tuesdays, Wednesdays and Thursdays, tasting room hours shall be limited to 11:00 a.m. through 7:00 p.m.; and Fridays, Saturdays and Sundays, tasting room hours shall be limited to 11:00 a.m. through 9:00 p.m.;

j. Access to the site shall be directly to and from an arterial roadway;

k. Off-street parking maximums shall be determined through the conditional use permit process, and should not be more than one hundred fifty percent of the minimum required for winery, brewery, distillery facilities in K.C.C. 21A.18.030;

l. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74;

m. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32 or in compliance with the exemption in K.C.C. 21A.32.110.E.; and

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n. The impervious surface associated with the winery, brewery, distillery facility use shall not exceed twenty-five percent of the site, or the maximum impervious surface for the zone in accordance with K.C.C. 21A.12.030.A. or 21A.12.040.A., whichever is less.

13. Only on the same lot or same group of lots under common ownership or documented legal control, which includes, but is not limited to, fee simple ownership, a long-term lease or an easement:

a. as accessory to a primary forestry use and at a scale appropriate to process the organic waste generated on the site; or

b. as a continuation of a sawmill or lumber manufacturing use only for that period to complete delivery of products or projects under contract at the end of the sawmill or lumber manufacturing activity.

14. Only on the same lot or same group of lots under common ownership or documented legal control, which includes, but is not limited to, fee simple ownership, a long-term lease or an easement:

a. as accessory to a primary mineral use; or

b. as a continuation of a mineral processing use only for that period to complete delivery of products or projects under contract at the end of mineral extraction.

15. Continuation of a materials processing facility after reclamation in accordance with an approved reclamation plan.

16. Only a site that is ten acres or greater and that does not use local access streets that abut lots developed for residential use.

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17.a. The aggregated floor area of structures and areas for winery, brewery, distillery facility uses shall not exceed three thousand five hundred square feet, unless located in whole or in part in a structure designated as historic resource under K.C.C. chapter 20.62, in which case the aggregated floor area of structures and areas devoted to winery, brewery, distillery facility uses shall not exceed five thousand square feet. Decks that are not occupied and not open to the public are excluded from the calculation for maximum aggregated floor area;

b. Structures and parking areas for winery, brewery, distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

c. Tasting and retail sale of products produced on-site, and merchandise related to the products produced on-site, may be provided in accordance with state law. The area devoted to on-site tasting or retail sales shall be included in the aggregated floor area limitation in subsection B.17.a. of this section;

d. Off-street parking for the tasting and retail areas shall be limited to a maximum of one space per fifty square feet of tasting and retail areas;

e. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74; and

f. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32.

18. Limited to:

a. SIC Industry Group No. 242-Sawmills and SIC Industry No. 2431-

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Millwork, as follows:

(1) If using lumber or timber grown off-site, the minimum site area is four and one-half acres;

(2) The facility shall be limited to an annual production of no more than one hundred fifty thousand board feet;

(3) Structures housing equipment used in the operation shall be located at least one-hundred feet from adjacent properties with residential or rural area zoning;

(4) Deliveries and customer visits shall be limited to the hours of 8:00 a.m. to 7:00 p.m. on weekdays, and 9:00 a.m. to 5:00 p.m. on weekends;

(5) In the RA zone, the facility's driveway shall have adequate entering sight distance required by the 2007 King County Road Design and Construction Standards. An adequate turn around shall be provided on-site to prevent vehicles from backing out on to the roadway that the driveway accesses; and

(6) Outside lighting is limited to avoid off-site glare; and

b. SIC Industry No. 2411-Logging.

19. Limited to manufacture of custom made wood furniture or cabinets.

20.a. Only allowed on lots of at least four and one-half acres;

b. Only as an accessory use to a Washington state Liquor Control Board licensed marijuana production facility on the same lot;

c. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

d. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound

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Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

e. Accessory marijuana processing uses allowed under this section are subject to all limitations applicable to marijuana production uses under K.C.C. 21A.08.090.

21.a. Only in the CB and RB zones located outside the urban growth area;

b. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Per lot, the aggregated total gross floor area devoted to the use of, and in support of, processing marijuana together with any separately authorized production of marijuana shall be limited to a maximum of two thousand square feet; and

e. If the two-thousand-square-foot-per-lot threshold is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square-foot threshold area on that lot shall obtain a conditional use permit as set forth in subsection B.22. of this section.

22.a. Only in the CB and RB zones located outside the urban growth area;

b. Per lot, the aggregated total gross floor area devoted to the use of, and in support of, processing marijuana together with any separately authorized production of marijuana shall be limited to a maximum of thirty thousand square feet;

c. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.; and

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d. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site.

23.a. Only in the CB and RB zones located inside the urban growth area;

b. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Per lot, the aggregated total gross floor area devoted to the use of, and in support of, processing marijuana together with any separately authorized production of marijuana shall be limited to a maximum of two thousand square feet; and

e. If the two-thousand-square-foot-per-lot threshold is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square-foot threshold area on that lot shall obtain a conditional use permit as set forth in subsection B.24. of this section.

24.a. Only in the CB and RB zones located inside the urban growth area;

b. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either

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marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

d. Per lot, the aggregated total gross floor area devoted to the use of, and in support of, processing marijuana together with any separately authorized production of marijuana shall be limited to a maximum of thirty thousand square feet.

25.a. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

b. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

c. Per lot, limited to a maximum aggregate total of two thousand square feet of gross floor area devoted to, and in support of, the processing of marijuana together with any separately authorized production of marijuana.

26.a. With a lighting plan, only if required by K.C.C. 21A.12.220.((~~G.~~))H.;

b. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

c. Per lot, limited to a maximum aggregate total of thirty thousand square feet of gross floor area devoted to, and in support of, the processing of marijuana together with

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any separately authorized production of marijuana.

27.a. Marijuana processors in all RA zoned areas except for Vashon-Maury Island, that do not require a conditional use permit issued by King County, that receive a Washington state Liquor and Cannabis Board license business prior to October 1, 2016, and that King County did not object to within the Washington state Liquor and Cannabis Board marijuana license application process, shall be considered nonconforming as to subsection B.27.e. of this section, subject to the provisions of K.C.C. 21A.32.020 through 21A.32.075 for nonconforming uses;

b. Only with a lighting plan that complies with K.C.C. 21A.12.220.((~~G.~~))H:;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Only allowed on lots of at least four and on-half acres on Vashon-Maury Island;

e. Only allowed in the RA-10 or the RA-20 zone, on lots of at least ten acres, except on Vashon-Maury Island;

f. Only as an accessory use to a Washington state Liquor Cannabis Board licensed marijuana production facility on the same lot; and

g. Accessory marijuana processing uses allowed under this section are subject to all limitations applicable to marijuana production uses under K.C.C. 21A.08.090.

28. If the food and kindred products manufacturing or processing is associated

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with agricultural activities it will be reviewed in accordance with K.C.C. 21A.08.090.

29.a. Tasting and retail sales of products produced on-site, and merchandise related to the products produced on-site, may be provided in accordance with state law;

b. Structures and parking areas for winery, brewery, distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

c. For winery, brewery, distillery facility uses that do not require a conditional use permit, off-street parking for the tasting and retail areas shall be limited to a maximum of one space per fifty square feet of tasting and retail areas. For winery, brewery, distillery facility uses that do require a conditional use permit, off-street parking maximums shall be determined through the conditional use permit process, and off-street parking for the tasting and retail areas should be limited to a maximum of one space per fifty square feet of tasting and retail areas;

d. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74; and

e. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32.

30.a. Only allowed on lots of at least two and one-half acres;

b. The aggregated floor area of structures and areas for winery, brewery, distillery facility uses shall not exceed three thousand five hundred square feet, unless located in whole or in part in a structure designated as historic resource under K.C.C. chapter 20.62, in which case the aggregated floor area of structures and areas devoted to

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winery, brewery, distillery facility uses shall not exceed five thousand square feet. Decks that are not occupied and not open to the public are excluded from the calculation for maximum aggregated floor area;

c. Structures and parking areas for winery, brewery, distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

d. Tasting and retail sales of products produced on-site may only occur as accessory to the primary winery, brewery, distillery production use and may be provided in accordance with state law. The area devoted to on-site tasting or retail sales shall be limited to no more than thirty percent of the aggregated floor area and shall be included in the aggregated floor area limitation in subsection B.30.b. of this section. Incidental retail sales of merchandise related to the products produced on-site is allowed subject to the restrictions described in this subsection. Hours of operation for on-site tasting of products shall be limited as follows: Mondays, Tuesdays, Wednesdays and Thursdays, tasting room hours shall be limited to 11:00 a.m. through 7:00 p.m.; and Fridays, Saturdays and Sundays, tasting room hours shall be limited to 11:00 a.m. through 9:00 p.m.;

e. Access to the site shall be directly to and from a public roadway;

f. Off-street parking is limited to a maximum of one hundred fifty percent of the minimum required for winery, brewery, distillery facilities in K.C.C. 21A.18.030;

g. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74;

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h. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32 or in compliance with the exemption in K.C.C. 21A.32.110.E.;

i. At least two stages of production of wine, beer, cider or distilled spirits, such as crushing, fermenting, distilling, barrel or tank aging, or finishing, as authorized by the Washington state Liquor and Cannabis Board production license, shall occur on-site. At least one of the stages of production occurring on-site shall include crushing, fermenting or distilling; and

j. The impervious surface associated with the winery, brewery, distillery facility use shall not exceed twenty-five percent of the site, or the maximum impervious surface for the zone in accordance with K.C.C. 21A.12.030.A. or 21A.12.040.A., whichever is less.

31.a. Limited to businesses with non-retail brewery and distillery production licenses from the Washington state Liquor and Cannabis board. Wineries and remote tasting rooms for wineries shall not be allowed;

b. Tasting and retail sale of products produced on-site and merchandise related to the products produced on-site may be provided in accordance with state law. The area devoted to on-site tasting or retail sales shall not exceed one thousand five hundred square feet;

c. Structures and parking areas for brewery and distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

d. For brewery and distillery facility uses that do not require a conditional use

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permit, off-street parking for the tasting and retail areas shall be limited to a maximum of one space per fifty square feet of tasting and retail areas. For brewery and distillery facility uses that do require a conditional use permit, off-street parking maximums shall be determined through the conditional use permit process, and off-street parking for the tasting and retail areas should be limited to a maximum of one space per fifty square feet of tasting and retail areas;

e. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74; and

f. Events may be allowed with an approved temporary use permit under K.C.C. chapter 21A.32.

32.a. The aggregated floor area of structures and areas for winery, brewery, distillery facility uses shall not exceed one thousand five hundred square feet;

b. Structures and parking areas for winery, brewery, distillery facility uses shall maintain a minimum distance of seventy-five feet from interior property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

c. One on-site parking stall shall be allowed for the winery, brewery, distillery facility I use;

d. The business operator shall obtain an adult beverage business license in accordance with K.C.C. chapter 6.74;

e. At least two stages of production of wine, beer, cider or distilled spirits, such as crushing, fermenting, distilling, barrel or tank aging, or finishing, as authorized by the Washington state Liquor and Cannabis Board production license, shall occur on-site. At

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least one of the stages of production occurring on-site shall include crushing, fermenting or distilling;

f. No product tasting or retail sales shall be allowed on-site;

g. Events may be allowed in accordance with K.C.C. 21A.32.120.B.6; and

h. The impervious surface associated with the winery, brewery, distillery facility use shall not exceed twenty-five percent of the site or the maximum impervious surface for the zone in accordance with K.C.C. 21A.12.030.A. or 21A.12.040.A., whichever is less.

SECTION 9. Ordinance 10870, Section 336, as amended, and K.C.C. 21A.08.090 are each hereby amended as follows:

A. Resource land uses.

P-Permitted Use **C-Conditional Use** **S-Special Use**		**RESOURCE**			**RURAL**	**RESIDENTIAL**			**COMMERCIAL/INDUSTRIAL**				
SIC#	**SPECIFIC LAND USE**	**A**	**F**	**M**	**RA**	**UR**	**R1-8**	**R12-48**	**NB**	**CB**	**RB**	**O**	**I**
12	Coal Mining												
13	Oil and Gas Extraction												
	AGRICULTURE:												
01	Growing and Harvesting Crops	P	P		P	P	P						P
02	Raising Livestock	P	P		P	P							P

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	and Small Animals (6)												
*	Agricultural Activities	P24C	P24C		P24C	P24C							
*	Agricultural Support Services	P25C	P25C		P26C	P26C	P26C		P27C28	P27C28			
*	Marijuana producer	P15C22			P16C17					P18C19	P18C19		P20C21
*	Agriculture Training Facility	C10											
*	Agriculture-related special needs camp	P12											
*	Agricultural Anaerobic Digester	P13											
	FORESTRY:												
08	Growing & Harvesting Forest Production	P	P	P7	P	P	P						P
*	Forest Research		P		P	P						P2	P
	FISH AND WILDLIFE MANAGEMENT:												
0921	Hatchery/Fish Preserve (1)	P	P		P	P	C						P
0273	Aquaculture (1)	P	P		P	P	C						P
*	Wildlife Shelters	P	P		P	P							
	MINERAL:												
10, 14	Mineral Extraction		P9	P									

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	and Processing		C	C1 1									
2951, 3271, 3273	Asphalt/Concrete Mixtures and Block		P8 C1 1	P8 C1 1									P
	ACCESSORY USES:												
*	Resource Accessory Uses	P3 P2 3 P2 9	P4 P2 9	P5 P2 9	P3 P29	P3 P29							P4 P29
*	Farm Worker Housing	P1 4			P14								

B. Development conditions.

1. May be further subject to K.C.C. chapter 21A.25.

2. Only forest research conducted within an enclosed building.

3. Farm residences in accordance with K.C.C. 21A.08.030.

4. Excluding housing for agricultural workers.

5. Limited to either maintenance or storage facilities, or both, in conjunction with mineral extraction or processing operation.

6. Allowed in accordance with K.C.C. chapter 21A.30.

7. Only in conjunction with a mineral extraction site plan approved in accordance with K.C.C. chapter 21A.22.

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8. Only on the same lot or same group of lots under common ownership or documented legal control, which includes, but is not limited to, fee simple ownership, a long-term lease or an easement:

a. as accessory to a primary mineral extraction use;

b. as a continuation of a mineral processing only for that period to complete delivery of products or projects under contract at the end of a mineral extraction; or

c. for a public works project under a temporary grading permit issued in accordance with K.C.C. 16.82.152.

9. Limited to mineral extraction and processing:

a. on a lot or group of lots under common ownership or documented legal control, which includes but is not limited to, fee simple ownership, a long-term lease or an easement;

b. that are located greater than one-quarter mile from an established residence; and

c. that do not use local access streets that abut lots developed for residential use.

10. Agriculture training facilities are allowed only as an accessory to existing agricultural uses and are subject to the following conditions:

a. The impervious surface associated with the agriculture training facilities shall comprise not more than ten percent of the allowable impervious surface permitted under K.C.C. 21A.12.040;

b. New or the expansion of existing structures, or other site improvements, shall not be located on class 1, 2 or 3 soils;

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c. The director may require reuse of surplus structures to the maximum extent practical;

d. The director may require the clustering of new structures with existing structures;

e. New structures or other site improvements shall be set back a minimum distance of seventy-five feet from property lines adjoining rural area and residential zones;

f. Bulk and design of structures shall be compatible with the architectural style of the surrounding agricultural community;

g. New sewers shall not be extended to the site;

h. Traffic generated shall not impede the safe and efficient movement of agricultural vehicles, nor shall it require capacity improvements to rural roads;

i. Agriculture training facilities may be used to provide educational services to the surrounding rural/agricultural community or for community events. Property owners may be required to obtain a temporary use permit for community events in accordance with K.C.C. chapter 21A.32;

j. Use of lodging and food service facilities shall be limited only to activities conducted in conjunction with training and education programs or community events held on site;

k. Incidental uses, such as office and storage, shall be limited to those that directly support education and training activities or farm operations; and

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l. The King County agriculture commission shall be notified of and have an opportunity to comment upon all proposed agriculture training facilities during the permit process in accordance with K.C.C. chapter 21A.40.

11. Continuation of mineral processing and asphalt/concrete mixtures and block uses after reclamation in accordance with an approved reclamation plan.

12.a. Activities at the camp shall be limited to agriculture and agriculture-oriented activities. In addition, activities that place minimal stress on the site's agricultural resources or activities that are compatible with agriculture are permitted.

(1) passive recreation;

(2) training of individuals who will work at the camp;

(3) special events for families of the campers; and

(4) agriculture education for youth.

b. Outside the camp center, as provided for in subsection B.12.e. of this section, camp activities shall not preclude the use of the site for agriculture and agricultural related activities, such as the processing of local food to create value-added products and the refrigeration and storage of local agricultural products. The camp shall be managed to coexist with agriculture and agricultural activities both onsite and in the surrounding area.

c. A farm plan shall be required for commercial agricultural production to ensure adherence to best management practices and soil conservation.

d.(1) The minimum site area shall be five hundred acres. Unless the property owner has sold or transferred the development rights as provided in subsection B.12.c.(3) of this section, a minimum of five hundred acres of the site must be owned by a single

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individual, corporation, partnership, or other legal entity and must remain under the ownership of a single individual, corporation, partnership, or other legal entity for the duration of the operation of the camp.

(2) Nothing in subsection B.12.d.(1) of this section prohibits the property owner from selling or transferring the development rights for a portion or all of the site to the King County farmland preservation program or, if the development rights are extinguished as part of the sale or transfer, to a nonprofit entity approved by the director;

e. The impervious surface associated with the camp shall comprise not more than ten percent of the allowable impervious surface permitted under K.C.C. 21A.12.040;

f. Structures for living quarters, dining facilities, medical facilities, and other nonagricultural camp activities shall be located in a camp center. The camp center shall be no more than fifty acres and shall depicted on a site plan. New structures for nonagricultural camp activities shall be clustered with existing structures;

g. To the extent practicable, existing structures shall be reused. The applicant shall demonstrate to the director that a new structure for nonagricultural camp activities cannot be practicably accommodated within an existing structure on the site, though cabins for campers shall be permitted only if they do not already exist on site;

h. Camp facilities may be used to provide agricultural educational services to the surrounding rural and agricultural community or for community events. If required by K.C.C. chapter 21A.32, the property owner shall obtain a temporary use permit for community events;

i. Lodging and food service facilities shall only be used for activities related to the camp or for agricultural education programs or community events held on site;

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j. Incidental uses, such as office and storage, shall be limited to those that directly support camp activities, farm operations, or agricultural education programs;

k. New nonagricultural camp structures and site improvements shall maintain a minimum set-back of seventy-five feet from property lines adjoining rural area and residential zones;

l. Except for legal nonconforming structures existing as of January 1, 2007, camp facilities, such as a medical station, food service hall, and activity rooms, shall be of a scale to serve overnight camp users;

m. Landscaping equivalent to a type III landscaping screen, as provided for in K.C.C. 21A.16.040, of at least twenty feet shall be provided for nonagricultural structures and site improvements located within two hundred feet of an adjacent rural area and residential zoned property not associated with the camp;

n. New sewers shall not be extended to the site;

o. The total number of persons staying overnight shall not exceed three hundred;

p. The length of stay for any individual overnight camper, not including camp personnel, shall not exceed ninety days during a three-hundred-sixty-five-day period;

q. Traffic generated by camp activities shall not impede the safe and efficient movement of agricultural vehicles nor shall it require capacity improvements to rural roads;

r. If the site is adjacent to an arterial roadway, access to the site shall be directly onto the arterial unless the county road engineer determines that direct access is unsafe;

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s. If direct access to the site is via local access streets, transportation management measures shall be used to minimize adverse traffic impacts;

t. Camp recreational activities shall not involve the use of motor vehicles unless the motor vehicles are part of an agricultural activity or are being used for the transportation of campers, camp personnel, or the families of campers. Camp personnel may use motor vehicles for the operation and maintenance of the facility. Client-specific motorized personal mobility devices are allowed; and

u. Lights to illuminate the camp or its structures shall be arranged to reflect the light away from any adjacent property.

13. Limited to digester receiving plant and animal and other organic waste from agricultural activities, and including electrical generation, as follows:

a. the digester must be included as part of a Washington state Department of Agriculture approved dairy nutrient plan;

b. the digester must process at least seventy percent livestock manure or other agricultural organic material from farms in the vicinity, by volume;

c. imported organic waste-derived material, such as food processing waste, may be processed in the digester for the purpose of increasing methane gas production for beneficial use, but not shall exceed thirty percent of volume processed by the digester; and

d. the use must be accessory to an operating dairy or livestock operation.

14. Farm worker housing. Either:

a. Temporary farm worker housing subject to the following conditions:

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(1) The housing must be licensed by the Washington state Department of Health under chapter 70.114A RCW and chapter 246-358 WAC;

(2) Water supply and sewage disposal systems must be approved by the Seattle King County department of health;

(3) To the maximum extent practical, the housing should be located on nonfarmable areas that are already disturbed and should not be located in the floodplain or in a critical area or critical area buffer; and

(4) The property owner shall file with the department of executive services, records and licensing services division, a notice approved by the department identifying the housing as temporary farm worker housing and that the housing shall be occupied only by agricultural employees and their families while employed by the owner or operator or on a nearby farm. The notice shall run with the land; or

b. Housing for agricultural employees who are employed by the owner or operator of the farm year-round as follows:

(1) Not more than:

(a) one agricultural employee dwelling unit on a site less than twenty acres;

(b) two agricultural employee dwelling units on a site of at least twenty acres and less than fifty acres;

(c) three agricultural employee dwelling units on a site of at least fifty acres and less than one-hundred acres; and

(d) four agricultural employee dwelling units on a site of at least one-hundred acres, and one additional agricultural employee dwelling unit for each additional one hundred acres thereafter;

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(2) If the primary use of the site changes to a nonagricultural use, all agricultural employee dwelling units shall be removed;

(3) The applicant shall file with the department of executive services, records and licensing services division, a notice approved by the department that identifies the agricultural employee dwelling units as accessory and that the dwelling units shall only be occupied by agricultural employees who are employed by the owner or operator year-round. The notice shall run with the land. The applicant shall submit to the department proof that the notice was filed with the department of executive services, records and licensing services division, before the department approves any permit for the construction of agricultural employee dwelling units;

(4) An agricultural employee dwelling unit shall not exceed a floor area of one thousand square feet and may be occupied by no more than eight unrelated agricultural employees;

(5) To the maximum extent practical, the housing should be located on nonfarmable areas that are already disturbed;

(6) One off-street parking space shall be provided for each agricultural employee dwelling unit; and

(7) The agricultural employee dwelling units shall be constructed in compliance with K.C.C. Title 16.

15. Marijuana production by marijuana producers licensed by the Washington state Liquor and Cannabis Board is subject to the following standards:

a. Only allowed on lots of at least four and one-half acres;

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b. With a lighting plan, only if required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Production is limited to outdoor, indoor within marijuana greenhouses, and within structures that are nondwelling unit structures that exist as of October 1, 2013, subject to the size limitations in subsection B.15.e. of this section;

e. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080 shall be limited to a maximum aggregated total of two thousand square feet and shall be located within a fenced area or marijuana greenhouse that is no more than ten percent larger than that combined area, or may occur in nondwelling unit structures that exist as of October 1, 2013;

f. Outdoor production area fencing as required by the Washington state Liquor and Cannabis Board, marijuana greenhouses and nondwelling unit structures shall maintain a minimum street setback of fifty feet and a minimum interior setback of thirty feet; and

g. If the two-thousand-square-foot-per-lot threshold of plant canopy combined with area used for processing under K.C.C. 21A.08.080 is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square-foot

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threshold area on that lot shall obtain a conditional use permit as set forth in subsection B.22. of this section.

16. Marijuana production by marijuana producers licensed by the Washington state Liquor and Cannabis Board is subject to the following standards:

a. Marijuana producers in all RA zoned areas except for Vashon-Maury Island, that do not require a conditional use permit issued by King County, that receive a Washington state Liquor and Cannabis Board license business before October 1, 2016, and that King County did not object to within the Washington state Liquor and Cannabis Board marijuana license application process, shall be considered nonconforming as to subsection B.16.d. and h. of this section, subject to the provisions of K.C.C. 21A.32.020 through 21A.32.075 for nonconforming uses;

b. In all rural area zones, only with a lighting plan that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only allowed on lots of at least four and one-half acres on Vashon-Maury Island;

d. Only allowed in the RA-10 or the RA-20 zone, on lots of at least ten acres, except on Vashon-Maury Island;

e. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

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f. Production is limited to outdoor, indoor within marijuana greenhouses, and within nondwelling unit structures that exist as of October 1, 2013, subject to the size limitations in subsection B.16.g. of this section; and

g. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080 shall be limited to a maximum aggregated total of two thousand square feet and shall be located within a fenced area or marijuana greenhouse, that is no more than ten percent larger than that combined area, or may occur in nondwelling unit structures that exist as of October 1, 2013;

h. Outdoor production area fencing as required by the Washington state Liquor and Cannabis Board and marijuana greenhouses shall maintain a minimum street setback of fifty feet and a minimum interior setback of one hundred feet; and a minimum setback of one hundred fifty feet from any existing residence; and

i. If the two-thousand-square-foot-per-lot threshold of plant canopy within fenced areas or marijuana greenhouses is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square-foot threshold area on that lot shall obtain a conditional use permit as set forth in subsection B.17. of this section.

17. Marijuana production by marijuana producers licensed by the Washington state Liquor and Cannabis Board is subject to the following standards:

a. Only allowed on lots of at least four and one-half acres on Vashon-Maury Island;

b. Only allowed in the RA-10 or the RA-20 zone, on lots of at least ten acres, except on Vashon-Maury Island;

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c. In all rural area zones, only with a lighting plan that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

d. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

e. Production is limited to outdoor and indoor within marijuana greenhouses subject to the size limitations in subsection B.17.f. of this section;

f. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080 shall be limited to a maximum aggregated total of thirty thousand square feet and shall be located within a fenced area or marijuana greenhouse that is no more than ten percent larger than that combined area; and

g. Outdoor production area fencing as required by the Washington state Liquor and Cannabis Board, and marijuana greenhouses shall maintain a minimum street setback of fifty feet and a minimum interior setback of one hundred feet, and a minimum setback of one hundred fifty feet from any existing residence.

18.a. Production is limited to indoor only;

b. With a lighting plan only as required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either

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marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

d. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080, shall be limited to a maximum aggregated total of two thousand square feet and shall be located within a building or tenant space that is no more than ten percent larger than the plant canopy and separately authorized processing area; and

e. If the two-thousand-square-foot-per-lot threshold is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square foot threshold area on that parcel shall obtain a conditional use permit as set forth in subsection B.19. of this section.

19.a. Production is limited to indoor only;

b. With a lighting plan only as required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

d. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080, shall be limited to a maximum aggregated total of thirty thousand square feet and shall be located within a building or

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tenant space that is no more than ten percent larger than the plant canopy and separately authorized processing area.

20.a. Production is limited to indoor only;

b. With a lighting plan only as required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080, shall be limited to a maximum aggregated total of two thousand square feet and shall be located within a building or tenant space that is no more than ten percent larger than the plant canopy and separately authorized processing area; and

e. If the two-thousand-square-foot-per-lot threshold is exceeded, each and every marijuana-related entity occupying space in addition to the two-thousand-square-foot threshold area on that lot shall obtain a conditional use permit as set forth in subsection B.21. of this section.

21.a. Production is limited to indoor only;

b. With a lighting plan only as required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

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c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site; and

d. Per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080, shall be limited to a maximum aggregated total of thirty thousand square feet and shall be located within a building or tenant space that is no more than ten percent larger than the plant canopy and separately authorized processing area.

22. Marijuana production by marijuana producers licensed by the Washington state Liquor and Cannabis Board is subject to the following standards:

a. With a lighting plan only as required by and that complies with K.C.C. 21A.12.220.((~~G.~~))H.;

b. Only allowed on lots of at least four and one-half acres;

c. Only with documentation that the operator has applied for a Puget Sound Clean Air Agency Notice of Construction Permit. All department permits issued to either marijuana producers or marijuana processors, or both, shall require that a Puget Sound Clean Air Agency Notice of Construction Permit be approved before marijuana products are imported onto the site;

d. Production is limited to outdoor, indoor within marijuana greenhouses, and within structures that are nondwelling unit structures that exist as of October 1, 2013, subject to the size limitations in subsection B.22. e. and f. of this section;

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e. On lots less than ten acres, per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080 shall be limited to a maximum aggregated total of five thousand square feet and shall be located within a fenced area or marijuana greenhouse that is no more than ten percent larger than that combined area, or may occur in nondwelling unit structures that exist as of October 1, 2013;

f. On lots ten acres or more, per lot, the plant canopy, as defined in WAC 314-55-010, combined with any area used for processing under K.C.C. 21A.08.080 shall be limited to a maximum aggregated total of ten thousand square feet, and shall be located within a fenced area or marijuana greenhouse that is no more than ten percent larger than that combined area, or may occur in nondwelling unit structures that exist as of October 1, 2013; and

g. Outdoor production area fencing as required by the Washington state Liquor and Cannabis Board, marijuana greenhouses and nondwelling unit structures shall maintain a minimum street setback of fifty feet and a minimum interior setback of one hundred feet, and a minimum setback of one hundred fifty feet from any existing residence.

23. The storage and processing of non-manufactured source separated organic waste that originates from agricultural operations and that does not originate from the site, if:

a. agricultural is the primary use of the site;

b. the storage and processing are in accordance with best management practices included in an approved farm plan; and

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c. except for areas used for manure storage, the areas used for storage and processing do not exceed three acres and ten percent of the site.

24.a. For activities relating to the processing of crops or livestock for commercial purposes, including associated activities such as warehousing, storage, including refrigeration, and other similar activities and excluding winery, brewery, distillery facility I, II, III and remote tasting room:

(1) limited to agricultural products and sixty percent or more of the products processed must be grown in the Puget Sound counties. At the time of initial application, the applicant shall submit a projection of the source of products to be produced;

(2) in the RA and UR zones, only allowed on sites of at least four and one-half acres;

(3)(a) as a permitted use, the floor area devoted to all processing shall not exceed two thousand square feet, unless located in a building designated as an historic resource under K.C.C. chapter 20.62. The agricultural technical review committee, as established in K.C.C. 21A.42.300, may review and approve an increase in the processing floor area as follows: up to three thousand five hundred square feet of floor area may be devoted to all processing in the RA zones or on farms less than thirty-five acres located in the A zones or up to seven thousand square feet on farms greater than thirty-five acres in the A zone; and

(b) as a permitted use, the floor area devoted to all warehousing, refrigeration, storage, or other similar activities shall not exceed two thousand square feet, unless located in a building designated as historic resource under K.C.C. chapter 20.62. The agricultural technical review committee, as established in K.C.C.

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21A.42.300, may review and approve an increase of up to three thousand five hundred square feet of floor area devoted to all warehouseing, storage, including refrigeration, or other similar activities in the RA zones, or on farms less than thirty-five acres located in the A zones, or up to seven thousand square feet on farms greater than thirty-five acres in the A zone;

(4) in the A zone, structures and areas used for processing, warehousing, ((~~refigeration~~)) refrigeration, storage, and other similar activities shall be located on portions of agricultural lands that are unsuitable for other agricultural purposes, such as areas within the already developed portion of such agricultural lands that are not available for direct agricultural production, or areas without prime agricultural soils; and

(5) structures and areas used for processing, warehousing, storage, including refrigeration, and other similar activities shall maintain a minimum distance of seventy-five feet from property lines adjoining rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62.

b. For activities relating to the retail sale of agricultural products, except livestock:

(1) sales shall be limited to agricultural products and locally made arts and crafts;

(2) in the RA and UR zones, only allowed on sites at least four and one-half acres;

(3) as a permitted use, the covered sales area shall not exceed two thousand square feet, unless located in a building designated as a historic resource under K.C.C. chapter 20.62. The agricultural technical review committee, as established in K.C.C.

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21A.42.300, may review and approve an increase of up to three thousand five hundred square feet of covered sales area;

(4) forty percent or more of the gross sales of agricultural product sold through the store must be sold by the producers of primary agricultural products;

(5) sixty percent or more of the gross sales of agricultural products sold through the store shall be derived from products grown or produced in the Puget Sound counties. At the time of the initial application, the applicant shall submit a reasonable projection of the source of product sales;

(6) tasting of products, in accordance with applicable health regulations, is allowed;

(7) storage areas for agricultural products may be included in a farm store structure or in any accessory building; and

(8) outside lighting is permitted if there is no off-site glare.

c. Retail sales of livestock is permitted only as accessory to raising livestock.

d. Farm operations, including equipment repair and related facilities, except that:

(1) the repair of tools and machinery is limited to those necessary for the operation of a farm or forest;

(2) in the RA and UR zones, only allowed on sites of at least four and one-half acres;

(3) the size of the total repair use is limited to one percent of the farm size in the A zone, and up to one percent of the size in other zones, up to a maximum of five

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thousand square feet unless located within an existing farm structure, including but not limited to barns, existing as of December 31, 2003; and

(4) Equipment repair shall not be permitted in the Forest zone.

e. The agricultural technical review committee, as established in K.C.C. 21A.42.300, may review and approve reductions of minimum site sizes in the rural and residential zones and minimum setbacks from rural and residential zones.

25. The department may review and approve establishment of agricultural support services in accordance with the code compliance review process in K.C.C. 21A.42.300 only if:

a. project is sited on lands that are unsuitable for direct agricultural production based on size, soil conditions, or other factors and cannot be returned to productivity by drainage maintenance; and

b. the proposed use is allowed under any Farmland Preservation Program conservation easement and zoning development standards.

26. The agricultural technical review committee, as established in K.C.C. 21A.42.300, may review and approve establishment of agricultural support services only if the project site:

a. adjoins or is within six hundred sixty feet of the agricultural production district;

b. has direct vehicular access to the agricultural production district;

c. except for farmworker housing, does not use local access streets that abut lots developed for residential use; and

b. has a minimum lot size of four and one-half acres.

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27. The agricultural technical review committee, as established in K.C.C. 21A.42.300, may review and approve establishment of agricultural support services only if the project site:

a. is outside the urban growth area,

b. adjoins or is within six hundred sixty feet of the agricultural production district,

c. has direct vehicular access to the agricultural production district,

d. except for farmworker housing, does not use local access streets that abut lots developed for residential use; and

e. has a minimum lot size of four and one-half acres.

28. Only allowed on properties that are outside the urban growth area.

29. Battery energy storage systems are considered a resource accessory use when the total system capacity is two megawatts or less, and:

(1) the system provides electricity for on-site use only, with "on-site use" including net metering as well as charging of vehicles on-site or in the right-of-way immediately adjacent to the site; or

(2) the system is intended primarily for on-site use, but also participates in load sharing or another grid-connected electricity-sharing arrangement.

SECTION 10. Ordinance 10870, Section 337, as amended, and K.C.C. 21A.08.100 are each hereby amended as follows:

A. Regional land uses.

P-Permitted Use C-Conditional Use	RESOURCE	R U	RESIDENTIAL	COMMERCIAL/INDUSTRIAL

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S-Special Use					**R A L**								
SIC#	**SPECIFIC LAND USE**	**A**	**F**	**M**	**RA**	**UR**	**R1-8**	**R12-48**	**NB**	**CB**	**RB**	**O**	**I (15)**
*	Jail						S	S	S	S	S	S	S
*	Jail Farm/Camp	S	S		S	S							
*	Work Release Facility				S19	S19	S	S	S	S	S	S	
*	Public Agency Animal Control Facility		S		S	S					S		P
*	Public Agency Training Facility		S		S3					S3	S3	S3	C4
*	Hydroelectric Generation Facility		C14 S		C14 S	C14 S	C14 S						
((*))	((~~Search and Rescue Facility~~))				((~~C 30 S30~~))								
*	Non((-))hydroelectric Generation Facility	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	C12 S29	P12 S29
*	Renewable Energy Generation Facility	C28	C28	C	C	C	C	C	C	C	C	C	C
*	Fossil Fuel Facility												S27
*	Battery Energy Storage System (30)		S	P	P	P	C	C	P	P	P	P	P
*	Communication Facility (17)	C6c S	P		C6c S	C6c S	C6c S	C6c S	C6c S	P	P	P	P

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*	Earth Station	P6b C	P		C6a S	C6a S	C6a S	C6a S	P6b C	P	P	P	P
*	Energy Resource Recovery Facility		S	S	S	S	S	S	S	S	S	S	S
*	Soil Recycling Facility		S	S	S								C
*	Landfill		S	S	S	S	S	S	S	S	S	S	S
*	Transfer Station			S	S	S	S	S	S	S	S		P
*	Wastewater Treatment Facility				S	S	S	S	S	S	S	S	C
*	Municipal Water Production	S	P13 S	S	S	S	S	S	S	S	S	S	S
*	Airport/Heliport	S7	S7		S	S	S	S	S	S	S	S	S
*	Search and Rescue Facility				C31 S31								
*	Regional Transit Authority Facility					P25							
*	Rural Public Infrastructure Maintenance Facility				C23								P
*	Transit Bus Base						S	S	S	S	S	S	P
*	Transit Comfort Facility				P26		P26	P26	P26	P26	P26	P26	P26
*	School Bus Base				C5 S20	C5 S	C5 S	C5 S	S	S	S	S	P
7948	Racetrack				S8	S8	S8	S8	S8	S8	S8	S8	S24
*	Regional Motor Sports Facility												P
*	County Fairgrounds				P21								

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	Facility				S22								
*	Fairground									S	S		S
8422	Zoo/Wildlife Exhibit(2)		S9		S9	S	S	S		S	S		
7941	Stadium/Arena										S		S
8221-8222	College/University(1)	P10	P10		P10 C11 S18	P10 C11 S18	P10 C11 S	P10 C11 S	P10 C11 S	P	P	P	P
*	Zoo Animal Breeding Facility	P16	P16		P16								

B. Development conditions.

1. Except technical institutions. See vocational schools on general services land use table, K.C.C. 21A.08.050.

2. Except arboretum. See K.C.C. 21A.08.040, recreation/cultural land use table.

3. Except weapons armories and outdoor shooting ranges.

4. Except outdoor shooting range.

5. Only in conjunction with an existing or proposed school.

6.a. Limited to no more than three satellite dish antennae.

b. Limited to one satellite dish antenna.

c. Limited to tower consolidations.

7. Limited to landing field for aircraft involved in forestry or agricultural practices or for emergency landing sites.

8. Except racing of motorized vehicles.

9. Limited to wildlife exhibit.

10. Only as a reuse of a public school facility subject to K.C.C. chapter 21A.32.

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11. Only as a reuse of a surplus nonresidential facility subject to K.C.C. chapter 21A.32.

12. Limited to gas extraction as an accessory use to a waste management process, such as wastewater treatment, landfill waste management, livestock manure and composting processes.

13. Excluding impoundment of water using a dam.

14. Limited to facilities that comply with the following:

a. Any new diversion structure shall not:

(1) exceed a height of eight feet as measured from the streambed; or

(2) impound more than three surface acres of water at the normal maximum surface level;

b. There shall be no active storage;

c. The maximum water surface area at any existing dam or diversion shall not be increased;

d. An exceedance flow of no greater than fifty percent in mainstream reach shall be maintained;

e. Any transmission line shall be limited to a:

(1) right-of-way of five miles or less; and

(2) capacity of two hundred thirty KV or less;

f. Any new, permanent access road shall be limited to five miles or less; and

g. The facility shall only be located above any portion of the stream used by anadromous fish.

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15. For I-zoned sites located outside the urban growth area designated by the King County Comprehensive Plan, uses shown as a conditional or special use in K.C.C. 21A.08.100.A, except for waste water treatment facilities and racetracks, shall be prohibited. All other uses, including waste water treatment facilities, shall be subject to the provisions for rural industrial uses in K.C.C. chapter 21A.12.

16. The operator of such a facility shall provide verification to the department of natural resources and parks or its successor organization that the facility meets or exceeds the standards of the Animal and Plant Health Inspection Service of the United States Department of Agriculture and the accreditation guidelines of the American Zoo and Aquarium Association.

17. The following provisions of the table apply only to major communication facilities. Minor communication facilities shall be reviewed in accordance with the processes and standard outlined in K.C.C. chapter 21A.27.

18. Only for facilities related to resource-based research.

19. Limited to work release facilities associated with natural resource-based activities.

20. Limited to projects which do not require or result in an expansion of sewer service outside the urban growth area, unless a finding is made that no cost-effective alternative technologies are feasible, in which case a tightline sewer sized only to meet the needs of the school bus base and serving only the school bus base may be used. Renovation, expansion, modernization, or reconstruction of a school bus base is permitted but shall not require or result in an expansion of sewer service outside the urban growth area, unless a finding is made that no cost-effective alternative technologies

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are feasible, in which case a tightline sewer sized only to meet the needs of the school bus base.

21. Only in conformance with the King County Site Development Plan Report, through modifications to the plan of up to ten percent are allowed for the following:

a. building square footage;

b. landscaping;

c. parking;

d. building height; or

e. impervious surface.

22. A special use permit shall be required for any modification or expansion of the King County fairgrounds facility that is not in conformance with the King County Site Development Plan Report or that exceeds the allowed modifications to the plan identified in subsection B.21. of this section.

23. The facility shall be primarily devoted to rural public infrastructure maintenance and is subject to the following conditions:

a. The minimum site area shall be ten acres, unless:

(1) the facility is a reuse of a public agency yard; or

(2) the site is separated from a county park by a street or utility right-of-way;

b. Type 1 landscaping as provided in K.C.C. chapter 21A.16 shall be provided between any stockpiling or grinding operations and adjacent residential zoned property;

c. Type 2 landscaping as provided in K.C.C. chapter 21A.16 shall be provided between any office and parking lots and adjacent residential zoned property;

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d. Access to the site does not use local access streets that abut residential zoned property, unless the facility is a reuse of a public agency yard;

e. Structural setbacks from property lines shall be as follows:

(1) Buildings, structures, and stockpiles used in the processing of materials shall be no closer than:

(a) one hundred feet from any residential zoned properties, except that the setback may be reduced to fifty feet when the grade where the building or structures are proposed is fifty feet or greater below the grade of the residential zoned property;

(b) fifty feet from any other zoned property, except when adjacent to a mineral extraction or materials processing site;

(c) the greater of fifty feet from the edge of any public street or the setback from residential zoned property on the far side of the street; and

(2) Offices, scale facilities, equipment storage buildings, and stockpiles shall not be closer than fifty feet from any property line except when adjacent to M or F zoned property or when a reuse of an existing building. Facilities necessary to control access to the site, when demonstrated to have no practical alternative, may be located closer to the property line;

f. On-site clearing, grading or excavation, excluding that necessary for required access, roadway, or storm drainage facility construction, shall not be permitted within fifty feet of any property line except along any portion of the perimeter adjacent to M or F zoned property. If native vegetation is restored, temporary disturbance resulting from construction of noise attenuation features located closer than fifty feet shall be permitted; and

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g. Sand and gravel extraction shall be limited to forty thousand yards per year.

24. The following accessory uses to a motor race track operation are allowed if approved as part of the special use permit:

a. motocross;

b. autocross;

c. skidpad;

d. garage;

e. driving school; and

f. fire station.

25. Regional transit authority facilities shall be exempt from setback and height requirements.

26. Transit comfort facility shall:

a. only be located outside of the urban growth area boundary;

b. be exempt from street setback requirements; and

c. be no more than 200 square feet in size.

27.a. Required for all new, modified, or expanded fossil fuel facilities. Modification or expansion includes, but is not limited to:

(1) new uses or fuel types within existing facilities;

(2) changes to the type of refining, manufacturing, or processing;

(3) changes in the methods or volumes of storage or transport of raw materials or processed products;

(4) changes in the location of the facilities on-site;

(5) replacement of existing facilities;

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(6) increases in power or water demands; or

(7) increases in production capacity.

b. Before filing an application with the department, the applicant shall hold a community meeting in accordance with K.C.C. 20.20.035.

c. As part of permit application submittal for new, modified, or expanded fossil fuel facilities, the applicant shall submit the following documentation:

(1) an inventory of similar existing facilities in King County and neighboring counties, including their locations and capacities;

(2) a forecast of the future needs for the facility;

(3) an analysis of the potential social and economic impacts and benefits to jurisdictions and local communities receiving or surrounding the facility;

(4) an analysis of alternatives to the facility, including location, conservation, demand management and other strategies;

(5) an analysis of economic and environmental impacts, including mitigation, of any similar existing facilities and of any new site(s) under consideration as an alternative to expansion of an existing facility;

(6) an extensive public involvement strategy that strives to effectively engage a wide range of racial, ethnic, cultural, and socioeconomic groups, including communities that are the most impacted;

(7) considered evaluation of any applicable prior review conducted by a public agency, local government, or stakeholder group; and

(8) a greenhouse gas impact analysis prepared by the applicant, the results of which shall be used to identify and mitigate the impacts of such facilities.

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d.(((~~(1)~~))) As part of permit application submittal, the applicant shall demonstrate financial responsibility ((~~in an amount necessary to compensate for the cost of decommissioning, and for the maximum damages that might occur from an explosion resulting from a worst-case release, as defined in the 40 C.F.R. Sec. 68.3, of flammable gases and flammable liquids.~~

~~(2) The amount of financial responsibility necessary to compensate for damages that might occur from an explosion shall be determined by the director based on a study of the maximum potential damages. The study shall:~~

~~(a) incorporate the volume of oils, gases, refrigerants and other flammable or explosive chemicals stored, used or generated within the facility;~~

~~(b) consider such matters as: the frequency of facility operations; facility layout and vegetation that could cause flammable vapor accumulation; the damages that could result from the explosion to public and private structures onsite and offsite, public infrastructure and environmental resources and functions; and the potential loss of life and injury to persons onsite and to members of the public;~~

~~(c) include modeling and disclosure of a nil or very low wind condition vapor cloud explosion scenario;~~

~~(d) be prepared by a person accredited in vapor cloud explosion analysis, or an equally qualified individual as authorized by the director, at the applicant's expense; and~~

~~(e) undergo third-party validation by a qualified entity to be hired upon mutual agreement of the applicant and the department, at the applicant's expense.~~

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~~(3) The amount of financial responsibility necessary to compensate for facility decommissioning shall be determined by the director based on a decommissioning plan for the closure of the facility. The plan shall include, but need not be limited to, the following:~~

~~(a) listing of the hazardous substances, as defined in RCW 70A.305.020, that will be stored, handled or generated within the facility; the range of potential release volumes requiring cleanup in the event of failures of technological or safety catchment features; and whether such releases have the potential to contaminate groundwater or surface waters on or adjacent to the site;~~

~~(b) the range of cleanup activities that would be required to address such hazardous substances;~~

~~(c) detailed estimates of the cost to implement the plan, including conducting cleanup and facility closure, based on the cost of hiring a third party to conduct all activities. All cost estimates must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property; and~~

~~(d) methods for estimating closure costs.~~

~~(4)(a) Financial responsibility shall be provided for the duration of fossil fuel facility operations, to be verified in periodic review of the facilities in keeping with K.C.C. chapter 21A.22. Financial responsibility required by this subsection B.27.e. may be established by any one of, or a combination of, the following methods acceptable to the department:~~

~~i. evidence of insurance;~~

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~~ii. surety bonds issued by a bonding company authorized to do business in the United States; and~~

~~iii. other evidence of financial responsibility deemed acceptable by the department.~~

~~(b) Self-bonding, as defined in the 30 C.F.R. Sec. 800.5, shall not be an accepted method of providing financial responsibility.~~

~~(5) Where enforcement of this subsection B.27.e. would conflict with chapter 36.32 RCW, the director may request the applicant to sign an agreement to complete retention of required financial responsibility consistent with K.C.C. 27A.30.060, in an amount equivalent to that indicated by the study of the damages, prior to the issuance of a clearing and grading permit~~)) meeting the requirements of K.C.C. chapter 21A.XX (the new chapter created by section 16 of this ordinance). The financial responsibility shall be reviewed as part of the facility's periodic review under K.C.C. 21A.22.050.

e. New, modified, or expanded fossil fuel facilities shall:

(1) not be located within one thousand feet from any schools, medical care facilities, or places of assembly that have occupancies of greater than one thousand persons;

(2) not be located within two hundred fifty feet from a regulated wetland or aquatic area, except when a larger buffer is required under K.C.C. chapter 21A.24, the buffer in K.C.C. chapter 21A.24 shall apply;

(3) maintain an interior setback of at least two hundred feet;

(4) store fossil fuels completely within enclosed structures, tanks, or similar facilities;

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(5) be accessed directly to and from an arterial roadway; and

(6) comply with all applicable regulations in K.C.C. chapter 21A.22.

28. Limited to uses that will not convert more than two acres of farmland or forestland, or ((~~2.5~~)) two and one-half percent of the farmland or forestland, whichever is less.

29.a. Before filing an application with the department, the applicant shall hold a community meeting in accordance with K.C.C. 20.20.035.

b. As part of permit application submittal for non((-))hydroelectric generation facilities, the applicant shall submit the following documentation:

(1) an inventory of similar existing facilities in King County and neighboring counties, including their locations and capacities;

(2) a report demonstrating that the facility would serve a significant portion of the county or metropolitan region or is part of a statewide or national system;

(3) a forecast of the future needs for the facility;

(4) an analysis of the potential social and economic impacts and benefits to jurisdictions and local communities receiving or surrounding the facility;

(5) an analysis of alternatives to the facility, including location, conservation, demand management, and other strategies;

(6) an analysis of economic and environmental impacts, including mitigation, of any similar existing facilities and of any new site or sites under consideration as an alternative to expansion of an existing facility;

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(7) an extensive public involvement strategy which strives to effectively engage a wide range of racial, ethnic, cultural and socioeconomic groups, including communities that are the most impacted;

(8) considered evaluation of any applicable prior review conducted by a public agency, local government, or stakeholder group; and

(9) a greenhouse gas impact analysis prepared by the applicant, the results of which shall be used to identify and mitigate the impacts of such facilities.

c.(((~~(1)~~))) As part of permit application submittal, an applicant shall demonstrate financial responsibility ((~~in an amount necessary to compensate for decommissioning, and for the maximum damages that might occur from an explosion resulting from a worst-case release, as defined in 40 C.F.R. Sec. 68.3, of flammable gases and flammable liquids.~~

~~(2) The amount of financial responsibility needed to compensate for damages that might occur from an explosion shall be as determined by the director based on a study of the maximum damages. The study shall:~~

~~(a) incorporate the volume of oils, gases, refrigerants and other flammable or explosive chemicals stored, used or generated within the facility;~~

~~(b) consider such matters as: the frequency of facility operations; facility layout and vegetation that could cause flammable vapor accumulation; the damages that could result from the explosion to public and private structures onsite and offsite, public infrastructure and environmental resources and functions; and the potential loss of life and injury to persons onsite and to members of the public;~~

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~~(c) include modeling and disclosure of a nil or very low wind condition vapor cloud explosion scenario;~~

~~(d) be prepared by a person accredited in vapor cloud explosion analysis, or an equally qualified individual as authorized by the director, at the applicant's expense; and~~

~~(e) undergo third-party validation by a qualified entity to be hired upon mutual agreement of the applicant and the department, at the applicant's expense.~~

~~(3) The amount of financial responsibility necessary to compensate for facility decommissioning shall be determined by the director based on a decommissioning plan for the closure of the facility. The plan shall include, but need not be limited to, the following:~~

~~(a) listing of the hazardous substances, as defined in RCW 70A.305.020, that will be stored, handled or generated within the facility; the range of potential release volumes requiring cleanup in the event of failures of technological or safety catchment features; and whether such releases have the potential to contaminate groundwater or surface waters on or adjacent to the site;~~

~~(b) the range of cleanup activities that would be required to address such hazardous substances;~~

~~(c) detailed estimates of the cost to implement the plan, including conducting cleanup and facility closure, based on the cost of hiring a third party to conduct all activities. All cost estimates must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property; and~~

~~(d) methods for estimating closure costs.~~

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~~(4)(a) Financial responsibility shall be provided for the duration of facility operations, to be verified in the periodic review of the facilities required by subsection B.29.d. of this section. Financial responsibility required by this subsection B.29.c. may be established by any one of, or a combination of, the following methods acceptable to the department:~~

~~i. evidence of insurance;~~

~~ii. surety bonds issued by a bonding company authorized to do business in the United States; and~~

~~iii. other evidence of financial responsibility deemed acceptable by the department.~~

~~(b) Self-bonding, as defined by 30 C.F.R. Sec. 800.5, shall not be an accepted method of providing financial responsibility.~~

~~(5) Where enforcement of this subsection B.29.c. would conflict with chapter 36.32 RCW, the director may request the applicant to sign an agreement to complete retention of required financial responsibility consistent with K.C.C. 27A.30.060, in an amount equivalent to that indicated by the study of the damages, prior to the issuance of a clearing and grading permit~~)) meeting the requirements of K.C.C. chapter 21A.XX (the new chapter created by section 16 of this ordinance).

d. Non-hydroelectric generation facilities shall be subject to a periodic review meeting the same standards given in K.C.C. 21A.22.050. The financial responsibility required by subsection B.29.c. of this section shall be reviewed as part of the periodic review.

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30. Battery energy storage systems, except those defined as an accessory use under K.C.C. 21A.06.015, 21A.06.020, or 21A.06.025, are subject to the applicable permit requirements of subsection A. of this section and the following conditions:

a. A minimum separation of ten feet shall be maintained between rooms or enclosures containing battery energy storage systems and landscaping or other vegetation;

b. As part of building permit application submittal, battery energy storage systems shall demonstrate financial responsibility for public liability and environmental risks in accordance with K.C.C. chapter 21A.XX (the new chapter created by section 16 of this ordinance) if the total system capacity is more than two megawatts and all three of the following apply:

(1) the battery technology requires thermal runaway compliance under WAC 51-54A-1207.6;

(2) any individual room, cabinet, container, or other enclosure containing the system has an energy rating greater than two megawatt-hours, or any two enclosures are less than ten feet apart; and

(3) the system does not qualify as a remote installation under IFC 1207.8.1.;

c. As part of building permit application submittal, battery energy storage systems with a total system capacity more than two megawatts shall demonstrate financial responsibility for decommissioning in accordance with K.C.C. chapter 21A.XX (the new chapter created by section 16 of this ordinance);

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d. If financial responsibility is required by subsection B.30.b. or c. of this section, the applicant shall submit verification of financial responsibility to the department every five years, beginning five years from the date of permit issuance;

e. The findings and recommendations of studies, analyses, and testing required by K.C.C. Title 17, WAC 51-54A-1207, and the International Fire Code, should be incorporated into the permit conditions for the facility; and

f. As part of application submittal, the applicant shall submit verification that preliminary fire safety and evacuation plans have been shared with the local fire protection district. The final plans shall be shared with the local fire protection district before final inspection approval.

31.a. For all search and rescue facilities:

(1) the minimum lot size is four and one half acres;

(2) structures and parking areas for search and rescue facilities shall maintain a minimum distance of seventy-five feet from interior lot lines that adjoin rural area and residential zones, unless located in a building designated as historic resource under K.C.C. chapter 20.62;

(3) use of the search and rescue facility is limited to activities directly relating to the search and rescue organization, except that the facility may be used by law enforcement and other public emergency responders for training and operations related to search and rescue activities; and

(4) the applicant must demonstrate the absence of existing search and rescue facilities that are adequate to conduct search and rescue operations in the rural area.

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b. A special use permit is required when helicopter fueling, maintenance, or storage is proposed.

SECTION 11. Ordinance 10870, Section 354, as amended, and K.C.C. 21A.12.170 are each hereby amended as follows:

((~~Provided that~~)) If the required setbacks from regional utility corridors of K.C.C. 21A.12.140, the adjoining half-street or designated arterial setbacks of K.C.C. 21A.12.160, and the sight distance requirements of K.C.C. 21A.12.210 are maintained, structures may extend into or be located in required setbacks, including setbacks as required by K.C.C. 21A.12.220.((~~B~~)) C., as follows:

A. Fireplace structures, bay or garden windows, enclosed stair landings, closets, or similar structures may project into any setback, provided such projections are:

1. Limited to two per facade;

2. Not wider than ten feet; and

3. Not more than twenty-four inches into an interior setback or thirty inches into a street setback;

B. Uncovered porches and decks that exceed eighteen inches above the finished grade may project:

1. Eighteen inches into interior setbacks; and

2. Five feet into the street setback;

C. Uncovered porches and decks not exceeding eighteen inches above the finished grade may project to the property line;

D. Eaves may not project more than:

1. Eighteen inches into an interior setback;

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2. Twenty-four inches into a street setback; or

3. Eighteen inches across a lot line in a zero-lot-line development;

E. Fences with a height of six feet or less may project into or be located in any setback;

F. Rockeries, retaining walls, and curbs may project into or be located in any setback. Except for structures that cross the setback perpendicularly to property lines or that abut a critical area, these structures:

1. Shall not exceed a height of six feet in the R-1 through R-18, UR, RA, and resource zones;

2. Shall not exceed a height of eight feet in the R-24 and R-48 zones; and

3. Shall not exceed the building height for the zone in commercial/industrial zones, measured in accordance with the standards established in the King County Building Code, Title 16;

G. Fences located on top of rockeries, retaining walls, or berms are subject to the requirements of K.C.C. 21A.14.220;

H. Telephone, power, light, and flag poles;

I. The following may project into or be located within a setback, but may only project into or be located within a five foot interior setback area if an agreement documenting consent between the owners of record of the abutting properties is recorded with the records and licensing services division prior to the installment or construction of the structure:

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1. Sprinkler systems, electrical and cellular equipment cabinets, and other similar utility boxes and vaults, not to include equipment associated with a battery energy storage system;

2. security system access controls;

3. Structures, except for buildings, associated with trails and on-site recreation spaces and play areas required in K.C.C.21A.14.180 and K.C.C. 21A.14.190 such as benches, picnic tables, and drinking fountains; and

4. Surface water management facilities as required by K.C.C. 9.04;

J. Freestanding air conditioners and heat pumps may project into or be located within a setback abutting a residential property, but may only be located closer than five feet of an abutting residential property if an agreement documenting consent between the owners of record of the abutting properties is recorded with the records and licensing services division prior to permit issuance.

K. Mailboxes and newspaper boxes may project into or be located within street setbacks;

L. Fire hydrants and associated appendages;

M. Metro bus shelters may be located within street setbacks;

N. Unless otherwise allowed in K.C.C. 21A.20.080, free standing and monument signs four feet or less in height, with a maximum sign area of twenty square feet may project into or be located within street setbacks;

O. On a parcel in the RA zone, in the interior setback that adjoins a property zoned NB or CB, structures housing refrigeration equipment that extends no more than ten feet into the setback and is no more than sixty feet in length; ((~~and~~))

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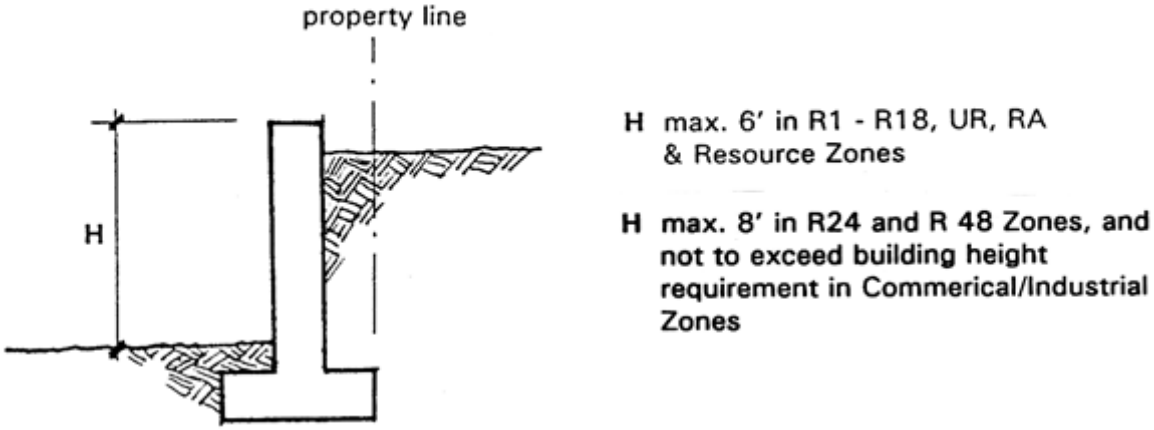
P. Stormwater conveyance and control facilities, both above and below ground, provided such projections are:

1. Consistent with setback, easement, and access requirements specified in the Surface Water Design Manual; or

2. In the absence of said specifications, not within five feet of the property line; and

Q. Equipment associated with a battery energy storage system defined as an accessory use under K.C.C. 21A.06.015, 21A.06.020, or 21A.06.025 may be located within a street setback, but only when used solely to supply electricity for electric-vehicle-charging infrastructure also within the setback or within the adjacent right-of-way.

RETAINING WALL IN SETBACK



SECTION 12. Ordinance 10870, Section 359, as amended, and K.C.C. 21A.12.220 are each hereby amended as follows:

A. The requirements of this section apply to all nonresidential uses located in the RA, UR, or R zones, except:

1. ((~~Except for u~~))Utility facilities((~~,~~));

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2. ((~~u~~))Uses listed in K.C.C. 21A.08.100, except that the standards in this section shall apply to battery energy storage systems not defined as accessory uses under K.C.C. 21A.06.015, 21A.06.020, or 21A.06.025; and

3. ((~~n~~))Nonresidential uses regulated by 21A.12.230((~~, all nonresidential uses located in the RA, UR, or R zones shall be subject to the following requirements:~~)).

((~~A.~~)) B. Impervious surface coverage shall not exceed:

1. Forty percent of the site in the RA zone.

2. Seventy percent of the site in the UR and the R-1 through R-8 zones.

3. Eighty percent of the site in the R-12 through R-48 zones.

((~~B.~~)) C. Buildings and structures, except fences and wire or mesh backstops, shall not be closer than 30 feet to any property line, except as provided in subsection ((~~C~~)) D.

((~~C.~~)) D. Single detached dwelling allowed as accessory to a church or school shall conform to the setback requirements of the zone.

((~~D.~~)) E. Parking areas are permitted within the required setback area from property lines, ((~~provided~~)) but only if such parking areas are located outside of the required landscape area.

((~~E.~~)) F. Sites shall abut or be accessible from at least one public street functioning at a level consistent with King County Road Design Standards. New high school sites shall abut or be accessible from a public street functioning as an arterial per the King County Design Standards.

((~~F.~~)) G. The base height shall conform to the zone in which the use is located.

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((~~G.~~)) H. Building illumination and lighted signs shall be designed so that no direct rays of light are projected into neighboring residences or onto any street right-of-way.

SECTION 13. Ordinance 10870, Section 388, as amended, and K.C.C. 21A.16.030 are each hereby amended as follows:

To facilitate the application of this chapter, the land uses of K.C.C. chapter 21A.08 have been grouped in the following manner:

A. Residential development refers to those uses listed in K.C.C. 21A.08.030, except those uses listed under Accessory uses, and:

1. Attached/group residences refers to:

a. townhouses, except as provided in subsection A.2.a. of this section;

b. apartments and detached dwelling units developed on common property at a density of twelve or more units per acre;

c. senior citizen assisted housing;

d. temporary lodging;

e. group residences other than Type I community residential facilities;

f. mobile home parks; and

2. Single-family development refers to:

a. residential subdivisions and short subdivisions, including attached and detached dwelling units on individually platted or short platted lots;

b. any detached dwelling units located on a lot including cottage housing units; and

c. Type I community residential facilities;

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B. Commercial development refers to those uses in:

1. K.C.C. 21A.08.040 as amusement/entertainment uses, except golf facilities;

2. K.C.C. 21A.08.050 except recycling centers, health and educational services, daycare I, churches, synagogues and temples, and miscellaneous repair as allowed in the A and RA zones; and

3. K.C.C. 21A.08.070, except forest product sales and agricultural product sales as allowed in the A, F, and RA zones and building, hardware, and garden materials as allowed in the A zones;

C. Industrial development refers to those uses listed in:

1. K.C.C. 21A.08.050 as recycling center;

2. K.C.C. 21A.08.060, except government services and farm product warehousing, refrigeration, and storage as allowed in the A zones;

3. K.C.C. 21A.08.080, except food and kindred products as allowed in the A and F zones; and

4. K.C.C. 21A.08.090 as mineral extraction and processing;

D. Institutional development refers to those uses listed in:

1. K.C.C. 21A.08.040 as cultural uses, except arboretums;

2. K.C.C. 21A.08.050 as churches, synagogues, and temples, health services, and education services except specialized instruction schools permitted as an accessory use;

3. K.C.C. 21A.08.060 as government services; and

4. Search and rescue facilities((.));

E. Utility development refers to those uses listed in:

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1. K.C.C. 21A.08.060 as utility facilities; and

2. K.C.C. 21A.08.100 as battery energy storage systems, except those defined as accessory uses under K.C.C. 21A.06.015, 21A.06.020, or 21A.06.025; and

F. Uses in K.C.C. chapter 21A.08 that are not listed in subsections A. through E. of this section shall not be subject to landscaping and tree retention requirements except as specified in any applicable review of a conditional use or special use permits, or reviews conducted in accordance with K.C.C. 21A.42.300.

SECTION 14. Ordinance 10870, Section 390, as amended, and K.C.C. 21A.16.050 are each hereby amended as follows:

The average width of perimeter landscaping along street frontages shall be provided as follows:

A. Twenty feet of Type II landscaping shall be provided for an institutional use, excluding playgrounds and playfields;

B. Ten feet of Type II landscaping shall be provided for an industrial development;

C. Ten feet of Type II landscaping shall be provided for an above-ground utility ((~~facilities~~)) development, excluding distribution and transmission corridors, located outside a public right-of-way;

D. Ten feet of Type III landscaping shall be provided for a commercial or attached/group residence development; and

E. For single family subdivisions and short subdivisions in the urban growth area:

1. Trees shall be planted at the rate of one tree for every forty feet of frontage along all public streets;

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2. The trees shall be:

a. Located within the street right-of-way if permitted by the custodial state or local agency;

b. No more than twenty feet from the street right-of-way line if located within a lot;

c. Maintained by the adjacent landowner unless part of a county maintenance program; and

d. A species approved by the county if located within the street right-of way and compatible with overhead utility lines.

3. The trees may be spaced at irregular intervals to accommodate sight distance requirements for driveways and intersections.

SECTION 15. Ordinance 10870, Section 391, as amended, and K.C.C. 21A.16.060 are each hereby amended as follows:

The average width of perimeter landscaping along interior lot lines shall be provided as follows:

A. Twenty feet of Type I landscaping shall be included in a commercial or industrial development along any portion adjacent to a residential development;

B. Five feet of Type II landscaping shall be included in an attached/group residence development, except that along portions of the development adjacent to property developed with single detached residences or vacant property that is zoned RA, UR or R(1-8), the requirement shall be ten feet of Type II landscaping;

C. Ten feet of Type II landscaping shall be included in an industrial development along any portion adjacent to a commercial or institutional development; and

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D. Ten feet of Type II landscaping shall be included in:

1. ((a))An institutional use, excluding ((of)) playgrounds and playfields((,)); or

2. ((a))An above-ground utility ((facility)) development, excluding distribution or transmission corridors, when located outside a public right-of-way.

NEW SECTION. SECTION 16. Section 17 of this ordinance should constitute a new chapter in K.C.C. Title 21A.

NEW SECTION. SECTION 17. When required by K.C.C. chapter 21A.08, uses shall demonstrate financial responsibility as follows:

A. Only for fossil fuel facilities and nonhydroelectric generation facilities, the applicant shall demonstrate financial responsibility in an amount necessary to compensate for the maximum damages that might occur from an explosion resulting from a worst-case release, as defined in 40 C.F.R. Sec. 68.3, of flammable gases and flammable liquids. The amount of financial responsibility shall be determined by the director based on a study of the maximum potential damages. The study shall:

1. Incorporate the volume of oils, gases, refrigerants, and other flammable or explosive chemicals stored, used, or generated within the facility;

2. Consider such matters as:

a. the frequency of facility operations;

b. facility layout and vegetation that could cause flammable vapor accumulation;

c. the damages that could result from the explosion to public and private structures onsite and offsite;

d. public infrastructure and environmental resources and functions; and

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e. The potential loss of life and injury to persons onsite and to members of the public;

3. Include modeling and disclosure of a nil or very low wind condition vapor cloud explosion scenario;

4. Be prepared by a person accredited in vapor cloud explosion analysis, or an equally qualified individual as authorized by the director, at the applicant's expense; and

5. Undergo third-party validation by a qualified entity to be hired upon mutual agreement of the applicant and the department, at the applicant's expense;

B. For battery energy storage systems only, the applicant shall demonstrate financial responsibility for public liability and environmental risks, in an amount of one million dollars, conditioned upon or responsive to the applicant's payment of damages to persons and property, up to one million dollars, resulting from or caused by a thermal event at a battery energy storage system. Nothing in this subsection shall be construed to limit an applicant from voluntarily obtaining financial responsibility for public liability and environmental risks in excess of one million dollars.

C. For fossil fuel facilities and nonhydroelectric generation facilities only, the applicant shall demonstrate financial responsibility in an amount necessary to compensate for facility decommissioning. The amount of financial responsibility shall be determined by the director based on a decommissioning plan for the closure of the facility. The plan shall include, but need not be limited to, the following:

1. Listing of the hazardous substances, as defined in RCW 70A.305.020, that will be stored, handled, or generated within the facility; the range of potential release volumes requiring cleanup in the event of failures of technological or safety catchment

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features; and whether such releases have the potential to contaminate groundwater or surface waters on or adjacent to the site;

2. The range of cleanup activities that would be required to address such hazardous substances;

3. Detailed estimates of the cost to implement the plan, including conducting cleanup and facility closure, based on the cost of hiring a third party to conduct all activities. All cost estimates must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property; and

4. Methods for estimating closure costs;

D. For battery energy storage systems only, the applicant shall demonstrate financial responsibility in an amount necessary to compensate for facility decommissioning. The required financial responsibility for decommissioning, which may be packaged with, but shall be additional to, any public liability financial responsibility required by subsection B. of this section, shall be in an amount to carry out all contingencies of the decommissioning plan required by WAC 51-54A-1207, including:

1. The range of cleanup activities that would be required for site decommissioning;

2. Detailed estimates of the cost to implement the plan, including conducting facility closure, based on the cost of hiring a third party to conduct all activities. All cost estimates must be in current dollars and may not include a net present value adjustment or offsets for salvage value of wastes or other property; and

3. Methods for estimating closure costs;

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E. Financial responsibility shall be provided for the duration of facility operations, to be periodically reviewed, if required, in the manner prescribed for the use in K.C.C. chapter 21A.08;

F.1. Financial responsibility required by this chapter may be established by any one of, or a combination of, the following methods:

a. evidence of insurance;

b. surety bonds issued by a bonding company authorized to do business in the United States;

c. letter of credit; or

d. other evidence of financial responsibility deemed acceptable by the department.

2. Self-bonding, as defined in 30 C.F.R. Sec. 800.5, shall not be an accepted method of providing financial responsibility; and

G. Where enforcement of this chapter would conflict with chapter 36.32 RCW, the director may request the applicant to sign an agreement to complete retention of required financial responsibility consistent with K.C.C. 27A.30.060, in an amount equivalent to that required by this chapter, before the issuance of a clearing and grading permit.

SECTION 18. Ordinance 12020, Section 17, as amended, and K.C.C. 27A.30.060 are each hereby amended as follows:

Consistent with chapter 36.32 RCW, King County shall not require any state agency or unit of local government to secure the performance of a permit requirement with a financial guarantee as a condition of issuing a permit or approval for a building

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construction project. The director, however, may request a state agency or unit of local government to sign an agreement to complete required improvements, or to complete retention of required financial responsibility consistent with K.C.C. ((~~21A.08.100~~)) chapter 21A.XX (the new chapter created by section 16 of this ordinance), and protect the county's rights and duty to remedy unsatisfactory performance.

SECTION 19.

A. The executive shall prepare a battery energy storage systems study report. The executive shall consult with representatives of the energy industry, emergency response community, renewable energy industry, labor, and state and local governments to assist in developing the report. The report shall include, but not be limited to:

1. If applications have been received or pre-application meetings held in the timeframe given in subsection B. of this section, information on each battery energy storage system that applied to the department of local services, permitting division, for permits or preapplication meetings after the effective date of this ordinance, including but not limited to:

a. whether the system was accessory or not, and if so, what type of use it was accessory to;

b. whether permits were issued or applied for;

c. in cases where a permit was not issued, any available information on barriers to permit issuance or application; and

d. in cases where a permit was issued:

(1) the total system capacity in megawatts;

(2) the total number of containers, cabinets, or rooms housing the system;

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(3) site characteristics, such as lot size, zoning, and any other pertinent information;

(4) whether the system required financial responsibility; and

(5) whether additional conditions were imposed under subsection 10.B.30.e. of this ordinance;

2. Information on any changes to standards relating to energy storage systems in the International Fire Code, as adopted by the state or county, since the effective date of this ordinance, and discussion of how those changes do or do not impact the requirements of this ordinance;

3. Information on changes to battery technology or safety systems that have occurred since the effective date of this ordinance, and how those changes do or do not impact the requirements of this ordinance;

4. An analysis of the impact and effectiveness of the financial responsibility requirements of this ordinance, and evaluation of alternatives for ensuring financial responsibility if warranted;

5. An analysis of the county's progress towards its Strategic Climate Action Plan targets for battery energy storage capacity;

6. An analysis of gaps that exist in the existing county and state regulatory structure for battery energy storage systems; and

7. Any recommendations for changes to the county's regulations for battery energy storage systems, based on the information gained during the development of the report.

B.1. No later than one year from the date that the first battery energy storage

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system permitted under this ordinance receives final inspection approval, or three years from the date this ordinance is enacted, whichever comes first, the executive shall electronically file the report with the clerk of the council, who shall retain an electronic copy and provide an electronic copy to all councilmembers, the council chief of staff, and the lead staff for the local services and land use committee or its successor. If legislative action is necessary to implement the recommendations of the report, a proposed ordinance shall be transmitted with the report. If legislative action is not necessary to implement the recommendations of the report, a proposed motion acknowledging receipt of the report shall be transmitted with the report.

SECTION 20. **Severability.** If any provision of this ordinance or its application

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to any person or circumstance is held invalid, the remainder of the ordinance or the application of the provision to other persons or circumstances is not affected.

Ordinance 19824 was introduced on 7/25/2023 and passed as amended by the Metropolitan King County Council on 9/24/2024, by the following vote:

Yes: 8 - Balducci, Barón, Dembowski, Mosqueda, Perry, Upthegrove, von Reichbauer and Zahilay
No: 1 - Dunn

KING COUNTY COUNCIL
KING COUNTY, WASHINGTON

Signed by:
E76CE01F07B14EF...
Dave Upthegrove, Chair

ATTEST:

DocuSigned by:
Melani Hay
8DE1BB375AD3422...
Melani Hay, Clerk of the Council

APPROVED this _____ day of 10/1/2024, _____.

Signed by:
4FBCAB8196AE4C6...
Dow Constantine, County Executive

Attachments: None

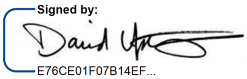
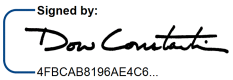
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Signing Complete	Security Checked	10/1/2024 3:10:00 PM
Completed	Security Checked	10/1/2024 3:10:00 PM

Payment Events	Status	Timestamps

Electronic Record and Signature Disclosure

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If you decide to receive notices and disclosures from us electronically, you may at any time change your mind and tell us that thereafter you want to receive required notices and disclosures only in paper format. How you must inform us of your decision to receive future notices and disclosure in paper format and withdraw your consent to receive notices and disclosures electronically is described below.

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If you elect to receive required notices and disclosures only in paper format, it will slow the speed at which we can complete certain steps in transactions with you and delivering services to you because we will need first to send the required notices or disclosures to you in paper format, and then wait until we receive back from you your acknowledgment of your receipt of such paper notices or disclosures. Further, you will no longer be able to use the DocuSign system to receive required notices and consents electronically from us or to sign electronically documents from us.

All notices and disclosures will be sent to you electronically

Unless you tell us otherwise in accordance with the procedures described herein, we will provide electronically to you through the DocuSign system all required notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you during the course of our relationship with you. To reduce the chance of you inadvertently not receiving any notice or disclosure, we prefer to provide all of the required notices and disclosures to you by the same method and to the same address that you have given us. Thus, you can receive all the disclosures and notices electronically or in paper format through the paper mail delivery system. If you do not agree with this process, please let us know as described below. Please also see the paragraph immediately above that describes the consequences of your electing not to receive delivery of the notices and disclosures electronically from us.

How to contact King County-Department of 02:

You may contact us to let us know of your changes as to how we may contact you electronically, to request paper copies of certain information from us, and to withdraw your prior consent to receive notices and disclosures electronically as follows:
To contact us by email send messages to: cipriano.dacanay@kingcounty.gov

To advise King County-Department of 02 of your new email address

To let us know of a change in your email address where we should send notices and disclosures electronically to you, you must send an email message to us at cipriano.dacanay@kingcounty.gov and in the body of such request you must state: your previous email address, your new email address. We do not require any other information from you to change your email address.

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To request delivery from us of paper copies of the notices and disclosures previously provided by us to you electronically, you must send us an email to cipriano.dacanay@kingcounty.gov and in the body of such request you must state your email address, full name, mailing address, and telephone number. We will bill you for any fees at that time, if any.

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To inform us that you no longer wish to receive future notices and disclosures in electronic format you may:

i. decline to sign a document from within your signing session, and on the subsequent page, select the check-box indicating you wish to withdraw your consent, or you may;

ii. send us an email to cipriano.dacanay@kingcounty.gov and in the body of such request you must state your email, full name, mailing address, and telephone number. We do not need any other information from you to withdraw consent.. The consequences of your withdrawing consent for online documents will be that transactions may take a longer time to process..

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The minimum system requirements for using the DocuSign system may change over time. The current system requirements are found here: https://support.docusign.com/guides/signer-guide-signing-system-requirements.

Acknowledging your access and consent to receive and sign documents electronically

To confirm to us that you can access this information electronically, which will be similar to other electronic notices and disclosures that we will provide to you, please confirm that you have read this ERSD, and (i) that you are able to print on paper or electronically save this ERSD for your future reference and access; or (ii) that you are able to email this ERSD to an email address where you will be able to print on paper or save it for your future reference and access. Further, if you consent to receiving notices and disclosures exclusively in electronic format as described herein, then select the check-box next to 'I agree to use electronic records and signatures' before clicking 'CONTINUE' within the DocuSign system.

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- You can access and read this Electronic Record and Signature Disclosure; and
- You can print on paper this Electronic Record and Signature Disclosure, or save or send this Electronic Record and Disclosure to a location where you can print it, for future reference and access; and
- Until or unless you notify King County-Department of 02 as described above, you consent to receive exclusively through electronic means all notices, disclosures, authorizations, acknowledgements, and other documents that are required to be provided or made available to you by King County-Department of 02 during the course of your relationship with King County-Department of 02.

FINAL BILL REPORT
E2SSB 5116

C 288 L 19
Synopsis as Enacted

Brief Description: Supporting Washington's clean energy economy and transitioning to a clean, affordable, and reliable energy future.

Sponsors: Senate Committee on Ways & Means (originally sponsored by Senators Carlyle, Palumbo, McCoy, Pedersen, Wellman, Das, Rolfes, Frockt, Wilson, C., Kuderer, Nguyen, Keiser, Liias, Hunt, Saldaña, Darneille and Billig; by request of Governor Inslee).

Senate Committee on Environment, Energy & Technology
Senate Committee on Ways & Means
House Committee on Environment & Energy
House Committee on Finance
House Committee on Appropriations

Background: Energy Independence Act. Initiative 937, also called the Energy Independence Act (EIA), requires electric utilities with 25,000 or more customers to meet targets for energy conservation and for using eligible renewable resources.

Greenhouse Gas Emissions Performance Standard for Electric Generation Plants. Electric utilities may not enter into a long-term financial commitment for baseload electric generation on or after July 1, 2008, unless the generating plant's emissions are the lower of:

- 1100 pounds of greenhouse gas (GHG) per megawatt-hour (MWh); or
- the average available GHG output as updated by the Department of Commerce (Commerce), which is currently set at 970 pounds per MWh.

Baseload electric generation means electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent. Long-term financial commitment means:

- either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or
- a new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

Greenhouse Gas Emissions Performance Standard and Coal Transition Power. In 2011 the Legislature established a schedule for applying the Greenhouse Gas Emissions Performance Standard (EPS) to the Centralia coal-fired electric generation facility. In addition, the EPS

This analysis was prepared by non-partisan legislative staff for the use of legislative members in their deliberations. This analysis is not a part of the legislation nor does it constitute a statement of legislative intent.

was amended to allow long-term contracts for Centralia's generated electricity, called coal transition power. A process was created to allow electric investor-owned utilities (IOUs) to petition the Utilities and Transportation Commission (UTC) for approval of a power purchase agreement for coal transition power.

Integrated Resource Plans. All investor-owned and consumer-owned electric utilities in the state with more than 25,000 customers must develop integrated resource plans (IRPs). All other electric utilities in the state, including those that essentially receive all their power from the Bonneville Power Administration (BPA), must file either an IRP or a less-detailed resource plan (RP).

IRPs and RPs must be updated every two years. IOUs must submit their plans to the UTC. Consumer-owned utilities (COUs) must file a copy of their plans with Commerce every two years.

Summary: Coal Phase-Out Standard. By December 31, 2025, all electric utilities must eliminate coal-fired resources from their allocation of electricity. The cost of delivering power does not include the costs associated with decommissioning and remediation of the facilities.

For IOUs, the UTC is required to accelerate depreciation for any coal-fired resource owned by an IOU and is allowed to accelerate depreciation for any qualified transmission line to no later than December 31, 2025. The UTC must allow in rates prudently incurred undepreciated investments in a fossil-fuel generating resource that has been retired from service under specific conditions.

For the purposes of this standard, "coal-fired resource" does not include:

- an electric generating facility that is subject to an obligation to meet the state's Greenhouse Gas Emissions Performance Standard; or
- an electric generation facility that is included as part of certain limited duration wholesale power purchases.

Greenhouse Gas Neutral Standard. By January 1, 2030, each electric utility must make all retail sales of electricity to Washington customers GHG neutral. To achieve compliance with this standard, an electric utility must:

- pursue all cost-effective, reliable, and feasible conservation and efficiency resources and demand response resources to reduce or manage electric retail load; and
- use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the utility's average annual retail electric load.

An electric utility must achieve compliance with the GHG neutral standard for multiyear compliance periods beginning January 1, 2030, through December 31, 2044.

All renewable resources used to meet the compliance obligation must be verified using renewable energy credits (RECs), and must be tracked and retired in the tracking system selected by Commerce. Non-emitting generation resources used to meet the obligation must be generated during the compliance period and must be verified by documentation that the utility owns the nonpower attributes of the electricity.

An electric utility may satisfy up to 20 percent of the standard with an alternative compliance option through December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment;
- purchasing unbundled RECs;
- investing in energy transformation projects; or
- using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992 and is in compliance with federal and state air quality standards.

Energy transformation projects must meet criteria and quality standards developed by the Department of Ecology (Ecology), in consultation with Commerce and the UTC. Criteria for emissions reductions must be met.

Energy transformation projects must be associated with the consumption of energy in Washington. Any compliance obligation fulfilled through investment in such a project is only eligible for use by the entity that makes the investment: an electric utility; a preference customer of BPA; or a member of a joint operating agency under current law.

Clean Energy Standard. By January 1, 2045, each electric utility must meet 100 percent of its retail electric load to Washington customers using non-emitting electric generation and electricity from renewable resources. UTC, Commerce, the Energy Facility Site Evaluation Council, Ecology, and all other state agencies must incorporate this standard into all relevant planning and use all statutory programs to achieve the standard.

In planning to meet projected demand, an electric utility must, consistent with the requirements of the Energy Independence Act, pursue all cost-effective, reliable, and feasible conservation efficiency resources, and demand response. In making new investments, an electric utility must, and to the maximum extent feasible, achieve targets at the lowest reasonable cost; consider acquisition of surplus renewable resources, and in the acquisition of new resources rely on renewable resources and energy storage.

Hydroelectric Generation. In complying with the GHG neutral standard and clean energy standard, an electric utility may not use hydroelectric generation that requires new diversions, impoundments, or bypass reaches, or expansion of existing reservoirs, unless otherwise required for the operation of a pumped storage facility. An electric utility may make efficiency or other improvements to its existing facilities and may install hydroelectric generation in pipes, culverts, irrigation canals, and other manmade waterways.

Nothing in the GHG neutral or clean energy standards prohibits an electric utility from purchasing or exchanging power from BPA.

Market Customers. Customers who become market customers after the effective date of this act must comply with the obligations of the GHG neutral and clean energy standards. A market customer that purchases electricity exclusively from carbon-free resources and eligible renewable resources, as defined under the EIA as of January 1, 2019, pursuant to a special contract with an IOU, is subject to the requirements of that contract.

Clean Energy Implementation Plans and Incremental Cost Caps. By January 1, 2022, and every four years thereafter, each electric utility must develop a four-year Clean Energy Implementation Plan (CEIP) for the GHG neutral and clean energy standards and establish interim targets for meeting the standards. The CEIP must identify specific actions to be taken by the electric utility over the next four years, consistent with the utility's long-range resource plan and resource adequacy requirements.

An IOU must be considered in compliance with the GHG neutral and clean energy standards if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the utility's interim targets equals a 2 percent increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year.

A COU must be considered in compliance with the GHG neutral and clean energy standards if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the utility's interim targets meets, but does not exceed, a 2 percent increase of the COU's retail revenue requirement above the previous year.

Early Action Compliance Credits. A multistate electric utility with fewer than 250,000 customers in Washington may apply the total amount of MWhs of coal-fired resources eliminated from the utility's allocation of electricity before December 31, 2025, as an equivalent amount of MWhs of nonemitting electric generation or electricity from renewable resources required to comply with the GHG neutral standard. The utility must demonstrate that for every MWh of early action credit there is a real, permanent reduction in greenhouse gas emissions in the Western Interconnection directly associated with that credit. A multistate electric utility must request to use early compliance credits in its CEIP and may not use the early action compliance credits beyond 2035. The UTC must establish conditions for use of early action compliance credits.

Administrative Penalty. An electric utility that fails to comply with the coal-elimination or carbon neutral standards must pay a $100 administrative penalty, times the following multipliers, for each MWh of emitting or unspecified electric generation used to meet an electric utility's retail electric load:

- 1.5 for coal-fired resources;
- 0.84 for gas-fired peaking power plants; and
- 0.60 for gas-fired combined-cycle power plants.

The penalty is adjusted for inflation, beginning in 2027. Beginning in 2040, the UTC may increase the penalty for IOUs to accelerate compliance.

An electric utility may elect to pay an amount equal to the administrative penalty as an alternative compliance option.

The UTC, for an IOU, may relieve the utility of its penalty, or the governing body of a COU may authorize a temporary exemption from the GHG neutral standard if it finds that a utility's compliance is likely to result in conflicts with or compromises to its obligation to comply with NERC reliability standards, violate prudent utility practice for assuring resource

adequacy, compromise the power quality or integrity of its system, or due to factors reasonably outside the utility's control.

Upon request by the governing body of a consumer-owned utility, a consumer-owned utility must be relieved of its administrative penalty obligation if the auditor issues a finding that the governing body has properly issued a temporary exemption for a period of time not to exceed six months, and the governing body has submitted to Commerce a plan to take specific actions to achieve full compliance.

The attorney general may bring a civil action for an appropriate civil remedy including, but not limited to, injunctive relief, penalties, costs, and attorneys' fees, to enforce compliance with the coal phase-out and GHG neutral standards.

Additionally, the Governor may waive a penalty by declaring an energy emergency under current law if Commerce's report demonstrates adverse system reliability impacts due to implementation of the coal phase-out or GHG neutral standards.

Monies collected must be deposited into existing low-income weatherization and structural rehabilitation assistance accounts. The standard is enforced by the UTC for IOUs and the state auditor's office for COUs.

The fair market value compensation for an asset that is condemned by a municipal electric utility, public utility district, or irrigation district must include, but not be limited to, a replacement value approach, if it is either demonstrated in an electric utility's Clean Energy Action Plan or CEIP to be used or acquired after the effective date of this act to meet the requirements of the GHG neutral standard or clean energy standard, or an asset that generates electricity from renewable resources or nonemitting electric generation.

Additionally, the electric utility may seek, and the court may award, damages attributable to the severance, separation, replacement, or relocation of utility assets. The trier of fact may also consider other damages that it finds just and equitable.

An entity that establishes or extends service to the premises of a customer who is being served by an electric utility or was served by an electric utility prior to the effective date of this act must serve those premises in a manner that complies with the requirements of this act and with the EIA, if applicable.

Reporting Requirements. By January 1, 2024, and every four years thereafter, Commerce must report to the Legislature a review of the three standards focused on technologies, forecasts, existing transmission, environmental and public safety, affordability, and reliability. The report must include an evaluation of impacts or costs and benefits on system reliability and utilities; an evaluation identifying anticipated financial costs and benefits to electric utilities; an evaluation of new or emerging technologies that could be considered a renewable resources; and an assessment of the impacts on middle-income families, small businesses, and manufacturers in Washington.

Rulemaking Authority. By January 1, 2021, UTC for IOUs and Commerce for COUs may adopt rules. Nothing restricts rate-making authority of the governing bodies of COUs unless

otherwise provided by law. UTC and Commerce are encouraged to coordinate and consult with other agencies in developing rules.

Commerce must adopt rules establishing reporting requirements for electric utilities to demonstrate compliance with the coal phase-out, GHG neutral, and clean energy standards.

Ecology must adopt rules, in consultation with UTC and Commerce, to establish requirements for energy transformation project investments.

The requirements of this act do not replace or modify the requirements of the EIA.

Energy Resource Planning. For electric utilities required to develop an IRP, the IRP must include the following:

- an assessment and 10-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;
- a determination of resource adequacy metrics for the resource plan consistent with the forecasts;
- 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;
- an assessment, informed by the Department of Health's Cumulative Impact Analysis, of energy and nonenergy benefits and reductions of burdens to vulnerable communities and highly impacted communities; and
- a 10-year clean energy action plan for implementing the coal phase-out standard, the GHG neutral standard, and the clean energy standard 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 IRP.

An electric utility must consider the social cost of GHG emissions when developing its IRP and clean energy action plan. An electric utility must incorporate the social cost of GHG emissions as a cost adder when evaluating and selecting conservation policies, programs, and targets and evaluating and selecting intermediate term and long-term resource options.

Integrated Resource Plans and Clean Energy Action Plans. An IOU must develop the following: (1) a 10-year clean energy action plan and strategy 4-year clean energy implementation plan identifying specific actions with long-ranging integrated resource planning and resource adequacy requirements, and proposing interim targets for implementing the coal phase out and carbon-neutral standards at the lowest reasonable cost; and (2) a 20-year clean energy transformation plan identifying the lowest reasonable cost pathways to meet the 100 percent clean standard. Specific requirements are set for the clean energy action plan and compliance strategy.

The cost of GHG emissions resulting from the generation of electricity is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5 percent discount rate published by the Interagency Working Group on Social Cost of GHGs of the United States government.

By December 31, 2020, and in every resource plan thereafter, an electric utility that is not required to develop an IPR must include in its Resource Plan how it plans to implement the GHG neutral and clean energy standards over a 10-year period.

Utilities and Transportation Commission Property Valuation and Authority. UTC's authority to determine the fair value of property for rate making purposes is amended to include the consideration of property acquired or constructed by or during the rate effective period, including the reasonable costs of construction work in progress, to the extent UTC finds that the inclusion is in the public interest and will yield fair, just, reasonable, and sufficient rates. UTC is authorized to approve changes to these rates for up to 48 months, and must establish a process to identify, review, and approve property that becomes used and useful after the rate effective date.

The UTC's authority to consider and implement performance and incentive-based regulation, multiyear rate plans, and other flexible regulatory mechanisms is clarified.

Deferral of Costs. An electric utility may apply to the UTC to defer for later consideration costs incurred in connection with the acquisition or development of resources identified in the utility's clean energy implementation plan. The deferral begins on the date the resource begins commercial operation or on the effective date of a power purchase agreement and continues for up to 24 months, unless a general rate case or other proceeding for the recovery of such costs ensues.

The costs that a utility may account for and defer for later consideration by the UTC include all operating and maintenance costs, depreciation, taxes, costs of capital associated with the applicable resources, or the execution of a power purchase agreement. Costs of capital include the utility's authorized return on equity for any resource acquired or development, or a rate of return no less than the authorized cost of debt and no greater than the authorized rate of return of the company for a power purchase agreement.

Low-income Assistance. Electric utilities must make funding available for low-income bill assistance by July 31, 2021. Beginning July 31, 2020, Commerce must collect and aggregate data estimating energy burden and energy assistance need and reported energy assistance need for each utility, and update the specified aggregated data biennially.

Electricity Market Work Group. Commerce and UTC must convene a stakeholder work group to examine the efficient and consistent integration of this act and transactions with carbon and electricity markets outside Washington and compatibility with a linked cap-and-trade program.

Commerce and UTC must adopt rules by June 30, 2022, defining requirements for retail electric load met with market purchases and the Western Energy Imbalance Market or other centralized markets, and to address the prohibition on double counting of nonpower attributes.

Energy Strategy Advisory Committee. Commerce must review the state energy strategy in order to align it with the purposes of this act and Ecology's recommended GHG emission reductions by December 31, 2020, and at least once every eight years thereafter, subject to

funding. A specified 26-member state energy advisory committee must be established for each review.

Energy and Climate Policy Advisory Committee. A policy advisory committee is created to develop recommendations to the Legislature to examine costs and benefits of energy-related policies and to conduct other energy-related studies as directed, to be reported by December 31, 2020, subject to funding. Membership includes Washington's four-year higher education institutions, the Pacific Northwest National Laboratory, and the Washington State Institute of Public Policy.

Cumulative Impact Analysis. By December 31, 2020, the Department of Health must conduct or adopt a cumulative impact analysis to designate the communities highly impacted by fossil fuel pollution and climate change in Washington. By December 31, 2021, Commerce and UTC must establish requirements for incorporating the cumulative impact analysis into the clean energy action plans and clean energy transformation plans.

Transmission Work Group. The Energy Facility Site Evaluation Council must convene an inter-agency transmission work group to look at the need for transmission and strategies for designating transmission corridors and improving coordination in siting transmission, and report findings to the Governor and Legislature by December 31, 2022.

Extending Sales & Use Tax Exemptions. The expiration date is extended from January 1, 2020, to December 31, 2030, for the sales and use tax exemptions for alternative energy machinery and equipment.

A purchaser, as well as the consumer, who have paid tax on machinery and equipment used to generate electricity consistent with the purposes of the act is entitled to an exemption of state and local taxes, in the form of a remittance of:

- 50 percent if the procurement and contract was from an organization owned by women, minorities, or veterans;
- 75 percent if workers on the project were compensated at prevailing wages determined by local collective bargaining; or
- 100 percent if the project is developed under a community workforce agreement or project labor agreement.

Allowances are provided for good faith efforts to meet one of the above requirements, given certain conditions.

Beginning January 1, 2020, through December 31, 2029, the purchaser of eligible machinery and equipment for solar energy systems greater than 100 kW but no more than 500 kW is entitled to an exemption, in the form of a remittance, in an amount equal to 50 percent of the state and local sales and use tax paid, if the Department of Labor and Industries (L&I) certifies that the project meets certain labor and procurement standards and the purchaser provides certain documentation.

Beginning July 1, 2019, through December 31, 2029, the purchaser of eligible machinery and equipment for solar energy systems smaller than 100 kW in size is entitled to an exemption

in an amount equal to 100 percent of the state and local sales and use tax paid if the purchaser meets certain requirements.

Community workforce agreements and project labor agreements are defined. L&I is responsible for administering the provisions of the labor standards used in this section of the bill and is directed to conduct emergency rule making, to be completed by December 1, 2019.

Energy Independence Act. Beginning January 1, 2020, a qualifying utility may use the following as eligible renewable resources to comply with the EIA:

- incremental electricity produced as a result of efficiency improvements to hydroelectric generation projects whose energy output is marketed by BPA, if the improvements are completed after March 31, 1999, and the additional generation does not result in new water diversions or impoundments; and
- the environmental attributes of incremental hydroelectricity, including RECs, allocated to IOUs pursuant to the residential exchange program as an eligible renewable resource to comply with the EIA.

Beginning January 1, 2030, a qualifying utility will be in compliance with the annual targets for eligible renewable resources under the EIA if the utility uses electricity from renewable resources, non-emitting electric generation, and RECs, in an amount equal to 100 percent of the utility's average annual retail electric load.

Votes on Final Passage:

Senate	28	19	
House	56	42	(House amended)
Senate	29	20	(Senate concurred)

Effective: May 7, 2019

FINAL BILL REPORT
E2SSB 5126

PARTIAL VETO
C 316 L 21
Synopsis as Enacted

Brief Description: Concerning the Washington climate commitment act.

Sponsors: Senate Committee on Ways & Means (originally sponsored by Senators Carlyle, Saldaña, Conway, Das, Frockt, Hunt, Liias, Nguyen, Pedersen, Salomon, Stanford and Wilson, C.; by request of Office of the Governor).

Senate Committee on Environment, Energy & Technology
Senate Committee on Ways & Means
House Committee on Environment & Energy
House Committee on Appropriations

Background: Cap and trade is a market-based, economy-wide approach to reduce pollution, which is comprised of two key components—a limit or cap on carbon emissions and tradable allowances. In the United States, nine states participate in the Regional Greenhouse Gas Initiative, a cap and trade program established in 2009. California began operating a cap and trade program in 2013, and it is linked with a program in Quebec, Canada. European countries have operated a cap and trade program since 2005.

Greenhouse Gasses. The United States Environmental Protection Agency (EPA) and state Department of Ecology (Ecology) identify carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride as greenhouse gasses (GHGs) as a result of their capacity to trap heat in the earth's atmosphere. According to the EPA, the global warming potential (GWP) of each GHG is a function of how much of the gas is concentrated in the atmosphere, how long the gas stays in the atmosphere, and how strongly the particular gas affects global atmospheric temperatures. Under state law, the GWP of a gas is measured in terms of the equivalence, over a 100-year timeframe, to the emission of an identical volume of carbon dioxide (carbon dioxide equivalent).

Current Federal and Washington Regulation of Greenhouse Gasses. Under the federal Clean Air Act, GHGs are regulated as an air pollutant and are subject to several air

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This analysis was prepared by non-partisan legislative staff for the use of legislative members in their deliberations. This analysis is not part of the legislation nor does it constitute a statement of legislative intent.

regulations administered by the EPA. These federal Clean Air Act regulations include a requirement that facilities and fuel suppliers whose associated annual emissions exceed 25,000 metric tons of carbon dioxide equivalent report their emissions to the EPA.

At the state level, GHGs are regulated by Ecology under the state Clean Air Act (CAA). Facilities, sources, and sites whose emissions exceed 10,000 metric tons of carbon dioxide equivalent each year are required to report their annual emissions to Ecology or to local air authorities that implement the state CAA. Liquid motor vehicle and aircraft fuel suppliers that supply fuel whose combustion would exceed that same 10,000 ton volumetric threshold must also report their annual emissions.

Apart from reporting and other regulations under the state and federal clean air acts, several other state laws and programs explicitly address GHG emissions.

In 2020, the Legislature updated statewide GHG emissions reduction limits (emissions limits) set in 2008 to: a 95 percent reduction below 1990 levels by 2050, with interim economy-wide emissions limits of 45 percent below 1990 levels by 2030 and 70 percent below 1990 levels by 2040. The state must achieve net zero emissions by 2050.

Ecology is responsible for monitoring and tracking the state's progress toward the emission limits.

Clean Energy Transformation Act. In 2019, the Legislature passed the Clean Energy Transformation Act (CETA), which requires Washington's electric utilities to meet 100 percent of their retail electric load using non-emitting and renewable resources by January 1, 2045. CETA requires electric utilities to eliminate coal-fired resources from their allocation of electricity by December 31, 2025, and make all retail sales of electricity GHG neutral by January 1, 2030. CETA also requires electric utilities to develop a clean energy implementation plan every four years, starting January 1, 2022, to establish interim targets for energy efficiency and renewable energy.

Environmental Justice Task Force Report. A proviso in the 2019-2021 biennial operating budget directed the Governor's Interagency Council on Health Disparities to convene and staff an Environmental Justice Task Force. The task force was directed to recommend strategies for incorporating environmental justice principles into future state agency actions across Washington. The task force report, published in fall 2020, includes:

- guidance for using the Washington Environmental Health Disparities Map to identify communities that are highly impacted by environmental justice issues with current demographic data;
- measurable goals for reducing environmental health disparities for each community in Washington State and ways in which state agencies may focus their work towards meeting those goals; and
- model policies that prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and

advancing a healthy environment for all residents.

Office of Equity. In 2020, the Legislature established the Office of Equity to promote access to equitable opportunities and resources that reduce disparities and improve outcomes statewide across state government. Duties of the office include facilitating state policy and systems change to promote equitable policies, practices, and outcomes.

Summary: Environmental Justice Review. Ecology must conduct an environmental justice review every two years, beginning in 2023, to ensure the cap and invest program achieves reductions in criteria pollutants as well as GHG emissions in overburdened communities highly impacted by air pollution. Ecology must deploy an air monitoring network in high priority overburdened communities to collect sufficient air quality data for the 2023 review and subsequent reviews.

Once the review determines the levels of criteria pollutants in an identified overburdened community , Ecology must:

- in consultation with local air pollution control authorities, establish air quality targets to achieve air quality consistent with whichever is more protective for human health:
    1. national ambient air quality standards established by EPA; or
    2. the air quality experienced in neighboring communities that are not identified as overburdened;
- identify the stationary and mobile sources that are the greatest contributors of those emissions that are either increasing or not decreasing;
- achieve the reduction targets through adoption of emission control strategies or other methods;
- adopt stricter air quality standards, emission standards, or emissions limitations on criteria pollutants; and
- after adoption of the stricter air quality standards, emission standards, or emissions limitations, issue an enforceable order on affected permittees or registered sources to comply with the stricter standards or limitations.

Ecology may not impose requirements on a permitted stationary source that are disproportionate to their contribution to air pollution compared to other permitted stationary sources and other sources of criteria pollutants in the overburdened community.

Environmental Justice Assessment. When allocating funds or administering grants funded by any of the program accounts, agencies must conduct an environmental justice assessment and establish a minimum of not less than 35 percent, and a goal of 40 percent, of total investments to provide direct and meaningful benefits to vulnerable populations within overburdened communities. Benefits may be achieved through reducing environmental burdens and cumulative risk from environmental burdens, supporting community-led projects, or meeting an identified community need.

An additional 10 percent minimum target is established for projects supported by tribal

resolution, with priority to projects directly administered or proposed by a tribe.

Environmental Justice Council. The Environmental Justice Council, established under E2SSB 5141, must provide recommendations to the Legislature, agencies, and the Governor on the development and implementation of the cap and invest program, and programs funded from the auction revenues.

Duties of the council include:

- providing recommendations to the Legislature, agencies, and the Governor in the development of the cap and invest program and investment plans and funding proposals from the Climate Investment Account;
- recommending environmental justice and environmental health goals for programs, activities, and projects funded from the account, and reviewing agency annual reports on outcomes and progress toward meeting goals; and
- providing a forum to analyze policies adopted under the comprehensive climate commitment program to determine if policies lead to improvements within overburdened communities.

Governance Structure. The Governor must establish a governance structure to implement the state's climate commitment to provide accountability for achieving the state's emission limits, establish a coordinated and strategic statewide approach to climate resilience, build an equitable and inclusive clean energy economy, and ensure the government provides clear policy and requirements, financial tools, and other mechanisms to support achieving those limits.

The governance structure for implementing the climate commitment must be holistic; address emissions reductions from all relevant sectors and sources; support an equitable transition for vulnerable populations and overburdened communities; build increasing climate resilience for at-risk communities and ecosystems through cross-sectoral coordination, planning and policies; and apply scientific and technical information. The governance structure must include the following elements:

- a strategic plan for aligning existing law, rules, policies, programs, and plans with the state's emissions limits to the full extent allowed;
- common state policies, standards, and procedures for addressing GHG emissions and climate resilience;
- a process for prioritizing and coordinating funding consistent with strategic needs for GHG reductions, equity and environmental justice, and climate resilience actions;
- an updated statewide strategy for addressing climate risks and improving resilience of communities and ecosystems;
- a comprehensive community engagement plan for vulnerable populations, overburdened communities, and other historically or currently marginalized groups; and
- an analysis of gaps and conflicts in state law and programs.

The Governor's Office must develop policy and budget recommendations to the Legislature necessary to implement the state's climate commitment by December 31, 2021. The governance structure does not create legal authority for Ecology or other state agencies to enact, adopt, issue an order, or in any way implement additional regulatory programs beyond this act or current law.

Cap and Invest Program. Ecology must implement a GHG emissions cap and invest program (program) to reduce GHG emissions consistent with the statewide emissions limits. The program must track, verify, and enforce compliance through the use of compliance instruments.

By December 1, 2027, and at least every four years thereafter, Ecology must submit a report to the Legislature and the Environmental Justice Council that includes a comprehensive review of the implementation of the program to date, including, but not limited to, outcomes relative to the state's emissions reduction limits, overburdened communities, covered entities, and EITEs.

Program Budget and Timeline. By January 1, 2023, Ecology must begin the program. Ecology must determine an emissions baseline establishing the proportionate share that the total GHG emissions of covered entities bears to the total anthropogenic GHG emissions in the state during 2015 through 2019, based on reported data.

The first compliance period is January 1, 2023, through December 31, 2026. By October 1, 2022, Ecology must adopt annual allowance budgets for the first compliance period of the program. Data reported from 2015 through 2019 is sufficient for adopting annual allowance budgets and demonstrating compliance for the first compliance period.

The second compliance period is January 1, 2027, through December 31, 2030. By October 1, 2026, Ecology must add to its emissions baseline by incorporating the proportionate share the total GHG emissions of new covered entities in the second compliance period bear to the total anthropogenic GHG emissions in the state during 2023 through 2025. In determining the addition to the baseline, Ecology may exclude a year from the determination if it has been an outlier due to a state of emergency. Ecology must adopt annual allowance budgets for the second compliance period. Data reported to Ecology for 2023 through 2025 is sufficient for adopting annual allowance budgets and demonstrating compliance under the second compliance period of the program.

For calendar years 2031 through 2040, Ecology must adopt by rule the annual allowance budgets. The annual allowance budgets must be set to achieve the covered entities' share of reductions necessary to meet the 2030, 2040, and 2050 statewide emissions limits. Ecology must reduce the annual allowance budget in an amount equivalent to offset use so the use of offsets as compliance instruments does not prevent the state from achieving the emissions limits. Ecology must adopt annual allowance budgets that provide progressively equivalent reductions year over year. An allowance distributed under the program does not expire and

may be held or banked.

By December 31, 2027, and December 31, 2035, Ecology must evaluate the performance of the program, including the reduction of GHG, and make adjustments to annual allowances budgets if needed to achieve the 2030 and 2040 emissions limits.

By December 31, 2040, and December 31, 2045, Ecology must complete additional evaluations of the program and make adjustments in annual allowance budgets if needed to ensure that covered entities achieve their proportionate share of the 2050 emission limits.

Participating Entities. Covered entities are required to register to participate in the program. At the beginning of the first compliance period, and for all subsequent compliance periods, a covered entity is a person who has reported emissions or provided data that indicates emissions equal or exceed a threshold of 25,000 metric tons of carbon dioxide equivalent for:

- facilities;
- electricity generated in the state;
- first jurisdictional deliverer importing electricity into the state from specified or unspecified sources;
- fuel suppliers other than natural gas; and
- natural gas suppliers to non-covered entities.

Ecology, in consultation with the Department of Commerce (Commerce) and the UTC, must adopt a methodology for addressing imported electricity associated with a centralized electricity market.

The amounts for fuel products produced or imported with a documented final point of delivery outside of Washington and combusted outside of Washington for fossil fuel suppliers are excluded for purposes of program coverage. Industrial gas customers who purchase gas from someone other than a natural gas company are responsible for their own emissions.

At the beginning of the second compliance period, and for all subsequent compliance periods, a covered entity is a person who has reported emissions or provided data that indicate emissions equal or exceed a threshold of 25,000 metric tons of carbon dioxide equivalent for waste to energy facilities used by county and city solid waste management programs.

Beginning January 1, 2031, and for all subsequent compliance periods, a covered entity is a person who has reported emissions or provided data that indicate emissions equal or exceed a threshold of 25,000 metric tons of carbon dioxide equivalent for:

- landfills used by county and city solid waste management programs; and
- railroad companies.

Landfills with gas capture systems that capture at least 75 percent of landfill gas and produce renewable natural gas or electricity from landfill gas are not covered entities under the program. It is the intent of the Legislature to adopt a GHG reduction policy specific to landfills, and if such a policy is not enacted by January 1, 2030, the requirements of the program relative to landfills take full effect.

Ecology must notify the Legislature whenever a covered entity is no longer covered by the cap and invest program. A covered entity whose emissions fall below the threshold has a compliance obligation until the end of the compliance period. An entity is no longer a covered entity when its emissions are below the threshold during the entire compliance period or operations have ceased at its facility that is required to report GHG emissions. However, if Ecology notifies a person that its facility's emissions are within 10 percent of the threshold, the person will continue to be designated as a covered entity to ensure equity among all covered entities.

An opt-in entity is a person responsible for GHG emissions that is not a covered entity but may voluntarily participate and register in the program. An opt-in entity must meet the same requirements for registration and compliance obligations as a covered entity. An opt-in entity may opt out of the program by giving Ecology notice six months prior to the end of the compliance period, but will have compliance obligations through a compliance period. An opt-in entity is not eligible to receive allowances directly distributed to emissions-intensive, trade-exposed (EITE) industries, electric utilities, or natural gas companies under this program.

A general market participant is not a covered or opt-in entity, but may also voluntarily register in the program to purchase, trade, hold, sell, transfer, or retire compliance instruments. Federally recognized tribes and federal agencies may elect to participate in the program as opt-in entities or general market participants. Ecology must maintain a public roster of all covered entities, opt-in entities, and general market participants on its website. Participating entities must describe any direct or indirect affiliation with other registered entities.

Ecology must adopt rules for program registration procedures.

Exemptions. Regardless of reporting requirements, the emissions exempt from coverage are from:

- the combustion of aviation fuel;
- watercraft fuels;
- coal-fired electric generation, exempt from GHG limitations and requirements;
- carbon dioxide emissions from the combustion of biomass or biofuels that have a 40 percent lower GHG emissions based on a full-life cycle analysis compared to petroleum fuels;
- motor vehicle and special fuel used for agricultural purposes by a farm fuel user; and
- national security facilities.

Ecology must determine a method for expanding the exemption for agricultural purposes to include fuels used for transporting agricultural products on public highways for five years.

Auctions. Ecology must distribute allowances through a maximum of four auctions annually. The auction may include allowances from the current year annual allowance budgets and allowances yet to be distributed from prior allowance budget years. Ecology must engage a qualified, independent contractor to run the auctions. Additionally, Ecology must engage a qualified financial services administrator to hold and evaluate bid guarantees and to inform Ecology of the value of the bid guarantees when the bids are accepted.

Registered entities in good standing may participate in auctions. A registered entity must submit an application to participate and is only eligible to participate in an auction after receiving approval by Ecology. Ecology may require a bid guarantee in an amount greater than or equal to the sum of the maximum value of bids that will be submitted by the registered entity.

Registered entities with a direct corporate association are subject to the following auction purchase limits:

- covered or opt-in entity may not buy more than 10 percent of allowances offered during a single auction;
- general market participants may not buy more than 4 percent of allowances offered during a single auction and may not in aggregate own more than 10 percent of total allowances to be issued in a calendar year; and
- no registered entity may buy more than its bid guarantee or allowances that would exceed its holding limit at the time of the auction.

Ecology must adopt rules to guard against bidder collusion and minimize the potential for market manipulation. A registered entity may not disclose bidding information such as intent to participate in an auction, auction approval status, bidding strategy, bid price or quantity, or bid guarantee. Ecology may cancel or restrict an approved application or reject a new application to participate in an auction if it determines that the registered entity has provided false or misleading facts, withheld material information that could influence a decision by Ecology, or violated auction rules or registration requirements. Ecology may cancel or restrict participation permanently or for a specified number of auctions, which is in addition to any other penalties and fines.

Ecology must consider the number of no cost allowances in the marketplace in setting the number of allowances offered at each auction and only offer a number of allowances at each auction that will enhance the likelihood of achieving the statewide emission limits.

Emissions Intensive, Trade-Exposed. Facilities owned or operated by a covered entity must receive an allocation of allowances at no cost if it is classified as an EITE, as determined by being engaged in one or more of the processes described within specified North American

industry classification system codes. Ecology must adopt by rule objective criteria to identify EITE manufacturing businesses during the second compliance period. If a manufacturing business can demonstrate it meets this criteria, it is eligible for free allocation of allowances as an EITE industry under Ecology's rules, which must consider the locations of facilities potentially identified as EITE manufacturing businesses relative to overburdened communities

For the first compliance period, the annual allocation of no cost allowances for direct distribution to a facility identified as EITE must be equal to the facility's baseline carbon intensity established using data from 2015 through 2019, or other data allowed, multiplied by the facility's actual production for each calendar year during the compliance period. If an EITE facility is not able to feasibly determine a CI benchmark, it may elect to use a mass-based baseline that does not vary based on changes in production volumes. For facilities using the mass-based approach, the allocation of no cost allowances must be equal to the facility's mass-based baseline using data from 2015 through 2019, or other data allowed. For the second compliance period and each subsequent compliance period, the annual allocation of new cost allowances must be adjusted according the specified benchmark reduction schedules multiplied by the facility's actual production during the period.

EITE facilities must be awarded no cost allowances equal to:

- 100 percent of the CI benchmark or mass-based baseline for each year of the first compliance period;
- 97 percent of the CI benchmark or mass-based baseline for each year of the second compliance period; and
- 94 percent of the CI benchmark or mass-based baseline for each year of the third compliance period.

An aerospace products and parts manufacturing facility using a mass-based baseline must receive an additional no cost allocation to accommodate an increase in production which increases its emissions above the baseline on a basis equivalent in principle to those awarded to entities using a carbon intensity benchmark. Ecology must establish methods to award additional no cost allowance allocations for EITE facilities, if appropriate based on projected production, to achieve a similar on-going result through the adjustment of the facility's mass-based baseline.

An EITE facility's benchmark can also be adjusted prior to the second or third or subsequent compliance periods if an EITE facility demonstrates additional reductions in CI are not technically or economically feasible based on a facility’s best available technology analysis. Ecology may make adjustments based on specified changes for the EITE facility.

Ecology must provide a report to the Legislature describing alternative methods for determining the amount and schedule of allowances to be provided to EITE facilities from 2035 to 2050. The report must include best practices in ensuring against emissions leakage and economic harm to businesses in carbon pricing programs. If the Legislature does not

adopt a compliance obligation for EITE facilities by December 1, 2027, those facilities must continue to receive allowances as provided in the third compliance period.

If the actual emissions of an EITE facility exceeds the facility's no cost allowances assigned in a compliance period, the EITE facility must purchase additional compliance instruments to equal these emissions. An EITE facility must be allowed to bank unused allowances to be used for future sale and investment in best available technology when economically feasbile. Ecology may limit offset credit use if the no cost allowances plus offset credits exceed one hundred percent of total compliance.

A curtailed facility can retain, but not trade, sell, or transfer, allowances except to transfer to a new operator of the facility operating under the same industrial classification. All unused allowances must be transferred to the emissions containment reserve if the curtailed facility becomes a closed facility. A curtailed facility is not eligible to receive free allowances during a period of curtailment.

An an owner or operator of more than one facility receiving no cost allowances for EITE facilities may transfer allowances among the eligible facilities.

Rules adopted by Ecology for allocation of allowances at no cost to EITE facilities must include protocols for allocating allowances to an eligible facility built after the effective date of section. These protocols must include consideration of products and criteria pollutants produced by the facility, as well as local environmental and health impacts associated with the facility. The protocols for a facility built on tribal lands or determined to impact tribal lands or resources must be developed in consultation with affected tribal nations.

During the 2022 regular legislative session, Ecology must have agency request legislation developed in consultation with EITEs, covered entities, environmental advocates, and overburdened communities that outlines a compliance pathway specific to EITEs for achieving their proportionate share of the state's emission reduction limits through 2050. If, by April 1, 2023, the Legislature has not considered and enacted Ecology's request legislation, no expenditures may be made from the Carbon Emissions Reduction Account, the CI Account, or the Air Quality and Health Disparities Improvement Account.

Electric Utilities. The Legislature intends to allocate allowances to all consumer-owned utilities (COUs) and investor-owned electric utilities (IOUs) subject to CETA to mitigate the cost burden of the program on electricity customers.

In consultation with Commerce and the UTC, Ecology must adopt rules for establishing the methods and procedures for allocating allowances and set allocation schedules for the provision of allowances at no cost to COUs or IOUs. These allocations must be consistent with a forecast of each utility’s supply and demand and the cost burden resulting from the inclusion of the covered entities in each compliance period.

Allowances allocated at no cost to COUs and IOUs must be consigned to auction for the benefit of ratepayers, deposited for compliance, or a combination of both. Utilities may use allowances for compliance equal to their covered emissions in any calendar year they were not subject to potential penalty under CETA. Under no circumstances may utilities receive any free allowances after 2045.

Ecology must allocate allowances at no cost to the electric utility or power marking administration providing electricity to an EITE entity, unless allowances have already been allocated, in an amount equal to the forecasted emissions for the entity's electricity consumption for the compliance period. Ecology may allow for allowances to be transferred between a power marking administration and electric utility and used for direct compliance.

Rules establishing the allocation of allowances to COUs and IOUs to consider the impact of electrification of building, transportation, and industry on the electricity sector. Nothing in this section affects the requirements of CETA.

A COU that is party to a contract that meets certain conditions must be issued no cost allowances for emissions associated with imported electricity, to prevent impairment of the value of the contract to either party.

Natural Gas Companies. Natural gas utilities must be allocated allowances at no cost for the benefit of ratepayers. Ecology must set allocation schedules by rule, in consultation with the UTC, to provide allowances at no cost equal to emissions for the sector and declining consistent with the cap. Allowances must be provided at no cost for the benefit of ratepayers, deposited for compliance, or a combination of both.

Sixty-five percent of the no cost allowances, increasing at 5 percent annually, must be consigned to auction for the benefit of customers, prioritizing low-income customers. Revenues from allowances sold at auction must be returned by providing nonvolumetric credits on ratepayer bills, prioritizing low-income customers, or may be used to minimize cost impact on low-income, residential, and small business customers for a actions such as weatherization, decarbonization, conservation and efficiency services, and bill assistance. The customer benefits provided from allowances consigned to auction must be in addition to existing requirements in law.

Except for low-income customers, the nonvolumetric credits are reserved exclusively for customers at locations connected to a natural gas utility's system on the effective date of the act. These credits may not be provided to customers of the gas utility at a location connected to the system after the effective date of the act.

Natural gas utilities must provide to Ecology copies of GHG reports filed with the U.S. Environmental Protection Agency, and continue reporting to receive no cost allowances.

Emissions Containment Reserve. To help ensure that the price of allowances available for auction in the program remains sufficient to incentivize reductions in GHG emissions, Ecology must establish an Emissions Containment Reserve and set an emissions containment reserve trigger price by rule. The price must be set at a reasonable amount above the auction floor price and equal to the level established in linked jurisdictions .

If the price of allowances falls below the emissions containment reserve trigger price, Ecology will automatically withhold allowances from auction. Any allowances that have been withheld from auction must be transferred to the Emissions Containment Reserve Account.

Allowances must be transferred to the emissions containment reserve when allowances are unsold in auctions, facilities are curtailed or closed, or when facilities fall below 25,000 metric tons.

Allowances must be distributed from the Emissions Containment Reserve by auction for new covered and opt-in entities, provided the distribution will not jeopardize the state's emissions reduction limits. If the reserve is exhausted, allowances must be distributed from the allowance price containment reserve by auction for new entities.

Allowance Price Containment Reserve. To help minimize price volatility and limit the potential for extraordinary prices, Ecology must adopt by rule auction floor and auction ceiling prices. The auction floor price shall increase by a predetermined amount every year. Ecology may not sell allowances at bids lower than the auction floor prices.

An Allowance Price Containment Reserve must be designed as a mechanism to contain compliance costs in the event of unanticipated high costs for compliance instruments. For the first compliance period, Ecology must place no less than 2 percent of the total number of allowances available from the allowance budgets in the reserve. Only covered and opt-in entities may participate in the auction of allowances from the Allowance Price Containment Reserve. A reserve auction must be separate from auctions of other allowances. However, the process for the reserve auctions is the same as the process for described above for general auctions. The auction proceeds must be deposited in the Climate Investment Account.

Ecology must adopt rules to:

- hold auctions of allowances from the Allowance Price Containment Reserve when the settlement prices in the preceding auction approach the auction ceiling price;
- specify holding limits that determine the maximum number of allowances to be held for use or trade by a registered entity at any one time;
- set the reserve auction floor price before the reserve auction and may establish multiple price tiers;
- establish the requirements and schedule for reserve auctions; and
- establish the amount of allowances to be placed in the reserve after the first

compliance period ends.

Price Ceiling. A price ceiling and price containment reserve are established to provide cost protection for facilities obligated to comply with the program. The price ceiling shall be set at a level sufficient to facilitate investments to achieve emission reductions beyond those enabled by the price ceiling.

Ecology must issue price ceiling units for sale at a fixed price if no allowances remain in the allowance price containment reserve. Funds raised in connection with sales of price ceiling units must be expended to achieve emissions reductions.

Offset Credits. A portion of a covered or opt-in entity's compliance obligation may be met through offset credits from projects that result in GHG reductions or removals that are real, permanent, quantifiable, verifiable, and enforceable. Off-set projects must be in addition to GHG reductions or removals otherwise required and must be certified by a recognized registry within two years prior to the effective date of the section of the act creating offset credits. At least 50 percent of the offset credits must be from projects that provide direct environmental benefits in Washington State during the first compliance period and the remaining offset projects must be in a linked jurisdiction with Washington. For the second compliance period, at least 75 percent of offset credits must be from projects that provide direct environmental benefits in Washington. However, Ecology may reduce the requirement if it determines there is not sufficient offset supply in the state to meet offset demand.

A covered or opt-in entity may use offset credits to meet no more than 5 percent of compliance obligations during the first compliance period. During the second compliance period, no more than 4 percent of compliance obligations may be met through offset credits. Offset projects on federally recognized tribal land do not count against the off-set credit limits for covered or opt-in entities and may be no more than 3 percent of compliance obligation for the first compliance period and 2 percent for the second compliance period. Beginning January 1, 2031, these limits continue to apply unless modified by rule after a public consultation process.

The offset credit limits may be modified by rule to ensure the proportionate share of statewide emissions limits are achieved and alignment with linked jurisdictions. The offset credit limits may also be reduced for a specific entity if Ecology, in consultation with the Environmental Justice Council, determines the covered entity has or is likely to contribute substantively to cumulative air pollution burden in an overburdened community or violate any permits where the violation may result in increased emissions.

Ecology must develop rules for protocols to establish offset projects and secure offset credits used to meet compliance obligations. Ecology must take into consideration standards, rules, or protocol for offset projects and credits established by other jurisdictions with comparable programs. Ecology must also encourage opportunities for the

development of offset projects in Washington by adopting offset protocols that reduce transaction costs and make use of aggregation or other mechanisms to increase the development of offset and carbon removal projects by landowners, including small forest landowners.

Ecology must adopt a process for monitoring and invalidating offset credits to ensure the credit reflects emissions reductions. If an offset credit is invalidated, the covered or opt-in entity must transfer replacement credits or allowances within six months. A covered or opt-in entity is subject to a penalty if fails to transfer replacement credits or allowances. Offset credits used may not be in addition to, or allow for an increase in established allowance budgets. Offset credits must be registered and tracked as a compliance instrument.

Assistance Program for Offsets on Federally Recognized Tribal Lands. To ensure a sufficient number of high quality offset projects are available, Ecology must establish an assistance program for offset projects on federally recognized tribal lands. The assistance may include funding or consultation to assess a project's technical feasibility, investment requirements, development, and operation costs, expected returns, administrative and legal hurdles, and project risks and pitfalls. Ecology may provide funding or assistance upon request by a federally recognized tribe. The Legislature intends to provide not less than $5 million in the operating budget for this purpose.

Small Forestland Owner Work Group. The Department of Natural Resources must contract with a Washington nonprofit that can demonstrate a membership of at least 1000 small forestland owners and promotes the sustainable stewardship of family forestland to establish and implement a small forestland owner work group. The purpose of the work group is to identify possible carbon market opportunities, including the provision of qualifiable offset credits, and other incentive-based GHG reduction programs that Washington landowners may be able to access, including compliance markets in other jurisdictions, voluntary markets, and federal, state, and private programs for forestlands.

The work group must:

- provide recommendations for implementation and funding a pilot program to develop an aggregator account that will pursue carbon offset projects for small forestland owners in Washington;
- coordinate with Ecology on the development of offset protocols;
- develop a framework and funding proposal for establishing a program to link interested small forestland owners with incentive-based carbon reducing programs that facilitate adoption of forest practices and increase carbon storage and sequestration in forests and wood products; and
- recommend policies to support the implementation of incentives for participation in carbon markets.

By December 1, 2022, the work group must transmit a final report to Ecology that provides recommendations for incentives, the implementation of incentives, payment structures

necessary to support small forest landowners, and whether the work group should be extended or made permanent.

Allowance Trading and Tracking Compliance Instruments. Ecology must use an online electronic tracking system to register entities, issue compliance instruments, track ownership and transfers of compliance instruments, facilitate program compliance and support market oversight.

Covered and opt-in entities must use the following two accounts: a compliance account to transfer allowances to Ecology to retire; and a holding account for allowances to be bought, sold, or traded. The number of allowances in a holding account may not exceed the holding limit of the entity. General market participants are allowed an account to hold, trade, sell, or transfer allowances. Ecology must maintain an account for retired allowances transferred by registered entities and from the voluntary renewable reserve account. A voluntary renewable reserve account is a holding account maintained by Ecology for retiring allowances for voluntary renewable electricity generation, directly delivered to the state and will not be sold or used to meet any other mandatory requirements, on behalf of voluntary renewable energy purchases or end users. Ecology must maintain a regularly updated searchable website that shows the contents of each holding account, including but not limited to the number of allowances.

Enforcement. All covered and opt-in entities must comply with all requirements for monitoring, reporting, holding, and transferring emission allowances and other provisions of this act. If a covered entity or opt-in entity fails to submit sufficient compliance instruments to meet its compliance obligations by the specified transfer dates, it must submit a penalty of four allowances for every one allowance that is missing within six months.

If a covered entity or opt-in entity fails to submit penalty allowances, Ecology must issue a civil penalty of up to $10,000 for each penalty allowance that is not submitted per day. Ecology will also issue a penalty of up to $10,000 per day per violation for failure to comply with program rules, and may issue a penalty up to $50,000 per day per violation in cases of market manipulation.

All penalties must be deposited into the Climate Investment Account (CI Account). Appeals of orders and penalties must be to the Pollution Control Hearings Board. An electric utility or natural gas utility must notify its retail customers and the Environmental Justice Council within three months of paying a monetary penalty for failure to comply with the requirements of the program.

Linkage with Other Jurisdictions. Ecology must seek to enter linkage agreements with other jurisdictions with established allowance-based GHG reduction programs under circumstances in order to broaden GHG emissions reduction opportunities to reduce costs of compliance, enable joint allowance markets and unified tracking for compliance

instruments, enhance market security, reduce program administrative costs, and provide consistent requirements across jurisdictions.

Linkage agreements must include provisions relating to auctions, holding limits, GHG reporting and verification, offset protocols, enforcement, program registry, compliance instruments, coordinated administrative and technical support, public notice an participation, and processes to withdraw from the agreement.

Ecology may enter into a linkage agreement with another jurisdiction after conducting an environmental justice assessment. Before entering into a linkage agreement, Ecology must evaluate and make a finding whether the aggregate number of unused allowances in a linked program would reduce the stringency of Washington's program and the state's ability to meet its emissions limits. Ecology must find that the linkage agreement meets certain criteria, conduct a public comment process to obtain input and review of the linkage agreement, and consider the input prior to finalizing a linkage agreement. The criteria must include:

- the linking jurisdiction has provisions to ensure distribution of benefits from the program to vulnerable populations and overburdened communities;
- a determination by Ecology that the agreement will not yield net adverse impacts to either jurisdiction's highly impacted communities, relative to the baseline level of emissions; and
- not adversely impact Washington's ability to achieve statewide emissions limits.

If Ecology determines a full linkage agreement is unlikely to meet the above criteria, it may enter into a linkage agreement with limitations.

The state retains all legal and policymaking authority over program design and enforcement. Ecology must provide agency request legislation if it finds any provision of the act prevents linking Washington's program with another jurisdiction.

Auction Proceeds Distribution. The auction proceeds must be transferred to the state treasurer for specific deposits first to the Carbon Emissions Reduction (CER) Account and the remaining auction proceeds to the CI Account and Air Quality and Health Disparities Improvement Account. The deposits to the CER Account are as follows:

- $127,341,000 for FY 2023;
- $356,697,000 for FY 2024;
- $366,558,000 for FY 2025; and
- $359,117,000 each year for fiscal years 2026 through 2037.

The deposits into the CER Account must not exceed $5.2 billion over the first 16 years. For FY 2038 and each year thereafter, 50 percent of the proceeds must be deposited to the CER Account and 50 percent to the CI Account and Air Quality and Health Disparities Improvement Account.

Carbon Emissions Reduction Account. The CER Account is created in the state treasury and is subject to appropriation. Expenditures from the account may only be used for transportation carbon emissions reducing purposes and may not be used for 18th amendment purposes, other than as specified for the account, including investments in alternatives and reductions to single occupancy passenger vehicle use through alternative fuel infrastructure and incentives, and emission reduction programs for freight, ferries, and port activities.

Climate Investment Account. The CI Account is created in the state treasury, and all receipts from the auction of allowances must be deposited there, unless otherwise specified. Projects funded from the CI Account must meet high workforce labor standards, including employer paid sick leave programs, family sustaining wages, pay equity based on gender identity and race, career development opportunities, and maximize access to economic benefits for local workers and diverse businesses.

Moneys in the CI Account may only be used for projects and programs that achieved the purposes of the program and must first be appropriated for the administration of the program, not to exceed 5 percent of the total receipts of funds from the auction of allowances. Beginning July 1, 2024, and annually thereafter, the state treasurer must distribute the funds in the CI Account as follows:

- 75 percent to the Climate Commitment Account; and
- 25 percent to the Natural Climate Solutions Account.

Biennially, the Legislature must review these allocations based on the changing needs of the state in meeting its clean economy and GHG reduction goals in a timely, economically advantageous, and equitable manner. Moneys in either account may not be used for projects that would violate tribal treaty rights or result in significant long-term damage to critical habitat or ecological functions. Investments must result in long-term environmental benefit and increased resiliency to the impacts of climate change.

The Climate Commitment Account. The Climate Commitment Account is created in the state treasury and is subject to appropriation. Projects, activities, and programs eligible for funding from the account must be physically located in Washington State and include the following:

- implementing the working families tax tebate;
- supplementing the growth management planning and environmental review fund;
- supporting programs, activities, or projects that:
    1. reduce and mitigate GHG and co-pollutants in overburdened communities, including strengthening the air quality monitoring network to measure, track, and better understand air pollution levels and trends to inform the analysis, monitoring, and pollution reduction measures required under the environmental justice review;
    2. deploy renewable energy resources, distributed generation, energy storage, demand-side technologies and strategies, and other grid modernization projects;

3. increase energy efficiency or reduce GHG emissions of industrial facilities;
4. achieve energy efficiency or emission reduction in the agricultural sector, including grants, loans or financial incentives for eligible funds uses under the Sustainable Farms and Fields Grant Program ;
5. increase energy efficiency in new and existing buildings or promote low-carbon architecture;
6. promote electrification and decarbonization of new and existing buildings;
7. improve energy efficiency, including high-efficiency electric appliances and equipment for space and water heating;
8. assist with clean energy transition and assist affected workers or people with lower incomes during the transition to a clean energy economy, or grow and expand clean manufacturing capacity, including improving energy affordability and reduce energy burden for people with lower incomes and higher transportation fuel burden for rural residents; community renewable energy projects that allow participants to own or receive the benefits at reduced or no cost; programs, activities or worker-support projects for bargaining unit and nonsupervisory fossil fuel workers affected by the transition away from fossil fuels to a clean energy economy; direct investment in workforce development; initiatives to develop a forest health workforce; or transportation, municipal service delivery and technology investments that increase a community's capacity for clean manufacturing;
9. allow the diversion of organic materials from landfills and waste to energy facilities or methane capture;
10. deploy carbon dioxide removal; and
11. support efforts to mitigate and adapt to the effects of climate change affecting Indian tribes, including capital investments in support of the relocation of tribes located in areas at heightened risk due to anticipated seal level rise, flooding, or other disturbances caused by climate change and for these purposes the Legislature intends to dedicate at least $50 million per biennium.

Natural Climate Solutions Account. The Natural Climate Solutions Account is created in the state treasury subject to appropriation. Moneys in the account are intended to increase the resilience of the state's waters, forests, and other vital ecosystems to the impacts of climate change, conserve working forestlands at the risk of conversion, and increase their carbon pollution reduction capacity through sequestration, storage, and overall ecosystem integrity. Moneys in the account must be spent in a manner consistent with existing and future assessments of climate risks and resilience from the scientific community and expressed concerns of and impacts to overburdened communities.

Moneys may be allocated for the following purposes:

- Clean water investments that improve resilience from climate impacts, and funding must be used to:
    1. restore and protects estuaries, fisheries, and marine shoreline habitats, and prepare for sea level rise including making fish passage correction investments;

2. increase carbon storage in the ocean or aquatic and coastal ecosystems;
3. remediate and adapt to impacts of ocean acidification;
4. reduce flood risk and restore natural floodplain;
5. increase sustainable supply of water and improve aquatic habitat;
6. improve stormwater infrastructure;
7. preserve or increase carbon sequestration in forests, forested wetland, agricultural soils, tidally influence agricultural or grazing lands, or freshwater, saltwater, or brackish aquatic lands; or
8. preserve or establish, or both, carbon sequestration by protecting or planting trees in marine shorelines and freshwater riparian areas sufficient to promote climate resilience, protect cold water fisheries, and achieve water quality standards;

- Healthy forest investments to improve resilience from climate impacts, and funding must be used for projects and activities that will:
    1. increase forest and community resilience to wildfire;improve forest health; or
    2. prevent emissions through preserving natural lands from the threat of conversion to development, through actions that include assistance programs such as the forest riparian easement program and the family forest fish passage program. It is the intent of the Legislature that no less than $10 million per biennium from Natural Climate Solutions Account be expended for the Forestry Riparian Easement Program or for riparian easement projects funded under the Agricultural Conservation Easements Program, or similar riparian enhancement programs.

Air Quality and Health Disparities Improvement Account. The Air Quality and Health Disparities Improvement Account is created in the state treasury subject to appropriation. The account is established to fund the air monitoring network and reduce health disparities in overburdened communities. It is the intent of the Legislature that not less than $20 million per biennium be dedicated to the account for these purposes.

Greenhouse Gas Reporting and Verification. Ecology must adopt rules requiring persons to report emissions of GHGs where those emissions from a single facility, or from electricity or fossil fuels sold in Washington by a single supplier or local distribution company, meet or exceed 10,000 metric tons of carbon dioxide equivalent annually. Annual reports must include emissions data for the preceding calendar year and be submitted to Ecology by March 31st of the year in which the report is due. The reporting rules must support implementation of the cap and invest program.

Ecology must establish by rule the methods of verifying the accuracy of emissions reports. Verification requirements apply at a minimum to:

- persons that are required to report GHGs, if those emissions equal or exceed 25,000 metric tons of carbon dioxide equivalent emissions, including carbon dioxide from biomass-derived fuels; or

- persons who have a compliance obligation under the cap and invest program in any year of the current compliance period.

Ecology may adopt rules to accept verification reports from another linked jurisdiction where Ecology deems the methods or procedures are substantively similar.

When a person that holds a compliance obligation under the cap and invest program fails to submit an emissions data report, or fails to obtain a positive emissions data verification statement, Ecology may assign an emissions level for that person.

Ecology may by rule include additional gases to the definition of GHG if the gas has been included in external GHG emission trading programs where Washington has a linkage agreement in effect. Ecology must update its rules whenever needed to ensure consistency with emissions reporting requirements for linked jurisdictions .

Facility Siting. To avoid leakage of emissions to other jurisdictions, in achieving the state's emissions limits, the state must pursue the limits in a manner that recognizes the siting and placement of new or expanded best-in-class facilities with lower carbon emitting processes is in the economic and environmental interests of the state.

In conducing a life-cycle analysis, if required, for new or expanded facilities that require review under the State Environmental Policy Act, a lead agency must evaluate and attribute any potential net cumulative GHG emissions resulting from the project as compared to other existing facilities or best available technology. Covered emissions from an entity that is or will be a covered entity must not be the basis for denial of a permit for a new or expanded facility.

A lead agency or permitting agency must allow a new or expanded facility that is a covered or opt-in entity to satisfy any mitigation requirements for GHG emissions under SEPA by submitting the number of compliance instruments equivalent to its covered emissions during a compliance period

Reporting. By December 1, 2029, the Joint Legislative Audit and Review Committee must perform an analysis of the first five years of the cap and invest program. This analysis must include the costs and benefits of the program using specific metrics, an evaluation of the information summarized by Ecology in its 2027 program evaluation, the total statewide costs of the program per ton of GHG emissions reductions achieved, and an evaluation of the impacts of the program on low-income households.

Ecology must prepare a report that identifies all distributions from all accounts, including recipients of funding, amounts, purpose, end use, whether projects produce reductions in GHGs, the cost per metric ton reduced, and a comparison to other projects to facilitate cost-benefit ratios for projects. Ecology must update the report on its web site no less than once a year and annually submit it to the Legislature by September 30th.

Miscellaneous Provisions. Ecology, in collaboration with interested stakeholders, must develop a proposal for assisting households that, for residential home heating, use fuels that are not electricity or natural gas. If Ecology determines the proposal requires legislative action, it must submit its recommendations for proposed legislation to the Legislature no later than September 15, 2022.

The provisions governing the appointment of Washington's members of the Pacific Northwest Electric Power and Conservation Planning Council are amended to allow both members to reside on the same side of the Cascade Mountains, so long as this deviation does not exceed 12 months in any 10-year period.

Rules. Ecology must adopt to implement the program and may adopt emergency rules for initial implementation of the program, to implement the state omnibus appropriations act for the 2021-2023 fiscal biennium, and to ensure that reporting and other program requirements are determined early for the purpose of program design and early notice to registered entities with a program compliance obligation.

Expiration. Rules adopted by Ecology to implement the program are suspended December 31, 2055, if Ecology determines the 2050 statewide emissions limits have been met for two or more consecutive years.

Preemption. A city, town, county, township, or other subdivision or municipal corporation of the state is prohibited from implementing a charge or tax based exclusively on the quantity of GHG emissions. No state agency may adopt or enforce a program that regulates GHG emissions for a stationary source except as provided under this act. The cap and invest program preempts the the Clean Air Rule.

Votes on Final Passage:

Senate	25	24	
House	54	43	(House amended)
Senate	27	22	(Senate concurred)

Effective: July 25, 2021

Partial Veto Summary:

- Removes section 6, which requires state agencies to offer consultation with federally recognized tribes on all funding decisions under this act.
- Removes section 22, which provides provisions related to compliance obligations for covered or opt-in entities.
- Removes internal cross-references to section 22.

ATTACHMENT 5

2021 PSE Integrated Resource Plan



Chapters 1-9

April 2021

FINAL

pse.com

PSE PUGET SOUND ENERGY



About PSE

As Washington state's oldest local energy company, Puget Sound Energy serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties. Our service territory includes the vibrant Puget Sound area and covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula.

Electric service: All of Kitsap, Skagit, Thurston, and Whatcom counties; parts of Island, King (not Seattle), Kittitas, and Pierce (not Tacoma) counties.

Natural gas service: Parts of King (not Enumclaw), Kittitas (not Ellensburg), Lewis, Pierce, Snohomish, and Thurston counties.

PSE meets the energy needs of its customers, in part, through incremental, cost-effective energy efficiency, procurement of sustainable energy resources and farsighted investment in the energy-delivery infrastructure. PSE employees are dedicated to providing great customer service and delivering energy that is safe, dependable and efficient.

Figure i-1: PSE's Service Area

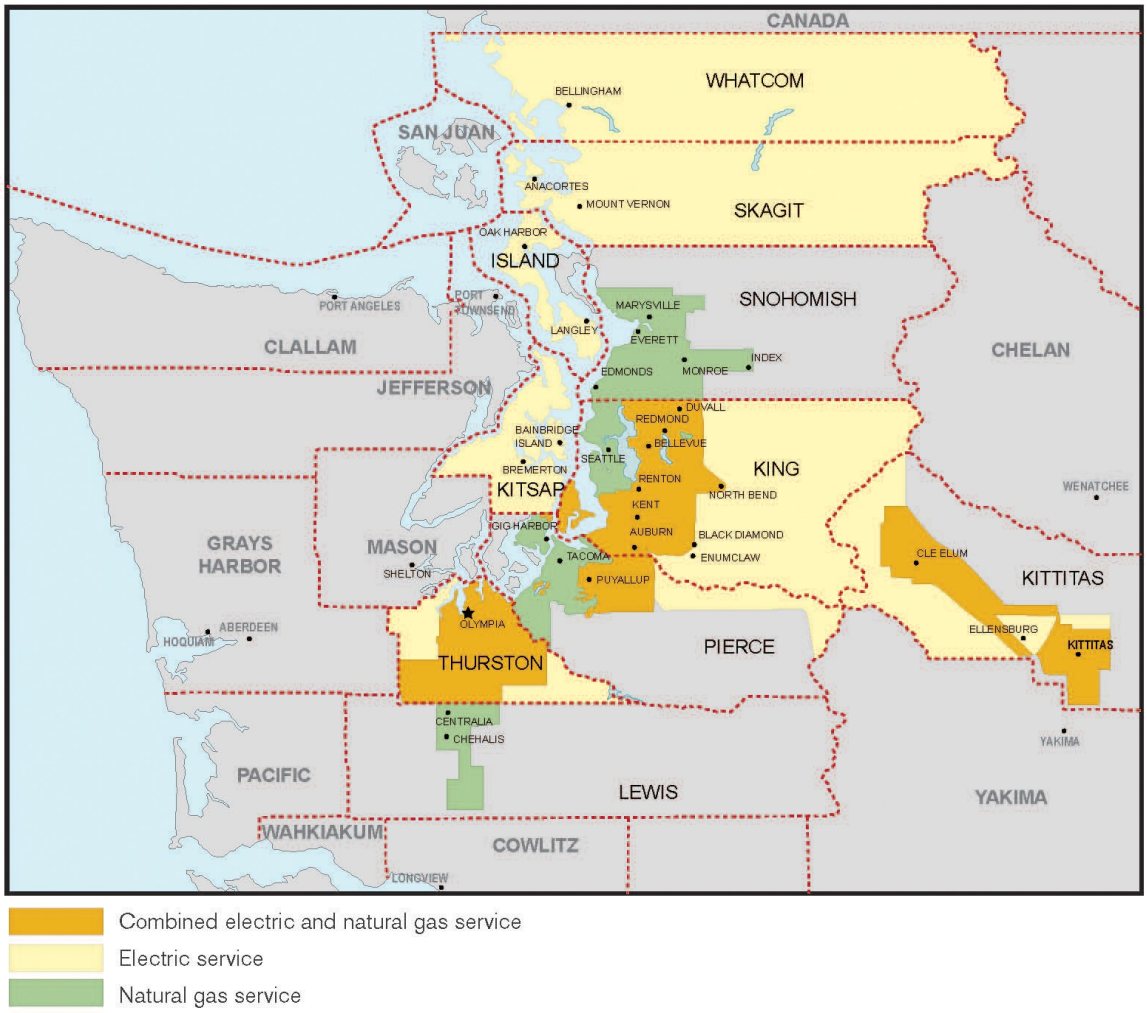




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Definitions and Acronyms

Term/ Acronym	Definition
A4, A5	A standard for converting gases to carbon dioxide equivalents using the Intergovernmental Panel on Climate Change global warming protocols.
AARG	average annual rate of growth
AB 32	California Global Warming Solutions Act of 2006, which mandates a carbon price to be applied to all power generated in or sold into that state.
ACE	Area Control Error
ACE Rule	Affordable Clean Energy Rule. Adopted in 2018, EPA's replacement for the Clean Power Plant Rule.
ADMS	Advanced Distribution Management System, a computer-based, integrated platform that provides the tools to monitor and control distribution networks in real time.
AECO	Alberta Energy Company, a natural gas hub in Alberta, Canada.
AMI	advanced metering infrastructure
AMR	automated meter reading
aMW	The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours).
AOC	Administrative Order of Consent
ARMA	autoregressive moving average
ATC	available transmission capacity
AURORA	One of the models PSE uses for electric resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. AURORA is also used to test electric portfolios to evaluate PSE’s long-term revenue requirements.
BA	Balancing Authority, the area operator that matches generation with load.
BAA	Balancing Authority area
BACT	Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations.
balancing reserves	Reserves sufficient 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 must be able to ramp up and down as loads and resources fluctuate instantaneously each hour.
BART	Best available retrofit technology, an EPA requirement for certain power plant modifications.

Base Scenario	In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making.
Baseload combustion turbines	Baseload combustion turbines are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year. Generally combined-cycle combustion turbines (CCCTs).
baseload resources	Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need.
BAU	business-as-usual
Bcf	billion cubic feet
BEM	Business Energy Management sector, for electric energy efficiency programs.
BES	bulk electric system
BESS	battery energy storage system
BPA	Bonneville Power Administration
BSER	Best system of emissions reduction, an EPA requirement for certain power plant construction or modification.
BTU	British thermal units
CAA	Clean Air Act
CAISO	California Independent System Operator
capacity factor	The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time.
CAP	Corrective action plan, a series of operational steps used to prevent system overloads or loss of customer power.
CAR	Washington State Clean Air Rule
CARB	California Air Resources Board
CBI	customer benefit indicator
CCCT	Combined-cycle combustion turbine. Baseload generating plant that consists of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator.
CCR	coal combustion residuals
CCS	carbon capture and sequestration
CDD	cooling degree day

CEAP	Clean Energy Action Plan
CEC	California Energy Commission
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CFS	conditional firm service, a new transmission product offered by BPA.
CHP	combined heat and power
CI	confidence interval
CIA	cumulative impact analysis
CIA	community impact assessment
C&I	commercial and industrial
CNG	compressed natural gas
CO2	carbon dioxide
CO2e	carbon dioxide equivalents
COE	U.S. Army Corps of Engineers
contingency reserves	Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning.
CPA	conservation potential assessment
CPI	consumer price index
CPP	federal Clean Power Plan
CPP	critical peak pricing or dynamic pricing
CPUC	California Public Utilities Commission
CRAG	PSE's Conservation Resource Advisory Group
C&S	codes and standards
CT	combustion turbine
CVR	conservation voltage reduction
DA	distribution automation
DE	distribution efficiency
DER	distributed energy resources
demand response	Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
demand-side resources	These resources reduce demand. They include energy efficiency, distribution efficiency, generation efficiency, distributed generation and demand response.

DER	Distributed energy resources. Electricity generators like rooftop solar panels that are located below substation level.
DERMS	Distributed Energy Resource Management System
deterministic analysis	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.
DG	distributed generation
distributed energy resources	Small-scale electricity generators like rooftop solar panels, located below substation level.
DLC	direct load control, one of several demand response programs
DMS	distribution management system
DOE	U.S. Department of Energy
DOH	Washington State Department of Health
DR	demand response
DSM	demand-side measure
DSM	demand-side management
DSO	Dispatcher Standing Order
DSP	Delivery System Planning
DSR	demand-side resources
Dth	dekatherms
dual fuel	Refers to peakers that can operate on either natural gas or distillate oil fuel.
EDAM	extended day-ahead market
EE	energy efficiency
EEI	Edison Electric Institute
EHD	environmental health disparities
EHEB	Economic, Health and Environmental Benefits Assessment
EIA	U.S. Energy Information Agency
EIA	Washington State Energy Independence Act
EIM	The Energy Imbalance Market operated by CAISO
EIS	environmental impact statement
EITEs	energy-intensive, trade-exposed industries

ELCC	Effective load carrying capacity. The peak capacity contribution of a resource calculated as the change in capacity of a perfect capacity resource that results from adding a different resource with any given energy production characteristics to the system while keeping the 5 percent LOLP resource adequacy metric constant.
EMC	PSE's Energy Management Committee
energy need	The difference between forecasted load and existing resources.
energy storage	A variety of technologies that allow energy to be stored for future use.
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard
ERU	Emission reduction units. An ERU represents one MtCO2 per year.
ESS	energy storage systems
EUE	Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be).
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	final implementation plan
FLISR	Fault Location, Isolation, Service Restoration
GDP	gross domestic product
GENESYS	The resource adequacy model used by the Northwest Power and Conservation Council (NPCC).
GHG	greenhouse gas
GIS	Geographic Information System
GPM	gas portfolio model
GRC	General Rate Case
GTN	Gas Transmission Northwest
GW	gigawatt
HB 1257	Clean Buildings for Washington Act
HDD	heating degree day
HIC	Highly impacted communities
HILF	high-impact, low-frequency events
HVAC	heating, ventilating and air conditioning

I-937	Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act.
IAP2	International Association of Public Participation
iDOT	Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value.
IGCC	Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier.
intermittent resources	Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power.
IOU	investor-owned utility
IPP	independent power producer
IRP	integrated resource plan
ISO	independent system operator
ITA	independent technical analysis
ITC	investment tax credit
KORP	Kingsvale-Oliver Reinforcement Project pipeline proposal
kV	kilovolt
kW	kilowatt
kWh	kilowatt hours
LAES	liquid air energy storage
LNG	liquified natural gas
load	The total of customer demand plus planning margins and operating reserve obligations.
LOLE	Loss of load expectation, a reliability metric that measures the number of days per year with loss of load due to load exceeding available system capacity.
LOLH	Loss of load hours (or loss of load energy), a reliability metric that measures the duration of electric service curtailment events (how long outages may last).
LOLP	Loss of load probability, a reliability metric that measures the likelihood of an electric service curtailment event happening.
LP-Air	vaporized propane air
LSR	Lower Snake River Wind Facility
LTCE	long-term capacity expansion model
LTF	long-term firm transmission

LTF PTP	long-term firm point-to-point transmission
MATS	Mercury Air Toxics Standard
MDEQ	Montana Department of Environmental Quality
MDQ	maximum daily quantity
MDth	thousand dekatherms
MEIC	Montana Environmental Information Center
MESA	Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems.
Mid-Columbia (Mid-C) market hub	The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC.
MMBtu	million British thermal units
MMtCO2e	million metric tons of CO2 equivalent
MSA	metropolitan statistical area
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead.
nameplate capacity	The maximum capacity that a natural gas fired unit can sustain over 60 minutes when not restricted to ambient conditions.
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
net maximum capacity	The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads.
net metering	A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE.
NGV	natural gas vehicles
NO2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOS	Network Open Season, a BPA transmission planning process.
NO_x	nitrogen oxides
NPCC	Northwest Power & Conservation Council
NPV	net present value
NRC	Nuclear Regulatory Commission

NREL	National Renewable Energy Laboratories
NRF	Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC.
NSPS	New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction.
NTTG	Northern Tier Transmission Group
NUG	non-utility generator
NWA	non-wires analysis
NWE	NorthWestern Energy
NWGA	Northwest Gas Association
NWP	Northwest Pipeline
NWPP	Northwest Power Pool
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMS	outage management system
OTC	once-through cooling
PACE	PacifiCorp East
PACW	PacifiCorp West
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
peak need	Electric or gas sales load at peak energy use times.
peaker (or peaking plants)	Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators.
peaking resources	Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest.
PEFA	ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program.
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric Company
PGA	purchased gas adjustment
PGE	Portland General Electric
PHES	pumped hydro energy storage

PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Pipeline Inspection, Protection, Enforcement, and Safety Act (2006)
planning margin or PM	These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events.
planning standards	The metrics selected as performance targets for a system's operation.
PLEXOS	An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real time to match changes in supply and demand on a 5-minute basis.
PM	particulate matter
PNUCC	Pacific Northwest Utilities Coordinating Committee
PNW	Pacific Northwest
POD	point of delivery
portfolio	A specific mix of resources to meet gas sales or electric load.
PPA	Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point.
PRP	pipeline replacement program
PSCAA	Puget Sound Clean Air Agency
PSE	Puget Sound Energy
PSEM	Puget Sound Energy Merchant, the part of PSE responsible for obtaining and scheduling the transmission needed to serve PSE loads.
PSIA	Pipeline Safety Improvement Act (2002)
PSRC	Puget Sound Regional Council
PTC	Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to $23 per MWh for a wind project's first 10 years of production.
PTP	Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD).
PTSA	Precedent Transmission Service Agreement
PUD	public utility district

pumped hydro	Pumped hydro 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.
PV	photovoltaic
R&D	research and development
RA	resource adequacy
RAM	Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical reliability.
rate base	The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes.
RCRA	Resource Conservation Recovery Act
RCW	Revised Code of Washington
RCW 19.285	Washington's state's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS)
RCW 80.80	Washington state law that 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.
REC	Renewable energy credit. RECs are intangible assets, which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources.
REC banking	Washington's renewable portfolio standard allows for RECs unused in the current year to be "banked" and used in the following year.
redirected transmission	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
regulatory lag	The time that elapses between establishment of the need for funds and the actual collection of those funds in rates.
REM	Residential Energy Management sector, in energy efficiency programs.

repowering	Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015.
revenue requirement	Rate Base x Rate of Return + Operating Expenses
RFP	request for proposal
RHA	Renewable Hydrogen Alliance
RNG	renewable natural gas
RPS	Renewable portfolio standard. A requirement that electricity retailers acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020.
RTO	regional transmission organization
SCADA	Supervisory control and data acquisition that provides real-time visibility and remote control of distribution equipment
SCCT	Simple-cycle combustion turbine, a generating unit capable of ramping up and down quickly to meet peak resource need. Also called a peaker.
scenario	A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis.
SCC	social cost of carbon, also called SCGHG, social cost of greenhouse gases
SCGHG	social cost of greenhouse gases
SCR	selective catalytic reduction
SEIA	Solar Energy Industries Association
SENDOUT	The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads.
sensitivity	A set of data assumptions based on the Mid Scenario in which only one input is changed. Used to isolate the effect of a single variable.
SEPA	Washington State Environmental Policy Act
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO2	sulfur dioxide
SOFA system	separated over-fire air system
Solar PV	solar photovoltaic technology

Stochastic analysis	Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, natural gas prices, hydro generation, wind generation, loads, plant forced outages and CO2 prices.
supply-side resources	Resources that generate or supply electric power, or supply natural gas to natural gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources.
T&D	transmission and distribution
TailVar90	A metric for measuring risk defined as the average value of the worst 10 percent of outcomes.
TCPL-Alberta	TransCanada's Alberta System (also referred to as TC-AB)
TCPL-British Columbia	TransCanada's British Columbia System (also referred to as TC-BC)
TC-Foothills	TransCanada-Foothills Pipeline
TC-GTN	TransCanada-Gas Transmission Northwest Pipeline
TC-NGTL	TransCanada-Nova Gas Transmission Pipeline
TEPPC	WECC Transmission Expansion Planning Policy Committee
TF-1	Firm gas transportation contracts, available 365 days each year.
TF-2	Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only.
thermal resources	Electric resources that use carbon-based or alternative fuels to generate power.
TOP	transmission operator
transmission redirect	"Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.
Transport customers	Customers who acquire their own natural gas from third-party suppliers and rely on the natural gas utility for distribution service.
TSR	transmission service request
TSEP	Bonneville Power Administration's transmission service request study and expansion process.
UPC	use per customer
VectorGas	An analysis tool that facilitates the ability to model price and load uncertainty.
VERs	variable energy resources

VPP	virtual power plant
VVO	volt-var optimization
WAC	Washington Administrative Code
WACC	weighted average cost of capital
WCI	Western Climate Initiative
WCPM	Wholesale Purchase Curtailment Model
WECC	Western Electricity Coordinating Council
WECo	Western Energy Company
WEI	Westcoast Energy, Inc.
Westcoast	Westcoast Energy, Inc
Wholesale market purchases	Generally short-term purchases of electric power made on the wholesale market.
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
ZLD	zero liquid discharge



1 Executive Summary

The Integrated Resource Plan (IRP) is best understood as a planning exercise that evaluates a range of potential future outcomes, considering customer needs, policies, costs, economic conditions and the physical energy system. It's the starting point for making decisions about what resources PSE may procure in the future.

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1. OVERVIEW

The Integrated Resource Plan (IRP) is a planning exercise that evaluates how a range of potential future outcomes could affect PSE's ability to meet our customers' electric and natural gas supply needs. The analysis considers policies, costs, economic conditions and the physical energy system, and proposes the starting point for making decisions about what resources may be procured in the future.

Plan Highlights

The 2021 PSE electric and natural gas IRPs have been developed during a time of extraordinary change as policy makers, the utility industry and the public confront the challenge of climate change and the necessity to transition to a clean energy future.

PSE is committed to reaching the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and the electric resource plan presented here reflects these changes and goals. It includes:

- significant investments in renewable resources
- accelerated acquisition of energy conservation
- increased use of demand response
- integration of distributed energy resources like residential solar and battery energy storage
- reduced reliance on short-term market purchases in response to the changing western energy market
- inclusion of alternative fuels to operate new generating plants

The preferred portfolio reduces direct carbon emissions from PSE's electric supply by over 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments that enable a significant decrease in the generation from fossil fuel-based resources, and through alternative compliance options that may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects.

Legislation enacted in 2019 requires total natural gas costs to include the social cost of greenhouse gasses and related upstream carbon emissions. As a result of this policy change, the natural gas resource plan focuses on significant, aggressive acquisition of conservation due to the increase in total natural gas costs. Since the natural gas IRP analysis was completed prior to the conclusion of the 2021 Washington state legislative session, it does not include new



legislation that may, if enacted, substantially change the use of natural gas in certain sectors. The requirements of any new legislation will be included in the 2023 natural gas IRP.

It is important to recognize that the IRP does not make resource or program implementation decisions. The IRP is a long-term view of what appears to be cost effective based on the best information we have today about the future. The electric IRP analysis is repeated every four years and updated every two years. The IRP's forecasts and resource additions will change as technology advances, clean fuel options increase, resource costs decline, the wholesale energy market evolves and new policies are established. The IRP includes the Clean Energy Action Plan (CEAP). The Clean Energy Implementation Plan (CEIP) starts where the IRP/CEAP ends and develops specific four-year targets for solutions proposed in the IRP/CEAP, taking into account the equitable distribution of customer benefits and the feasibility of implementation.

Public Participation

Public and stakeholder engagement is an essential part of developing an IRP, and the engagement generated valuable feedback and suggestions from organizations and individuals that helped inform the IRP analysis. Despite the challenges posed by the pandemic, this IRP has been developed with an increased level of public participation:

- 13 public webinars were hosted, recoded and documented, between May 2020 and April 2021.
- 32 email communications were distributed to an IRP audience of over 1,400 members.
- On average, 68 participants joined the webinars and 212 unique individuals participated at least once in the process.
- The re-designed IRP website generated over 14,500 visits.
- 303 stakeholder feedback forms, with 683 stakeholder comments, were received and responded to by PSE.
- 43 scenarios and portfolio sensitivities, developed in partnership with the IRP stakeholders, were analyzed and are documented in Chapters 8 and 9.

All webinar registration information, agendas, presentation materials, technical data files, webinar recordings, chat logs and transcripts, stakeholder feedback forms, and documentation of how stakeholder feedback influenced the IRP are available online at pse.com/irp and in Appendix A.

Public involvement will continue to increase as PSE applies lessons learned from the IRP to development of the CEIP, expands public participation in the delivery system planning process and establishes an Equity Advisory Group to advise PSE as it works to ensure that all PSE customers benefit from the transition to clean energy.

Beyond Net Zero by 2045

In January 2021, PSE pledged to become a **Beyond Net Zero Carbon** energy company by 2045. The goals are aspirational, but the commitment to statewide carbon reduction is steadfast. We pledge to:

- Reduce emissions from PSE electric and natural gas operations and electric supply to net zero by 2030.
- Reach net zero carbon emissions for natural gas sales by 2045 for customer use in homes and businesses, with an interim target of a 30 percent reduction by 2030.
- Go beyond PSE's own emissions to reduce carbon emissions in other sectors by partnering with customers and industry to identify programs and products that will enable a decarbonized region.

We do not have all of the answers yet, but with the right combination of legislative, regulatory, commercial and technological enablers, we think this degree of emission reduction is possible. PSE will leverage its decades of experience with renewable energy projects, conservation and innovation, but we will also need support and cooperation from our partners, stakeholders, developers and the community to achieve success.

Knowing the complexity of the issues involved and the need to meet many different interests, PSE is convening an external advisory committee with representation from a diverse set of community members, partners, technical experts and others.

2. CHANGES IN THE WHOLESALE ELECTRIC MARKET

While the western energy market has had surplus capacity for more than a decade, PSE's 1,500 MW of firm transmission to the Mid-Columbia market hub has served as a cost-effective means of meeting demand by accessing energy supply from the regional power market. However, the supply/demand fundamentals of the wholesale electric market have changed significantly in recent years in two important ways: Region-wide, the wholesale electric market is experiencing tightening supply and increasing volatility.

TIGHTENING SUPPLY. As customers, corporations and state legislatures across the Western Interconnect prefer or require power from clean energy sources, the market's resource mix has changed. Since 2016, nearly 15,000 MW of clean energy resources, namely intermittent wind and solar, and 500 MW of batteries have been added to the Western Interconnect, while at the same time, 12,000 MW of traditional, dispatchable coal and natural gas resources have been retired or mothballed. With less dispatchable generation capacity within the Western Interconnect, market supply/demand fundamentals have tightened.

INCREASING VOLATILITY. In response to tighter supply/demand conditions, volatility has also increased. While wholesale electricity prices remain low, on average, in the Pacific Northwest, the region is starting to experience energy price spikes when there is limited supply. Notable events include the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip, and March 2019, when regional cold temperatures coincided with reduced Westcoast pipeline and Jackson Prairie storage availability. Most recently, in August 2020, a west-wide heat wave caused many entities in the region to take a range of actions from energy alerts to rolling blackouts.

As a result of tightening supply and increasing volatility, regional power suppliers are changing how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility by utility, could be an important step toward improving reliability in the region. Numerous regional entities, including PSE, are collaborating on development of a regional resource adequacy program. Should PSE determine the program meets the needs of PSE customers, it will be incorporated into future resource planning activities.

1 Executive Summary

In the past, PSE's firm transmission capacity from the Mid-Columbia market hub has been assumed to provide PSE with access to reliable market purchases under WSPP, Schedule C[1] contracts through which physical energy can be sourced in the short-term bilateral power markets. Historically, PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. For this IRP, PSE conducted a market risk assessment to evaluate the ongoing availability of these short-term power contracts. The assessment resulted in a recommendation to limit the amount of WSPP, Schedule C contracts for the real-time, day-ahead and term market purchases within the three-year purview of PSE's Energy Supply Merchant. This recommendation will transition the historical 1,500 MW limit to a 500 MW limit by the year 2027. To replace those short-term contracts, PSE will seek firm resource adequacy qualifying capacity contracts, compliant with CETA, that meet PSE's resource adequacy requirements and align with a potential regional resource adequacy program. The peak capacity resource need and the preferred portfolio in this IRP reflect the addition of firm resource adequacy qualifying capacity contracts, while reducing the amount of short-term market purchases.

PSE's recommended approach allows PSE to survey the market for available resource adequacy qualifying agreements, and it allows for the development of the regional resource adequacy program requirements, which will help inform PSE's future needs. PSE commits to ongoing review and evaluation of resource adequacy needs as the region addresses capacity deficits, and we expect to continue to address this high-priority issue in the 2023 IRP progress report. Ongoing technology advancements, the outcome of the All-source Request for Proposal (RFP), and regional resource adequacy program developments are expected to inform the IRP progress report.

1/ https://www.wspp.org/pages/Agreement.aspx

3. ELECTRIC RESOURCE PLAN

The preferred electric portfolio is the result of IRP analyses that evaluate a range of potential future resource portfolios to identify the lowest reasonable cost, least risk portfolios that meet customer needs, policy requirements and support the equitable transition to a clean energy future, while maintaining affordability and reliability for customers. PSE's commitments to these objectives are embodied in the preferred portfolio.

The preferred portfolio should be interpreted as a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource and technology trends today. PSE does not make resource decisions in the context of the IRP; actual resource decisions are based on real costs and feasibility discovered through the resource acquisition process and the Clean Energy Implementation Plan.

Electric Resource Need

Meeting our customers' needs reliably is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

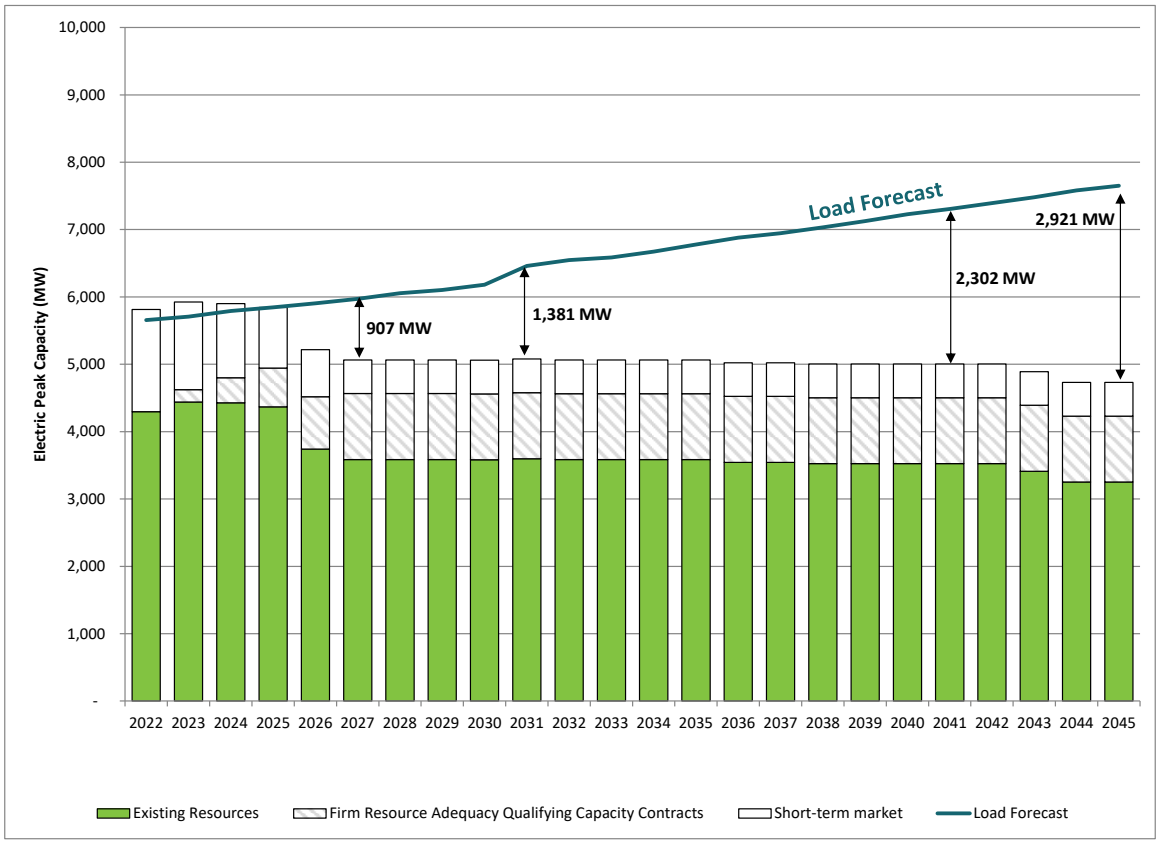
1. **Peak hour capacity reliability**: PSE must have the capability to meet customers' electricity needs reliably during peak demand hours;
2. **Hourly energy**: PSE must have enough energy available in every hour of the year to meet customers' electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the legal requirements of the Energy Independence Act and the Clean Energy Transformation Act.

Peak Hour Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of exiting coal resources, PSE may begin to experience a peak capacity shortfall starting in 2026. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 907 MW by 2027. The 907 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figure 1-1 shows peak capacity need through 2045. After reducing

short-term market purchases as discussed in the previous section, the peak capacity need increases to 1,853 MW by the year 2027.

Figure 1-1: Electric Peak Hour Capacity Need

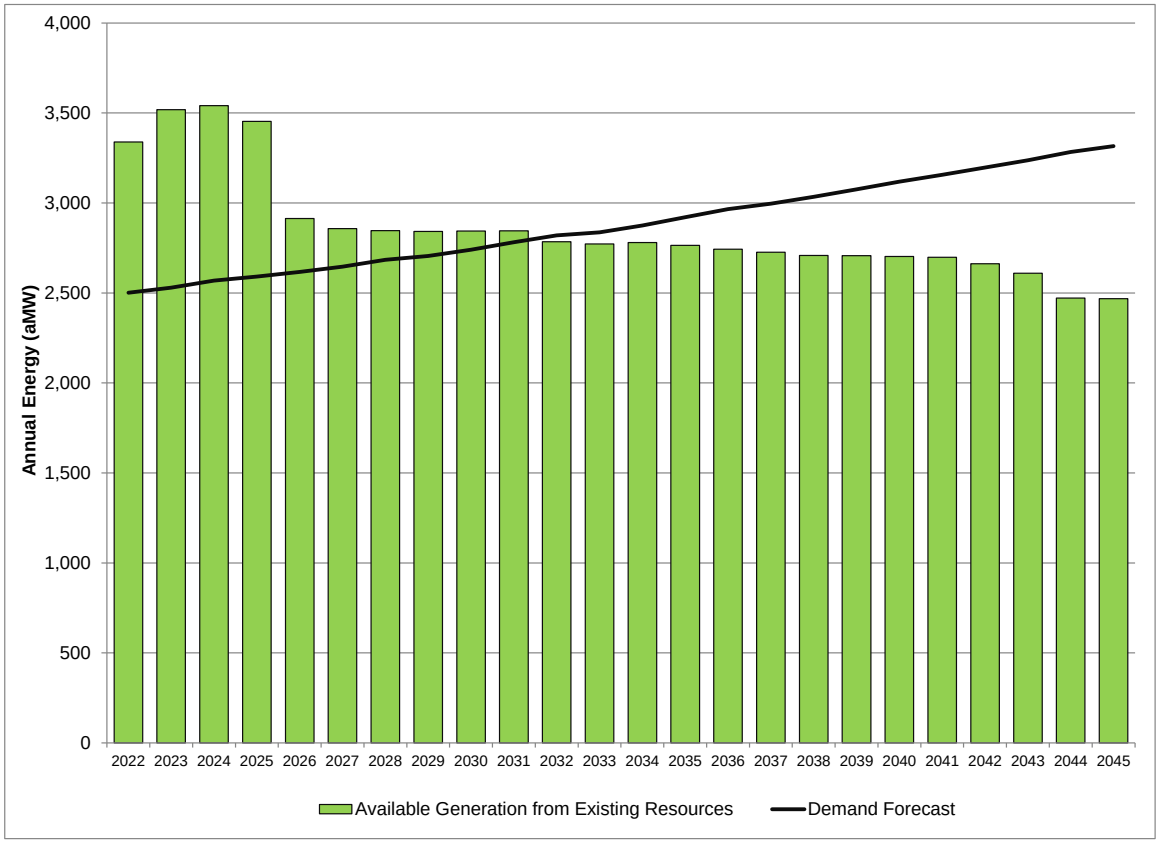


Energy Need

Customer energy needs must also be met in every hour of the year. PSE IRP models require portfolios to supply the amount of energy needed to meet physical loads, and also examine how to do this most economically through existing resources, new resources and purchasing and selling electricity on the energy market. PSE's existing portfolio of supply-side and demand-side resources could generate more energy than needed to meet load on an hourly basis through to 2031; however, it is often more cost-effective to purchase energy from the market than dispatch our existing resources.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the availability of energy resources. This chart does not represent the dispatch of resources or how they will be used to meet PSE's loads, it simply looks at how much energy all the available resources that PSE owns or contracts can potentially generate. For example, PSE's thermal resources are dispatched based on economics, but this chart shows how much energy they could produce if they were run for the entire year. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2031.

Figure 1-2: Annual Energy Position with Energy from All Existing Resources

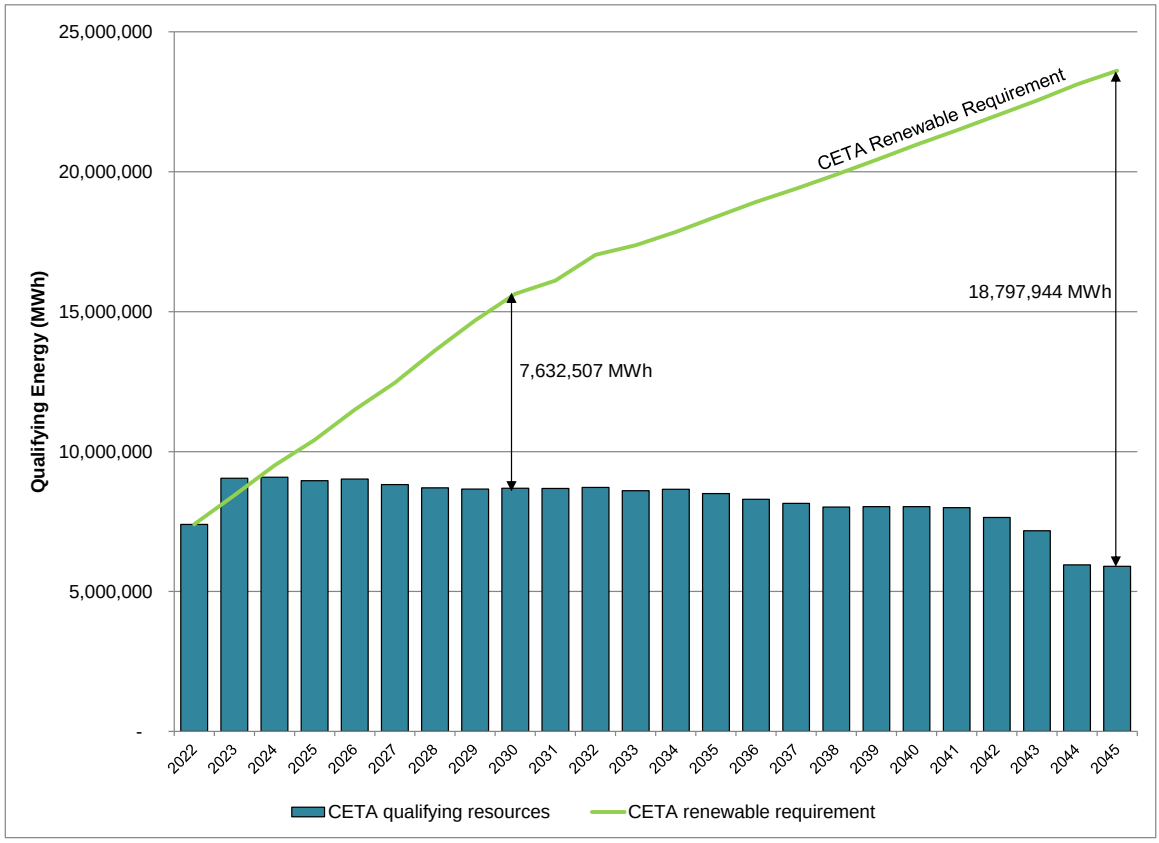


Renewable Energy Need

In addition to reliably meeting the physical needs of our customers, Washington State's Clean Energy Transformation Act (CETA) requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 1-3 illustrates PSE's renewable energy need. For the long-term IRP analysis, a linear ramp to achieve the Clean Energy Transformation Standards in 2030 and 2045 is assumed; however, actual resource acquisitions and the CEIP likely will produce a less linear pathway than shown here. Before any conservation, the renewable energy need is over 7.6 million MWh in 2030. The renewable need is the difference between the green line and the teal bars.

Figure 1-3: Renewable Energy Need



Electric Preferred Portfolio

The IRP preferred portfolio provides a 24-year resource outlook. As explained above, it is not an action plan; rather, it is a forecast of resource additions developed by the modeling that appears most cost effective over the 24-year period given the resource and market trends observed today, while meeting the needs described above and considering customer benefits. Updates will be made every two years and a new long-term IRP analysis will be completed every four years.

The electric preferred portfolio complies with the Clean Energy Transformation Act and is consistent with PSE's beyond net zero carbon goals.

- **ACCELERATED ACQUISITION OF ENERGY CONSERVATION**. The portfolio includes aggressive, accelerated investment in helping customers use energy more efficiently.
- **INCREASED DEMAND RESPONSE**. Compared to previous plans, increased acquisition of demand response appears as a cost-effective resource earlier in the planning horizon. From the 16 demand response programs evaluated in this IRP, 14 were found to be cost effective over the 24-year timeframe.
- **INTEGRATION OF DISTRIBUTED ENERGY RESOURCES**. Distributed energy resources, such as battery energy storage and rooftop and ground-mounted solar, play an important role in mitigating transmission constraints. These resources may also provide non-wire solutions to meeting specific long-term needs identified on the transmission and distribution systems.
- **SIGNIFICANT INVESTMENTS IN RENEWABLE RESOURCES**. Meeting the Clean Energy Transformation Standards will require large amounts of utility-scale renewable resources located both inside and outside of Washington state. This IRP evaluated several wind and solar locations, along with hybrid combinations such as solar plus battery storage, and wind plus battery storage. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest because it makes a higher contribution to peak capacity needs.
- **ADDITIONAL NEED FOR FLEXIBLE CAPACITY**. A large capacity deficit is created when 750 MW of coal is removed from PSE's portfolio in 2026. Renewable resources, distributed energy resources and demand response will contribute to meeting peak hour capacity need, but simple-cycle combustion turbines operated on biodiesel (a CETA complaint fuel) was found to be the most cost-effective way of maintaining system reliability. Given the limited run-time expected of these turbines, it is estimated that existing Washington state biodiesel production could meet the annual fuel supply needs.
- **FIRM RESOURCE ADEQUACY QUALIFYING CAPACITY CONTRACTS.** To reduce exposure to the increasingly supply challenged and volatile wholesale energy market, this

IRP recommends that up to 1,000 MW of PSE's Mid-C transmission should be filled with firm resource adequacy qualifying capacity contracts that meet PSE's reliability requirements for resource adequacy.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 24 years. The preferred portfolio is a diverse mix of demand- and supply-side resources that meet the projected capacity, energy and renewable resource needs described above and considers customer benefits. Incremental resource additions are shown across three time horizons along with the total resource additions for the 24-year planning horizon.

Figure 1-4: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage Hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

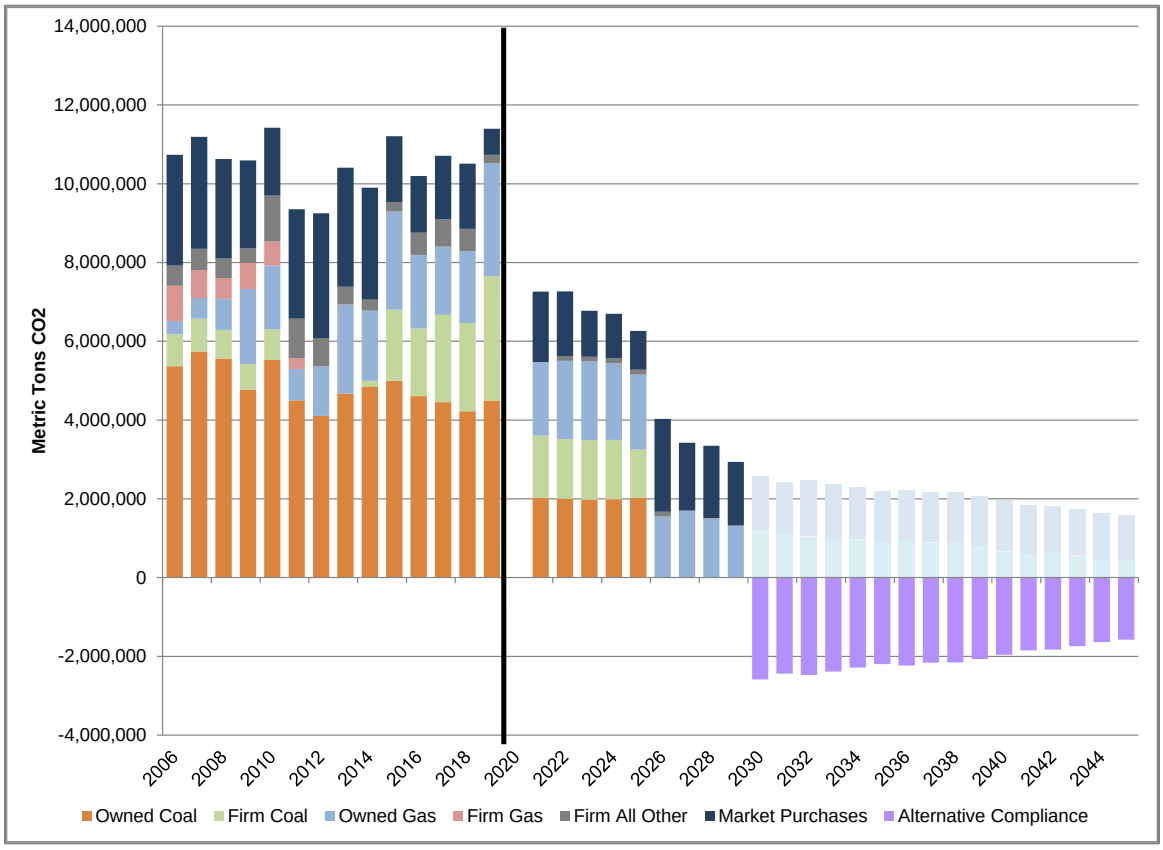
NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace with the growing demand for clean energy. Investments in the delivery system are also needed to deliver energy to PSE's customers from the edge of PSE's territory and support the integration of distributed energy resources and demand response within the delivery grid.

Greenhouse Gas Emissions

PSE's resource plan achieves significant greenhouse gas emission reductions. By 2030, PSE will drastically decrease direct greenhouse gas emissions when Colstrip Units 3 and 4 retire and the coal-transition contract with TransAlta ends, along with a significantly lower economic dispatch of existing fossil-fuel resources. A substantial drop in emissions also occurred at the end of 2019 when Colstrip Units 1 and 2 retired. In 2030, PSE will achieve a carbon neutral electric portfolio through compliance mechanisms which are not yet determined but may include additional renewable resources, energy efficiency, unbundled renewable energy credits or other energy transformation projects. Figure 1-5 shows the reduction in emissions through to the end of the planning horizon.

Figure 1-5: Reduction in PSE Greenhouse Gas Emissions



Electric Short-term Action Plan

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.

2. Equity Advisory Group

Convene and engage an Equity Advisory Group 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.

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.

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.

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.

4. ELECTRIC RESOURCE PLAN NEXT STEPS

The IRP determines the capacity, renewable and energy resource needs which set the supply-side targets for detailed planning in the Clean Energy Implementation Plan and the resource acquisition process. The CEIP will prescribe four-year targets for resources by adding near-term detail concerning resource assumptions, modeling, sensitivities and costs to PSE's 24-year IRP outlook and Clean Energy Action Plan. These costs may be derived from projects submitted through the RFP process or through other program plans, though this may be challenging in 2021 due to the compressed timeframe of the first CEIP cycle.

The formal Request for Proposal (RFP) resource acquisition processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP should also be considered when making prudent resource acquisition decisions.

CETA adds a new dynamic to resource planning in the form of evaluating and determining equitable distribution of benefits for all customers, specifically in identifying highly impacted communities and vulnerable populations. In developing the CEIP, PSE will also consider the equitable distribution of benefits to customers for the proposed projects and programs, including the equitable distribution of non-energy impacts. The IRP/CEAP includes an assessment of current conditions based on economic, health, environmental, energy security and resiliency, and other metrics, and the CEIP will use the criteria from this assessment in determining the programs and projects to implement over the next four years. The CEIP takes into consideration the mix of resources from the IRP, and applies the layer of customer benefits.

5. NATURAL GAS RESOURCE PLAN

PSE develops a separate integrated resource plan to address the needs of more than 840,000 retail natural gas sales customers. This plan is developed in accordance with the Washington Administrative Code (WAC) 480-90-238, the IRP rule for natural gas utilities. The natural gas sales analysis is described in detail in Chapter 9 and supported by several Appendices.

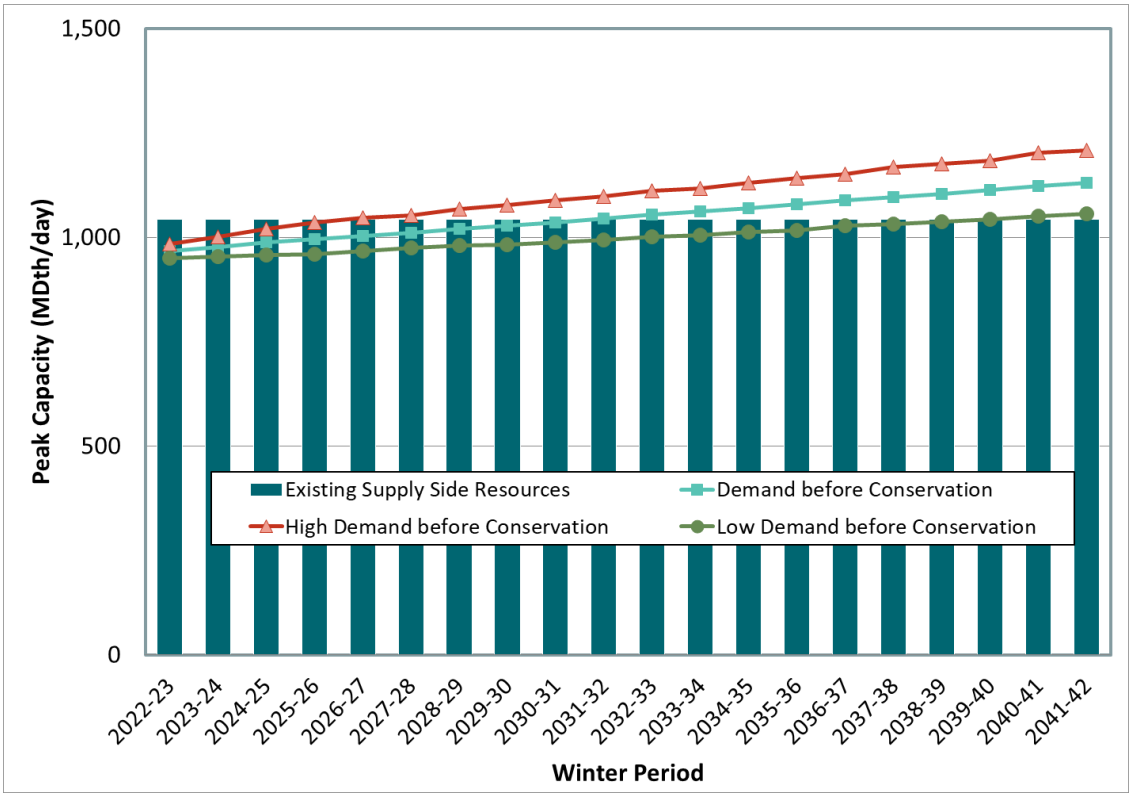
Since most of the natural gas analysis was completed prior to the 2021 Washington State legislative session, it does not include new legislation that may substantially reduce the use of natural gas in certain sectors, if enacted. While the resource plan accounts for uncertainty in demand, costs, regulations and policies, it does not account for a transformative change that could have a drastic impact on the use of natural gas. Any new legislation enacted in the 2021 legislative session that pertains to the natural gas sector will be included in the 2023 natural gas IRP.

PSE already integrates some renewable natural gas (RNG) into the delivery system to decrease carbon emissions, and PSE will continue to look for innovative ways to harvest more RNG. PSE has also begun to evaluate opportunities to partner in testing and learning how hydrogen can be blended into the natural gas system to reduce carbon emissions. This will prepare PSE to leverage the technology as supply increases, cost decreases and the technology matures.

Natural Gas Sales Resource Need

Natural gas sales resource need is driven by design peak day demand. Natural gas service must be reliable every day and the design peak demand drives the need to ensure that PSE plans for meeting firm supply on a 13-degree day. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The lines above the bars represent three different demand scenarios analyzed in this IRP, and the bars represent firm natural gas supply. The chart demonstrates PSE has a small resource need beginning in the winter of 2031-2032, where the bars are below the Mid Demand line. Demand is shown prior to conservation since the cost-effective amount of conservation is an optimized result from the natural gas analysis.

Figure 1-7: Natural Gas Sales Design Peak Day Resource Need



Natural Gas Sales Resource Additions Forecast

The natural gas resource plan is a forecast of resource additions that look like they will be cost effective in the future given what we know about resource and market trends today. It calls for increased and continued investment in conservation to meet all future peak day capacity needs. Figure 1-8 summarizes the conservation that PSE forecasts to be cost effective in the future in terms of peak day capacity and MDth per day.

Figure 1-8: Natural Gas Resource Plan Forecast

	Cumulative Reduction to Demand (MDth/day)		
	2025-2026	2030-2031	2041-2042
Conservation	21	53	107

Conservation

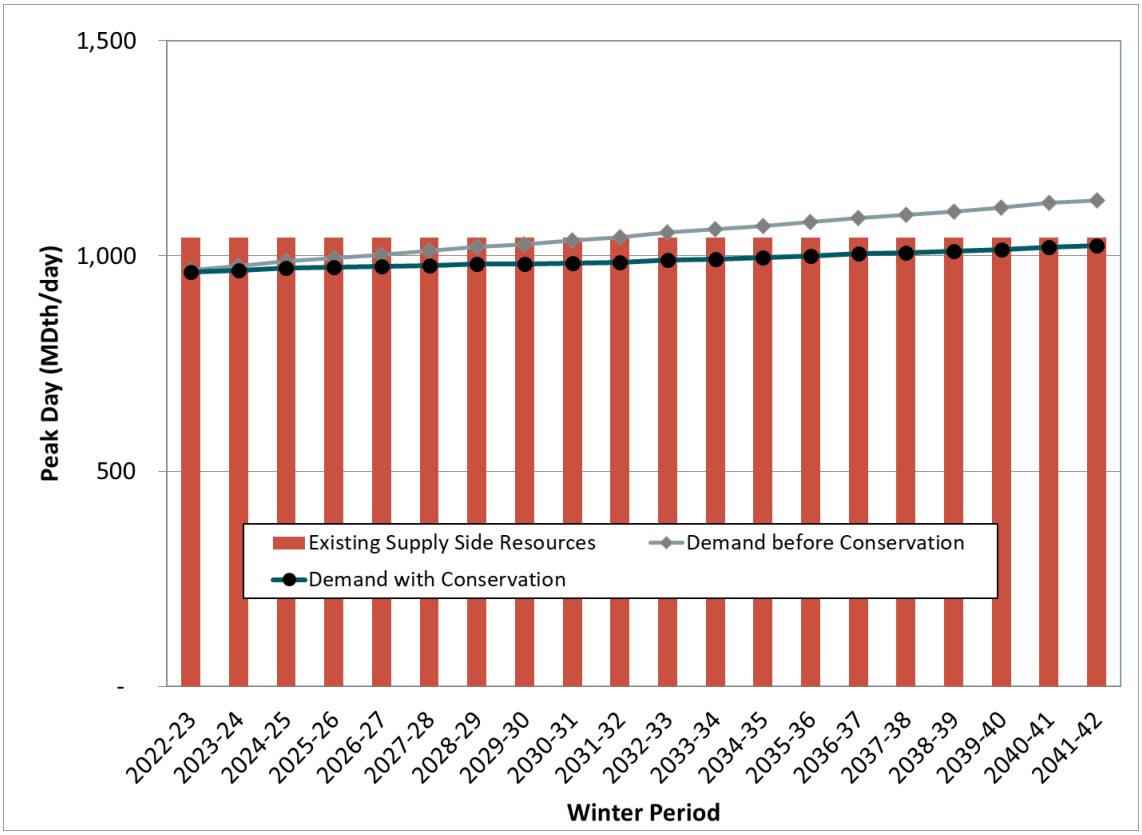
The social cost of greenhouse gases (SCGHG) has a big impact on the amount of cost-effective conservation. In 2019, the state of Washington passed new legislation that requires the inclusion of SCGHG and related upstream carbon emissions in determining cost-effective conservation. When the costs of SCGHG and upstream emissions added to natural gas prices, the resulting total cost is more three times the cost of the natural gas itself. As a result, the cost-effective amount of conservation almost doubles compared to recent energy efficiency savings and current targets, as shown in Figure 1-9.

Figure 1-9: Short-term Comparison of Natural Gas Energy Efficiency

Natural Gas Energy Efficiency	Energy Efficiency over 2-year program (MDth)
2018-2019 Actual Achievement	699
2020-2021 Target	795
2022-2023 Economic Potential in 2021 IRP	1,192

The important role that cost-effective, reliable conservation plays in moderating the need to add supply-side natural gas resources in the future can be seen in the black demand line in Figure 1-10. The bars represent the firm natural gas supply and the two lines above the bars represent natural gas demand with and without conservation.

Figure 1-10: Natural Gas Sales Resource Plan



Natural Gas Sales Short-term Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 12 MDth per day of capacity by 2024 through program savings and savings from codes and standards.

2. Renewable Natural Gas

Meet customer interest in carbon reduction programs through program development and implementation. Evaluate and develop strategies and pursue cost-effective opportunities for renewable natural gas (RNG) acquisition to support voluntary customer RNG programs and future carbon reduction.

3. 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.



2 Clean Energy Action Plan

This chapter describes the 10-year Clean Energy Action Plan for implementing the Clean Energy Transformation Standards.

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1. OVERVIEW

The Clean Energy Transformation Act (CETA) introduced the CEAP as a new aspect of the IRP designed to identify likely action over the next 10 years to meet the goals of CETA. The content of the Clean Energy Action Plan (CEAP) is specifically defined in WAC 480-100-620 subsection 12. This chapter follows the structure defined in subsection 12 and short-term actions are outlined in Chapter 1. This is the first IRP to include a CEAP, and as with any new requirement or assessment, the CEAP will evolve over time, and future IRPs will benefit from the lessons learned in this first implementation of the new planning process.

PSE is committed to achieving the goals of the Clean Energy Transformation Act (CETA) and achieving carbon neutrality by 2030 and carbon free electric energy supply by 2045, and CEAP presented here reflects these changes and goals. Specifically, the CEAP provides a 10-year outlook that refines the IRP preferred portfolio. In turn, the CEAP informs the Clean Energy Implementation Plan (CEIP), which develops specific targets, interim targets and actions over a 4-year period per RCW 19.405.060.

2. EQUITABLE TRANSITION TO CLEAN ENERGY

Assessment of Current Conditions

CETA sets out important new planning standards that require utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, PSE performed an Economic, Health and Environmental Benefits (EHEB) Assessment (or "the Assessment") to provide guidance for development of the utility's CEAP and CEIP. The purpose of the Assessment is two-fold: first, to identify highly impacted communities and vulnerable populations within PSE's service territory; and second, to measure disparate impacts to these communities using specific customer benefit indicators.

At the November 2020 IRP meeting, PSE outlined the methodology and proposed customer benefit indicators to be used in the Assessment and solicited stakeholder feedback. This feedback was incorporated into the development of the Assessment, as well as insights gained from the WUTC's December 2020 final rulemaking language and associated adoption order and the February 2021 Cumulative Impact Analysis completed by the Washington Department of Health. A full description of the methods, results and future plans for the Assessment are available in Appendix K.

PSE recognizes the importance of developing a process in which all voices are included and heard, and acknowledges that the IRP public participation process is only the first incremental step in seeking stakeholder feedback on the Assessment. Many populations and communities are not represented in the IRP public participation process. This will be an important part of the evolution of the resource planning process, and PSE anticipates additional engagement through the CEIP public participation process and in future IRP cycles.

The initial qualitative and quantitative customer benefit indicators developed through the Assessment provide a snapshot in time of the economic, health, environmental, and energy security and resiliency impacts of resource planning on highly impacted communities and vulnerable populations within PSE's service territory. Due to the timing of the IRP process and the new CETA regulations, the initial customer benefit indicators included in the CEAP should be viewed as preliminary and likely to change through public participation and input from PSE's Equity Advisory Group. The initial customer benefit indicators will be modified and evaluated over time to measure progress towards achieving an equitable distribution of benefits and reduction of burdens.

Role of the Equity Advisory Group

As part of the CEIP public participation process, PSE is establishing an Equity Advisory Group to provide specific input on the first CEIP, due in October of 2021, as well as on the implementation of that plan. In future planning cycles, the Equity Advisory Group's input will be important to incorporate starting with the planning for the IRP process. This will be an important area of learning and improvement through the entire planning cycle from the IRP through to the CEIP.

Customer Benefit Indicators

A key component to ensuring the equitable distribution of burdens and benefits in the transition to a clean energy future is to include customer benefit indicators in the preferred portfolio development process. For this IRP, due to the timing of the rulemaking and establishment of the Equity Advisory Group, PSE was only able to incorporate feedback during the IRP public process. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process.

To reflect customer benefit indicators in the development of the preferred portfolio, the customer benefit indicators were first linked to specific portfolio modeling outputs. These outputs were then combined into broader customer benefit indicator areas which provided a context for interpreting the portfolio outputs. Each portfolio from the sensitivity analyses was ranked on how well it performed in each of the customer benefit indicator areas to get an understanding of which benefits or burdens it may confer upon PSE's customers. Portfolios had to score well in several customer benefit indicator areas to be considered a preferred portfolio. The customer benefit indicator framework is described in more detail in Chapters 3 and 8.

In summary, PSE is taking several preliminary actions to ensure that all customers benefit from the transition to clean energy:

1. Establishing the Equity Advisory Group
2. Developing a public participation plan for the CEIP to obtain input on equitable distribution of benefit and burdens
3. Refining customer benefit indicators and metrics with the EAG and the CEIP public participation process
4. Updating the Customer Benefits Analysis to incorporate the customer benefit indicators and related metrics in the CEIP and future IRPs

3. 10-YEAR CLEAN RESOURCE ADDITIONS

10-Year Clean Resource Summary

In alignment with the IRP 24-year outlook, Figure 2-1 below summarizes the 10-year outlook for the resource mix in the preferred portfolio. The customer benefit indicators informed the final selection of resources while also ensuring the preferred portfolio met PSE's peak capacity, energy and renewable needs and addressed market risk.

Figure 2-1: 10-year Annual Resource Additions Preferred Portfolio

Resource Type	Incremental Nameplate Resource Additions (MW)										Total (MW)
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Distributed Energy Resources											
Demand-side Resources											
Energy Efficiency	36	39	41	42	44	47	50	50	54	56	458
Distributed Generation – Solar PV	0.2	0.4	0.7	1.2	2.1	3.6	6.1	10	16	18	58
Distribution Efficiency	1.2	0.3	0.7	1.8	1.2	1.3	1.3	1.3	1.3	1.3	12
Codes & Standards	37	24	19	12	15	14	25	13	4	6	169
Total Demand-side Resources	74	64	61	57	63	66	82	75	75	81	696
Battery Energy Storage	-	-	-	25	25	25	25	25	50	25	200
Solar - ground and rooftop	-	-	-	80	30	30	30	30	30	30	260
Demand Response	-	5	6	18	27	34	40	27	26	13	196
DSP Non-wire Alternatives	3	6	9	4	3	5	6	5	4	4	50
Total Distributed Energy Resources	78	75	75	184	148	160	183	161	185	153	1,402
Renewable Resources											
Wind	-	-	-	400	200	400	-	200	200	100	1,500
Solar	-	-	-	-	-	100	-	100	198	0	398
Total Renewable Resources	-	-	-	400	200	500	-	300	398	100	1,898
Peaking Capacity with Biodiesel	-	-	-	-	255	-	-	-	-	-	255
Firm Resource Adequacy Qualifying Capacity Contracts	-	185	187	202	202	203	-	-	-	-	979

Conservation Potential Assessment

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the IRP portfolio analysis. Then the portfolio analysis determines the maximum amount of energy savings that can potentially be captured without raising the overall electric portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio. The full assessment is included in Appendix E.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP. While the IRP evaluates demand-side resources through the CPA process, the CEIP will establish the specific targets for renewable energy, energy efficiency and demand response, and may evaluate programs aligned with those targets.

- **ENERGY EFFICIENCY MEASURES.** This includes a wide variety of measures that result in a smaller amount of energy being 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 upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. The achievable technical potential for demand response was assessed through the CPA, and the cost-effective demand response programs identified in this IRP are described in a separate section below.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer's load on customer's side of the utility meter. The CPA identifies combined heat and power (CHP) and customer-owned rooftop solar as distributed generation. Other distributed energy resources are also evaluated in this IRP and described in a separate section below.
- **DISTRIBUTION EFFICIENCY (DE**). Distribution efficiency addresses conservation voltage reduction (CVR), which is the practice of reducing the voltage on distribution circuits to reduce energy consumption, since many appliances and motors can perform properly while consuming less energy. Phase balancing is required for CVR to eliminate total current flow energy losses.
- **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. Only those in place at the time of the CPA study are included.

Figure 2-2 shows the achievable technical potential of demand-side resource savings in PSE's service territory. The year 2031 savings represent the 10-year potential starting in 2022.

Figure 2-2: 10-year Achievable Technical Potential Demand Side Resource Savings

Demand-Side Resources	Nameplate 2031	Energy Savings 2031	Peak Capacity Savings 2031
Energy Efficiency	458 MW	263 aMW	458 MW
Distributed Generation: Solar PV	58 MW	7 aMW	0 MW
Distribution Efficiency	12 MW	11 aMW	12 MW
Codes and Standards	169 MW	93 aMW	177 MW
Total Achievable Technical Potential	696 MW	374 aMW	646 MW

NOTES
1. Demand response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency.
3. Given the nature of the IRP, assumptions for the models need to be set months before the IRP is finalized. This is simply of forecast of best known information at the time. Some of these forecast may have changed since the IRP inputs were finalized.

The IRP analysis evaluates the amount of demand-side resources (conservation) that is cost effective to meet the portfolio's capacity and energy needs, optimizing lowest cost and considering both distributed and centralized resources. The final analysis indicates that although current market power prices are low, accelerating the acquisition of DSR continues to be a least-cost strategy to meet renewable requirements. CETA renewable requirements result in significant increases in avoided cost, and this impacts the amount of cost-effective DSR. The large amounts of renewable resources needed to meet CETA move higher cost demand-side resources into the portfolio because conservation reduces load, thereby reducing the amount of renewable resources needed to meet requirements. Figure 2-3 shows the cost-effective amount of demand-side resources identified in the IRP by category (energy efficiency, customer solar PV forecast, distribution efficiency and codes and standards).

Figure 2-3: Cost-effective Demand-side Resources Incremental Nameplate Additions

Demand-Side Resources	Incremental Nameplate Additions		10-year Total
	2022-2025	2026-2031	
Energy Efficiency	157 MW	301 MW	458 MW
Distributed Generation: Solar PV	2 MW	56 MW	58 MW
Distribution Efficiency	4 MW	8 MW	12 MW
Codes and Standards	92 MW	77 MW	169 MW
Total Demand-side Resources	256 MW	440 MW	696 MW

NOTES
1. Demand Response is not included in the cost-effective DSR. It is included separately below.
2. Customer solar PV is the only distributed resource modeled as a separate measure, CHP is included in energy efficiency. Additional distributed energy resources were evaluated in this IRP and are described below.

Resource Adequacy

PSE has established a 5 percent loss of load probability (LOLP) resource adequacy metric to assess physical resource adequacy risk. LOLP measures the *likelihood* of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s). Therefore, the likelihood of capacity being lower than the load, occurring anytime in the year, cannot exceed 5 percent.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility and dependent on load shapes and supply availability, so it is hard to compare the ELCC of PSE's resources with those of other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and the availability of supply-side resources. A full description of the peak capacity and ELCC values is in Chapter 7.

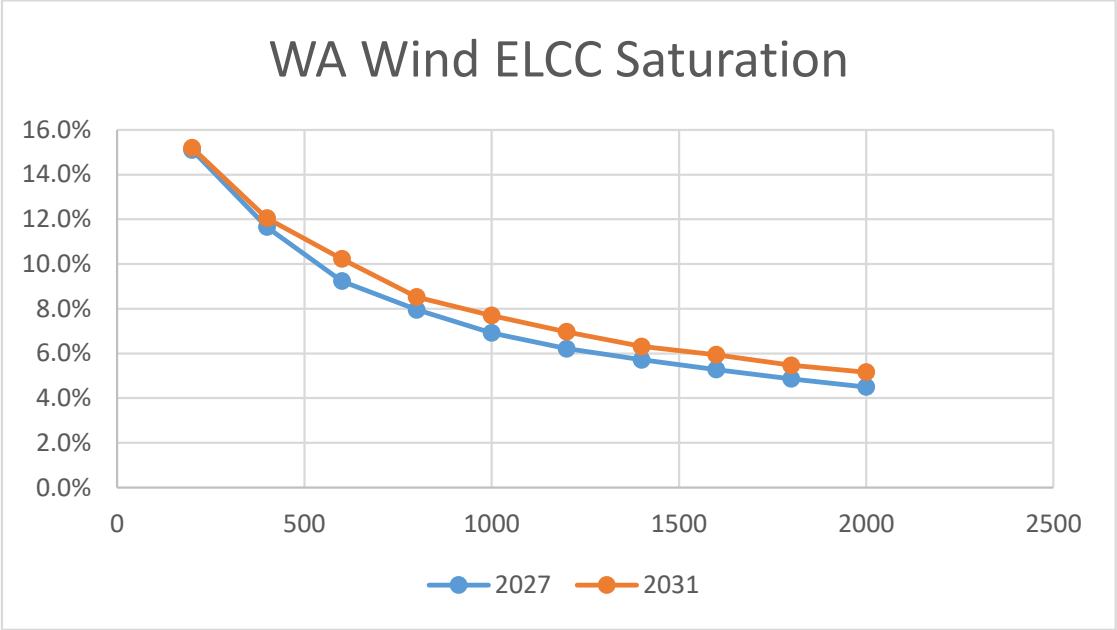
Figure 2-4 shows the estimated peak capacity credit or ELCC of the wind and solar resources included in this IRP. The order in which the existing and prospective projects were added in the model follows the timeline of when these projects are acquired or about to be acquired. The concept of resource saturation is also important to the ELCC calculation. Each incremental resource added in the same geographical area provides less effective peak capacity because it provides more of the same resource profile rather than increasing the diversity of the resource profile. The ELCC calculation for the first 100 MW of the resource is shown below in Figure 2-4, and the full saturation curve for up to 2,000 MW of Washington wind and solar is shown in Figure 2-5.

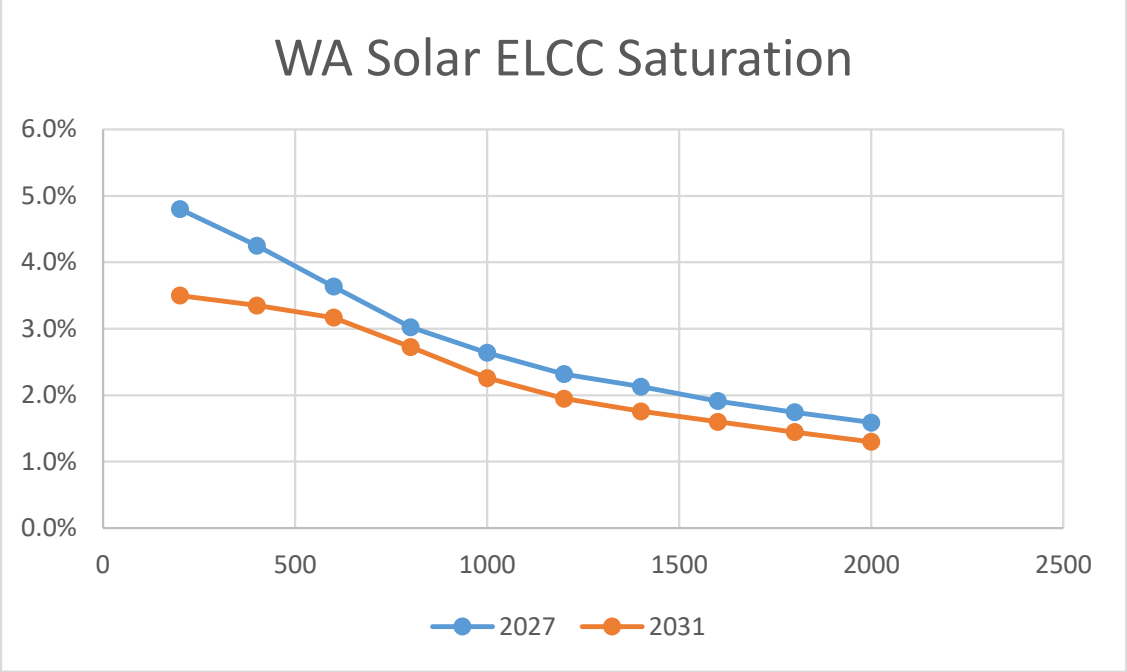
Figure 2-4: Peak Capacity Credit for Wind and Solar Resources

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar	100	4.0%	3.6%
Generic WA West Solar – Utility scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

ELCC SATURATION CURVES. The table above shows the peak capacity credit for the first 100 MW of installed nameplate capacity for Washington state wind and solar. Below, Figure 2-5 plots the peak capacity credit for the next 200 MW and then the next 200 MW after that and so on, showing how the peak capacity credit decreases as more wind or solar is added in the same region. Wind or solar nameplate capacity is shown in MW on the horizontal axis, and peak capacity credit as a percent of nameplate capacity is shown on the vertical axis.

Figure 2-5: Saturation curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak capacity credit of two types of batteries were modeled as well as pumped storage hydro. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. Figure 2-6 shows the peak capacity credit of the types of storage resources modeled in the IRP. The peak capacity credit for battery storage is low because batteries are relatively short-duration resources. Unlike generating resources, battery storage resources have to recharge; therefore, when long-duration needs for energy occur as in winter peaks, batteries provide little contribution compared to generating resources. Longer duration storage resources provide higher peak capacity credits.

Figure 2-6: Peak Capacity Credit for Energy Storage

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

DEMAND RESPONSE CAPACITY CREDIT. The estimated peak capacity credit of demand response is shown in Figure 2-7.

Figure 2-7: Peak Capacity Credit for Demand Response

DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Wholesale Electric Market Risk

The wholesale electric market has changed significantly in recent years and is now experiencing tighter supply and increasing price volatility. As a result, regional power suppliers, including PSE, are making changes to how they plan with regard to resource adequacy. Addressing resource adequacy issues on a regional basis, rather than utility-by-utility, has the potential to increase reliability for all providers in the region, and as a result, numerous regional entities, including PSE, are collectively developing a regional resource adequacy program. At this time, the program has not been included in the IRP analysis because sufficient details are not yet known. However, it is important that PSE takes appropriate steps in its resource planning to allow for future participation in a regional resource adequacy program once established.

For this IRP, PSE conducted a market risk assessment to evaluate the use of its 1,500 MW of firm transmission to the Mid-Columbia market hub with short-term energy purchase agreements. . The assessment resulted in a recommendation that part of PSE's Mid-C transmission be dedicated to firm resource adequacy qualifying capacity contracts to ensure reliable service. The recommendation includes limiting the amount of real-time, day-ahead and term market purchases and replacing a portion of those energy contracts with firm resource adequacy qualifying capacity contractual arrangements to meet PSE's resource adequacy requirements as well as those of a future regional resource adequacy program. PSE has a strong preference for clean resources and contractual arrangements.

Ensuring Resource Adequacy

PSE must meet capacity need over the planning horizon with firm capacity resources or contractual arrangements to maintain reliability. All resources, including renewable resources, distributed energy resources and demand response, contribute to meeting the capacity needs of PSE's customers, but they make different kinds of contributions. This IRP determined that the limited-run use of simple-cycle combustion turbines (peakers) operated on biodiesel (a CETA complaint fuel) is the most cost effective means of ensuring resource adequacy. Chapters 3, 5 and 8 describe the numerous clean resource combinations PSE analyzed as an alternative to the biodiesel peaker solution and the significant increases in portfolio costs that resulted. Figure 2-8 summarizes the capacity needed to meet reliability requirements across the first ten years of the planning horizon. The recommended approach from the market risk assessment is also included and shown as firm resource adequacy qualifying capacity contracts.

Figure 2-8: Capacity Additions to meet Reliability

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Peaking Capacity with Biodiesel	0 MW	255 MW	255 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	979 MW

Demand Response

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times requesting them to reduce their energy use. Some program types require action by the customer, others can be largely automated. For example, an automated program might warm a customer's home or building earlier than usual with no action required. In a program that requires customer action, a wastewater plant may be asked to curtail pumping during certain peak energy need hours if they can operationally do so. Because customers can always opt out of an event, demand response programs include some risk. If PSE is relying on a certain amount of load reduction from demand response to handle a peak event but customers opt out, then PSE must use generating resources to fill the customer's needs.

Demand response programs modeled for this IRP are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral Demand Response

Figure 2-9 lists the estimated achievable technical potential for all winter demand response programs modeled for the residential, commercial and industrial sectors in this IRP. The table shows the achievable potential of each demand response program in MW and the percentage of winter peak need it fills to illustrate the total potential impact of demand response on system peak. The winter percent of system peak load was calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019. The total demand response nameplate achievable potential is 228 MW. The peak capacity credit of demand response programs is shown above in Figure 2-7. Further details about demand response programs modeled in this IRP can be found in Appendix D and E. The program costs shown include a

transmission and distribution (T&D) benefit that reflects the value of the program to the distribution system non-wires alternatives. Some programs have a negative cost because the benefits they deliver are greater than their cost to the system.

Figure 2-9: Demand Response Achievable Potential and Levelized Cost by Product Option

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-Auto DR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

This IRP evaluated 16 different demand response programs and 14 of those were found to be cost effective. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate capacity by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers; by 2031, this grows to 196 MW. Figure 2-9 summarizes the cost-effective demand response nameplate capacity.

Figure 2-9: Cost-effective Demand Response Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Demand Response	29 MW	167 MW	196 MW

Renewable Resources

For this IRP, wind was modeled in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and off the coast of Washington. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States.

Energy storage resources were modeled separately and in combination with the renewable resources. Two battery storage technology systems were analyzed, lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. Pumped storage hydro resources were also analyzed. These are generally large, on the order of 250 to 3,000 MW, and the analysis assumes PSE would split the output of a pumped storage hydro project with other interested parties. PSE analyzed an 8-hour pumped storage hydro resource and modeled the project in 25 MW increments. In addition to standalone generation and energy storage resources, PSE modeled hybrid resources that combine two or more resources at the same location to take advantage of synergies between the resources. Three types of hybrid resources were modeled: eastern Washington solar plus 2-hour lithium-ion battery, eastern Washington wind plus 2-hour lithium-ion battery and Montana wind plus pumped storage hydro.

This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources from the Pacific Northwest region may be limited. The timing of renewable resource additions is driven by CETA renewable requirements and is shown in Figure 2-10 below. Hybrid resources were shown to be cost effective later in the planning horizon so they are not shown in the first ten years.

Figure 2-10: Renewable Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Wind Resources	400 MW	1,100 MW	1,500 MW
Solar Resources	-	398 MW	398 MW
Total Renewable Resources	400 MW	1,498 MW	1,898 MW

Distributed Energy Resources

While the adoption of distributed energy resources (DER) is still low in PSE's service territory, about 1 percent of PSE customers are participating in net-metered solar, with an installed capacity of approximately 85 MW. As DER technology evolves and prices decline, customer adoption will likely increase. DERs will play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs. To accomplish this, PSE will file a draft targeted RFP with the WUTC no later than November 15, 2021 for both distributed energy resources and demand response resources, consistent with Order 05 in Docket UE-200413.

In this IRP, PSE specifically included several different types of distributed energy resources. In addition, demand response, which is considered a distributed energy resource, was also modeled in this IRP as discussed above.

BATTERY ENERGY STORAGE. Two distributed battery storage technology systems were analyzed: lithium-ion and flow technology. These battery storage systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations or on the distribution system, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries and 4-hour and 6-hour flow battery systems.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop and ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington.

NON-WIRES ALTERNATIVES. The role of DERs in meeting delivery system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission

and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs, and they can be deployed across both the transmission and distribution systems, providing some flexibility in how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

Figure 2-11 shows the battery energy storage, solar and non-wire alternatives distributed energy resources.

Figure 2-11: Distributed Energy Resources Incremental Nameplate Capacity

Resource Type	Incremental Resource Additions		10-year Total
	2022-2025	2026-2031	
Battery Energy Storage	25 MW	175 MW	200 MW
Solar	80 MW	180 MW	260 MW
Non-Wire Alternatives	22 MW	28 MW	50 MW
Total Distributed Energy Resources	127 MW	383 MW	510 MW

4. DELIVERABILITY OF RESOURCES

PSE will work to optimize use of its existing regional transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, the Pacific Northwest transmission system may need significant expansion, optimization and possible upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California. The specific opportunities for expanding transmission capabilities and regional efforts to coordinate transmission planning and investment are described in detail in Appendix J. The 10-year delivery system plan is described in Appendix M.

Investments in the delivery system are needed to deliver energy to PSE's customers from the edge of PSE's territory and to support DERs within the delivery grid. The delivery system 10-year plan described in Appendix M identifies work that is needed to ensure safe, reliable, resilient, smart and flexible energy delivery to customers, irrespective of resource fuel source. These include specific upgrades to the transmission system to meet NERC compliance requirements and other evolving regulations related to DER integration and markets and to the distribution system to enable higher DER penetration. Specific delivery system investments will become known when energy resources, whether centralized or DERs, begin siting through the established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost for interconnection and increase the number of viable locations. Proactive investments in grid modernization are also critical to support the clean energy transition and maximize benefits. The key investment areas are summarized below.

Visibility, Analysis, and Control

Data availability, integrity and granularity are critical aspects to planning for and operating DERs. Through PSE's ongoing investment in Advanced Metering Infrastructure (AMI) and SCADA at distribution substations, PSE will have new data and visibility that can be utilized for delivery system planning, customer program planning and operational analytics. AMI is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. AMI meters will serve to provide significant enhancements to the types and granularity of data PSE can collect to proactively plan for growth, integrate new technologies, offer services to customers, respond more quickly to system needs and operate the system safely. PSE is currently implementing an Advanced Distribution Management System (ADMS). ADMS is a computer-based, integrated platform that provides the tools to monitor and control our distribution network in real time. The implementation of ADMS will ultimately lead to advanced operational capabilities for DERs including an integrated Distributed Energy Resource Management System (DERMS). Prior to implementation of a fully integrated DERMS, PSE anticipates the need for a virtual power plant (VPP). Virtual power plants

forecast and aggregate different types of DERs in order to coordinate dispatch to meet system resource needs. VPPs can aggregate DERs including demand response, EV charging management, CHP, solar PV (smart inverters) and distributed storage. Some VPPs can also manage alternative pricing programs such as Peak Time Rebates. In order to realize the dispatchable capacity benefits of the DER additions expected over the next 5 years, PSE needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. needs a VPP to manage DER customer acquisition, forecasting, dispatch and settlement. PSE will develop the technical and operational requirements for a VPP platform in mid-2021. In addition to AMI and ADMS, SCADA provides real-time visibility and remote control of distribution equipment to reduce duration of outages, improve operational flexibility and enhance overall reliability of the distribution system.

PSE also recognizes the importance of maintaining and augmenting the data that we already have, particularly the asset data within our Geographic Information System (GIS). PSE is working to evolve GIS processes so that changes in the field can be quickly incorporated and so that data such as DER asset information is collected and displayed. GIS connects with many enterprise systems, and GIS data will be increasingly central to the ability to plan for and operate DERs. Finally, data analytics programs will support optimization of customer service and system operations including predicting asset replacement needs before failure as DERs are added to the grid.

PSE also plans to implement a geospatial load forecasting tool that includes DER forecasting capabilities as well as end-use forecasting information that supports our energy efficiency and demand response programs. With this tool we can understand not only the anticipated growth of DERs, but also the specific feeder locations. This will enable proactive system investments and potentially uncover targeted demand-side management options and support non-wires alternatives. PSE will continue to enhance its modeling tools and capabilities to ensure grid stability.

Reliability and Resiliency

To avoid reactive investments due to unanticipated DER adoption and integration and in addition to the work already described, PSE will pursue targeted, proactive asset management and system upgrades to enable DER integration and transportation electrification through ensuring a healthy system, managing load and DERs, and ensuring reliable operation. Grid modernization investments will improve the reliability of PSE systems, improve their ability to withstand and recover from extreme events, and enable smart and flexible grid capabilities. Ongoing and site-specific asset investments are needed such as pole replacement, tree-wire conductor and cable remediation programmatic transformer replacements as DERs and electric vehicles propagate, and substation and circuit enhancements that ensure or expand DER effectiveness.
Managing increasing loads will be intentional with advanced capabilities such as Volt-Var Optimization (VVO) and enabling faster system outage restoration through use of Fault Location, Isolation Service Restoration (FLISR), all enabled through the ADMS platform and additional investments in reclosers, switches, voltage regulators, capacitors banks and network communications infrastructure. FLISR will support grid reliability to enable battery energy storage charging and transportation electrification. VVO will manage voltage and reactive power as loads shift due to DER implementation.

PSE will also pursue energy security and resiliency investments such as microgrids or infrastructure hardening where specific locations require increased resilience. These locations could include highly impacted communities, transportation hubs, emergency shelters and areas at risk for isolation during significant weather events or wildfires.

DER Integration Processes

In addition to the enabling technologies, analytical capabilities and system component upgrades, PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for both customers and developers by prescreening applications. Additional customer tools, such as modifications to billing systems and program administration and design, may be needed as PSE's operating model moves from traditional one-way power flow to two-way energy flow and delivery. PSE continues to integrate non-wire alternative analysis in developing investment plans to meet various energy needs of our customers.

Security, Cybersecurity and Privacy

While pursuing our grid modernization strategy, PSE will continue to put a strong focus on cyber-security. PSE applies the same level of due diligence across the enterprise to ensure risks are consistently addressed and mitigated in alignment with the rapidly changing security landscape. PSE utilizes a variety of industry standards to measure maturity as each standard approaches security from a different perspective. As critical infrastructure technology becomes more complex, it is even more crucial for PSE to adapt and mature cyber-security practices and programs allowing the business to take advantage of new technical opportunities such as Internet of Things (IoT) devices. In addition, we continue to foster strong working relationships with technology vendors to ensure their approach to cyber-security matches PSE's expectations and needs.

Backbone Infrastructure Projects

Finally, PSE will continue to upgrade its local transmission system in order to meet NERC compliance requirements and evolving regulations related to DER integration and markets and meet peak demand reliably. PSE will deploy identified, project-specific non-wires solutions to support the near-term integration of DERs and continue to validate the DER forecast to realize predicted solutions to meet resource needs.

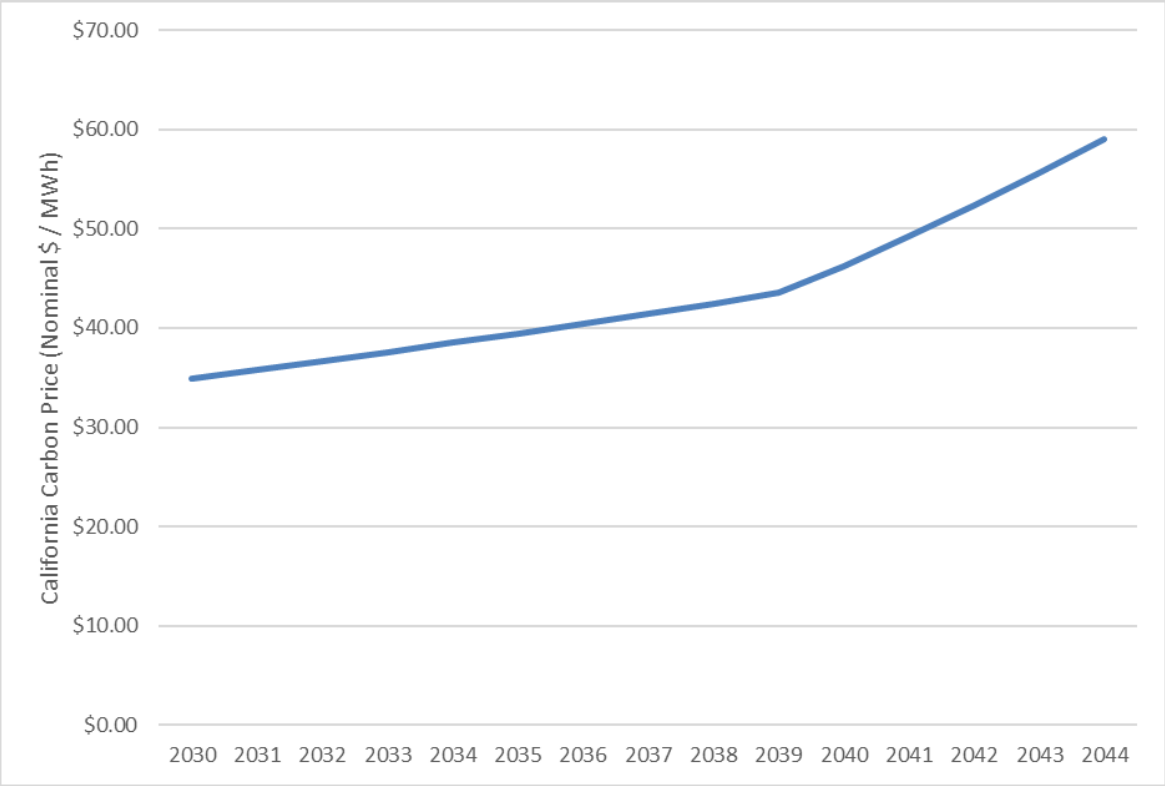
5. ALTERNATIVE COMPLIANCE OPTIONS

Under CETA, up to 20 percent of the 2030 greenhouse gas neutral standard can be met with an alternative compliance option. These alternative compliance options can be used beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty
- purchasing unbundled renewable energy credits
- investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission

In this IRP, PSE evaluated two alternative compliance options. For the first option, PSE assumed that unbundled renewable energy credits would be purchased for 20 percent of load not met by renewable generation starting in 2030 and decreasing linearly to zero in 2045. Because there is no a transparent forecast of the future price of unbundled renewable energy credits, PSE used the California carbon price as a proxy, as this may align with the requirement for greenhouse gas neutral electricity. The forecasted prices start at over $34 per MWh in 2030 and increase to $59 per MWh in 2044 as shown on Figure 2-12. The costs are included in all the portfolios as part of meeting the 2030 standard and in the preferred portfolio.

Figure 2-12: California Carbon Price Forecast (nominal $ per MWh)



In addition to using carbon prices as a proxy price for unbundled renewable energy credits, PSE also wanted to understand the impact of meeting the 20 percent of load with renewable resources such that 100 percent of PSE's load is met with renewable resources by 2030. PSE modeled two ways of meeting this requirement; with battery energy storage and with pumped storage hydro. The total 24-year NPV of this compliance option is $32 billion with batteries and $66 billion with pumped storage hydro. The costs of these two portfolios are between $16 billion and $50 billion higher than the preferred portfolio. Chapter 8 describes these portfolios in detail in Sensitivity N.

Actual compliance may be met through other mechanisms that are still under development and will be determined in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. PSE will analyze these mechanisms as the Department of Ecology develops guidance on methods for assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

6. SOCIAL COST OF GREENHOUSE GASES

The social cost of greenhouse gases (SCGHG) is applied as a cost adder in the development of the electric price forecast and in the portfolio modeling process when considering resource additions. The SCGHG is not included in the final dispatch of resources because it is not a direct cost paid by customers. CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resources options. The SCGHG cost adder is included in planning decisions as part of the fixed operations and maintenance costs of that resource, but not in the actual cost and dispatch of any resource. A SCGHG adder is also applied to the unspecified market purchases.

The SCGHG in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from $69 per ton in 2020 to $189 per ton in 2045. Further details can be found in Chapter 5.



3 Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and natural gas resource plans and demonstrates how the electric resource plan meets the clean energy transformation standards.

3 Resource Plan Decisions

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1. OVERVIEW

The preferred portfolio is the outcome of robust IRP analyses developed with stakeholder input. It meets the requirements of the Clean Energy Transformation Act and is informed by deterministic portfolio analysis, stochastic portfolio analysis and the Customer Benefit Analysis. The preferred portfolio is a new requirement in the IRP, and this first preferred portfolio marks a significant shift in PSE's resource direction since the 2017 IRP. The preferred portfolio focuses on clean resources to meet CETA requirements, as well as increases in distributed energy resources.

To support the portfolio analysis to arrive at the preferred portfolio, three distinct types of analysis are used. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future. The stochastic analysis assesses the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages. The Customer Benefit Analysis incorporates the equitable distribution of burdens and benefits into the resource planning process. All three of these analytic methods are used to identify and evaluate the preferred portfolio.

Further information on the analyses discussed here can be found in Chapters 5, 6, 7, 8, 9 and the Appendices.

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 3-1 summarizes the forecast of resource additions to the preferred electric portfolio. This portfolio prioritizes cost-effective, reliable conservation and demand response, and distributed and centralized renewable and non-emitting resources at the lowest reasonable cost to our customers. It reduces direct PSE emissions by more than 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments and projected compliance options. While implementing this highly decarbonized portfolio, the portfolio maintains the reliability required with the addition of flexibility capacity starting in 2026.

Figure 3-1: Electric Preferred Portfolio,

Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

Compliance with Clean Energy Transformation Standards

Electric utilities must meet the clean energy standards set by CETA at the lowest reasonable cost. In addition, safety, reliability and the balancing of the electric system must be protected, and electric utilities must ensure that all customers are benefiting from the transition to clean energy.

The clean energy transformation standards state that:

1. On or before December 31, 2025, each utility must eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers;
2. By January 1, 2030, each utility must ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral; and
3. By January 1, 2045, each utility must ensure that non-emitting electric generation and electricity from renewable resources supply 100 percent of all retail sales of electricity to Washington electric customers.

CETA also contains an incremental cost of compliance mechanism that can be used for compliance purposes. In this IRP, PSE does not rely on the incremental cost of compliance mechanism to comply with CETA. All clean energy transformation standards are met with new resources.

MEETING CETA 2025 REQUIREMENTS. Colstrip is removed from PSE's electric supply portfolio by the end of 2025 and replaced with a combination of renewable resources, conservation, demand response, battery energy storage and a simple-cycle combustion turbines (a frame peaker) operated on biodiesel. Biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests is a CETA-compliant renewable resource; all new peaking resources modeled in this analysis are operated with biodiesel fuel, and it is the only fuel used for new peaking resources in the preferred portfolio. The October 2020 U.S. Department of Energy report on alternative fuel prices calculated the price of B99/B100 biodiesel for the west coast at $3.88/gallon.[1] PSE currently operates several peaking plants that can run a back-up fuel (distillate fuel oil) and therefore has experience with storage and transportation for diesel fuels. Given the limited run-time expected of the new turbines, the IRP analysis estimates that existing Washington state biodiesel production could meet new peaking resource fuel supply needs.

1 / Clean Cities Alternative Fuel Price Report, October 2020 (energy.gov)

MEETING CETA 2030 REQUIREMENTS. The preferred portfolio achieves 100 percent greenhouse gas neutrality by 2030 through coal plant retirements in 2025 and by replacing most of the energy produced by existing natural gas plants with renewable resources and projected alternative compliance options. The preferred portfolio meets 80 percent of sales with renewable resources by 2030 and the remaining 20 percent with clean investments and projected compliance options. The projected 20 percent alternative compliance is included as an additional cost starting in 2030.

Figure 3-2 shows the emissions by resource type for the preferred portfolio. There is a direct relationship between emissions and the dispatch of thermal resources. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will further decline with a projected lower economic dispatch of thermal resources and the exit of Colstrip 3 & 4 and Centralia from the PSE portfolio. The retirement of resources and forecasted drop in dispatch decreases the total portfolio emissions by more than 70 percent from 2019 to 2029. Through projected compliance mechanisms, the portfolio achieves carbon neutrality starting in 2030 through to 2045.

PSE also evaluated the costs associated with achieving 100 percent renewable resources by 2030. Reducing emissions and even achieving a 100 percent renewable portfolio by 2030 is possible with existing technologies, but the cost to do so is high. The massive investment in energy storage required to replace thermal resources results in portfolio costs that are $16 billion to $50 billion higher than the preferred portfolio.

Figure 3-2: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions

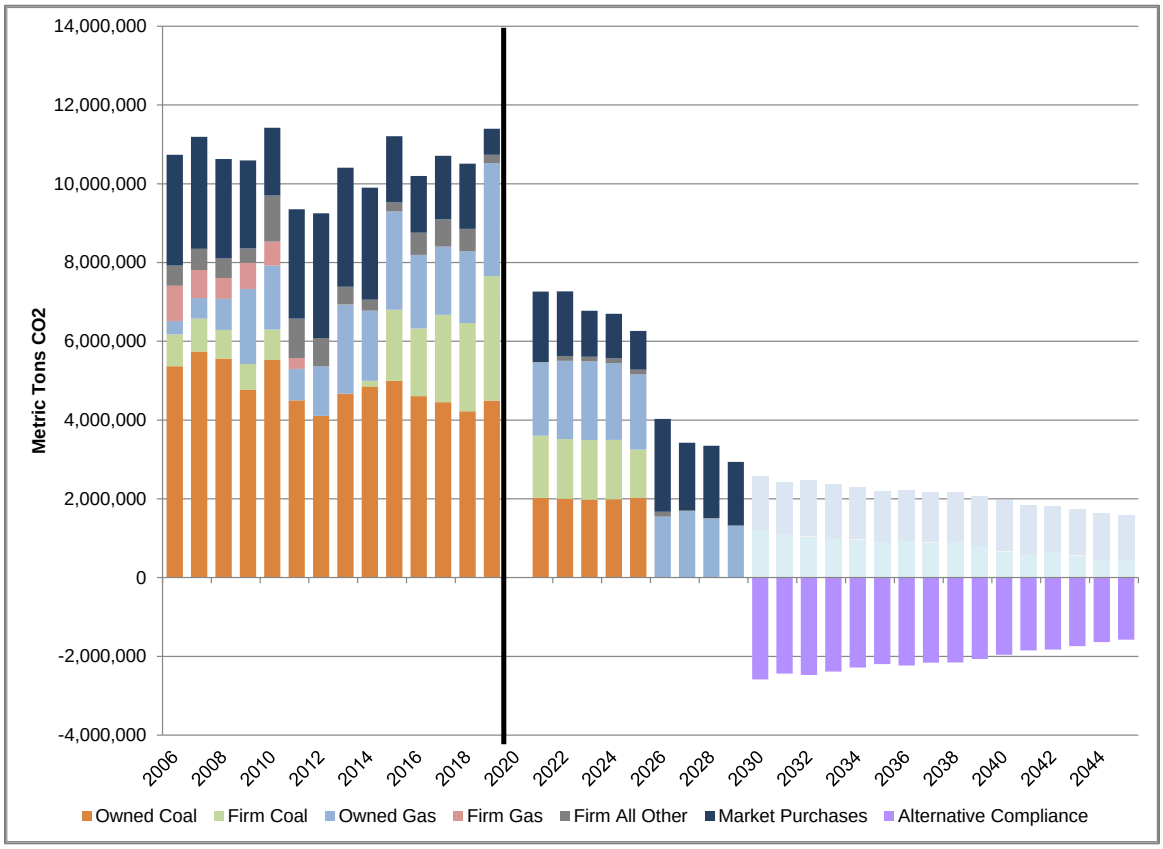
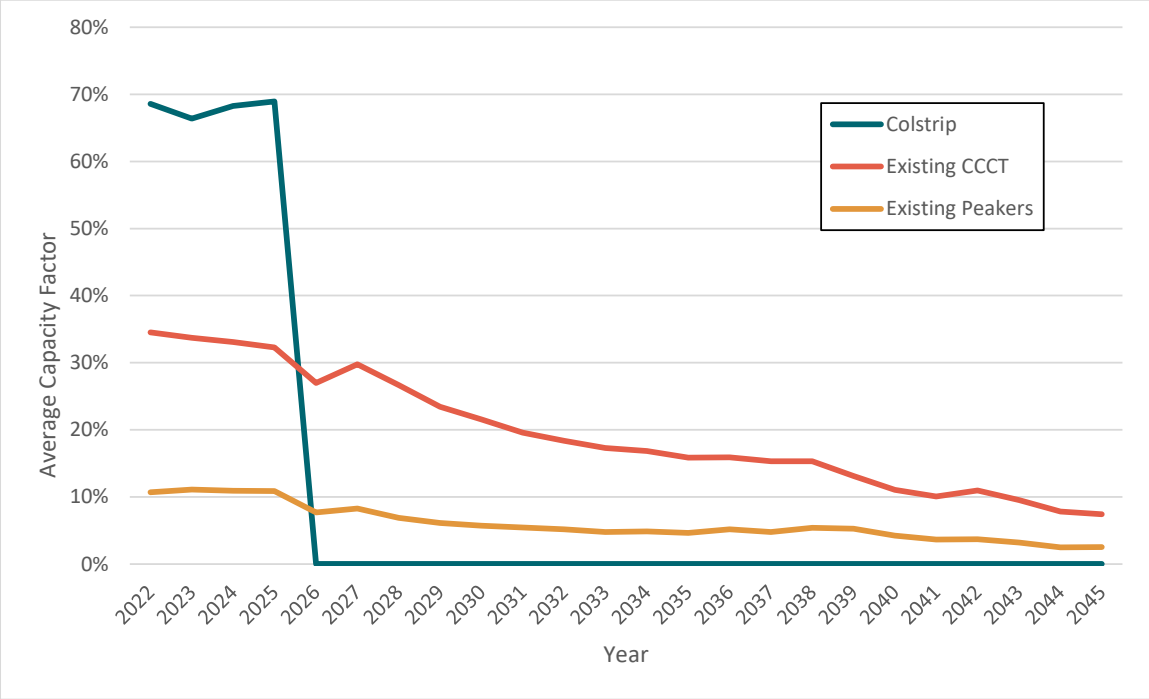


Figure 3-3 shows the annual percentage of time that the thermal resources dispatch, known as the capacity factor. Historically Colstrip dispatched around 85 percent to 90 percent of the time, but with increased costs, its dispatch has dropped below 70 percent. The existing natural gas CCCT plants average around a 35 percent capacity factor, with the highest dispatching units projected to run 60 percent to 70 of the time at the beginning of the time horizon. As new renewable resources are added to the portfolio, the projected dispatch of the existing natural gas CCCT decreases to around 7 percent by the end of the planning horizon. Existing natural gas peaking plants have always had low dispatch, since they are mostly used to maintain reliability during times of peak demand. The dispatch of the new peaking plants has an annual average capacity factor of 10 percent at the beginning of the planning horizon that drops to around 2 percent by the end of the planning horizon.

Figure 3-3: Projected Annual Thermal Resources Dispatch for PSE Existing Resources



MEETING CETA 2045 REQUIREMENTS. By 2045, 100 percent of retail sales is met by non-emitting and renewable resources. Retail sales is the total amount of energy delivered to customers. The preferred portfolio reduces the amount of energy delivered to customers by adding over 6.5 million MWh of new demand-side resources that include conservation and customer programs, and by adding almost 14.9 million MWh of new renewable resources. After demand-side resources and customer programs, PSE needs an additional 13.5 million MWh of non-emitting and renewable resources by 2045 to reach 100 percent of retail sales. The new wind, solar, biomass and hybrid resources in the preferred portfolio add 14.9 million MWh of non-emitting and renewable resources, making the preferred portfolio compliant with the 2045 CETA goal. Figure 3-4 breaks down how the preferred portfolio meets the 100 percent non-emitting and renewable resource requirement.

Figure 3-4: Calculation of 2021 IRP Preferred Portfolio CETA Compliance for 2045

	MWh
2045 Estimated Sales before Conservation[1]	29,051,232
Demand-side Resources	(6,565,285)
Line Losses	(1,529,044)
Load Reducing Customer Programs & PURPA	(1,493,096)
Sales Net of Conservation and Customer Programs	19,463,807
Existing Non-emitting and Renewable Resources[2]	(5,904,043)
Need for New Renewable/Non-emitting Resources	13,559,765
New Non-emitting and Renewable Resources	
Wind	10,767,902
Solar – Utility-scale	1,461,402
Solar – distributed ground and rooftop	963,861
Biomass	778,334
Hybrid renewable and energy storage	917,022
Total New Resources	14,888,520

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022.
2. Generation from existing resources assumes normal hydro conditions and P50 wind and solar.

Electric Resource Need

Reliability is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity for resource adequacy (reliability)**: PSE must have the capability to meet customer's electricity needs during periods of peak demand;
2. **Hourly energy**: PSE must have enough energy available in every hour to meet customer's electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the requirements of the Clean Energy Transformation Act.

Meeting Peak Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of existing coal resources, PSE is forecast to begin to experience a peak capacity

shortfall starting in 2026. PSE uses a loss of load probability (LOLP) consistent with the Northwest Power and Conservation Council to determine the peak capacity need for its service territory. Using the LOLP methodology, before any new demand-side resources, it was determined that 907 MW of capacity would be needed by 2027 and 1,381 MW of capacity by 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis.

The resource adequacy analysis is complex and ensures the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro, wind and solar generation, equipment failure and plant forced outages, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Resource adequacy requires that the full range of potential demand conditions are met, even if the potential of experiencing those conditions is relatively low.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar) and energy limited resources (batteries, pumped hydro storage and demand response), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility because it depends upon interactions between the various resources that make up each utility's unique system and is dependent on load shapes and supply availability. As a result, it is hard to compare the ELCC of PSE's resources with those of other entities and even PSE's ELCC's will change over time as system conditions change. A full description of the peak capacity and ELCC values is in Chapter 7.

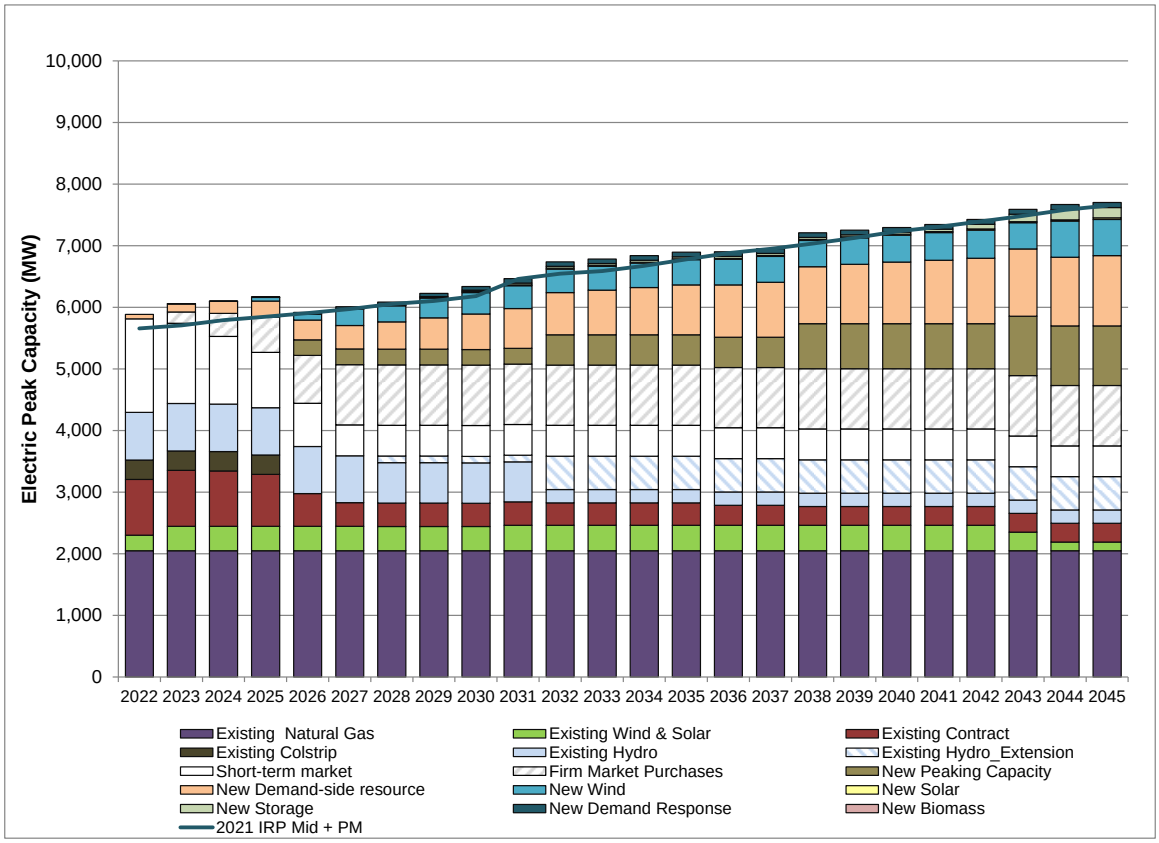
In addition to firm resources, PSE currently relies on market purchases from Mid-C to meet capacity needs. Evaluation of the existing wholesale electric market resulted in a recommendation that a portion of the available Mid-C transmission be used for firm resource adequacy (RA) qualifying capacity contracts or a reliable firm capacity resource in place of short-term energy purchases. Figure 3-5 shows, in annual increments, the conversion from short-term energy purchases to firm RA qualifying capacity purchases. As a result, in this IRP reliance on the availability of short-term market purchases at peak gradually declines over a 5-year period by 200 MW per year through the year 2027. The gray area shows PSE's total available transmission to the Mid-C market. After 2026, short-term market purchases stabilize at 500 MW and firm RA qualifying capacity purchases at 979 MW.

Figure 3-5: Short Term Market converted to Firm Resource Adequacy Qualifying Capacity Purchases

Year	Available Mid-C transmission	Short Term Market	Firm RA Qualifying Capacity Purchases
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

Figure 3-6 shows the preferred portfolio combination of new and existing resources required to meet the peak capacity need for the IRP mid demand forecast with an appropriate planning margin, and it reflects the peak capacity contribution of these resources. The graph also shows the market risk adjusted firm capacity (in the gray shaded bars) that will replace existing short-term Mid-Columbia energy contracts.

Figure 3-6: Preferred Portfolio Meeting Electric Peak Capacity and Reducing Market Risk



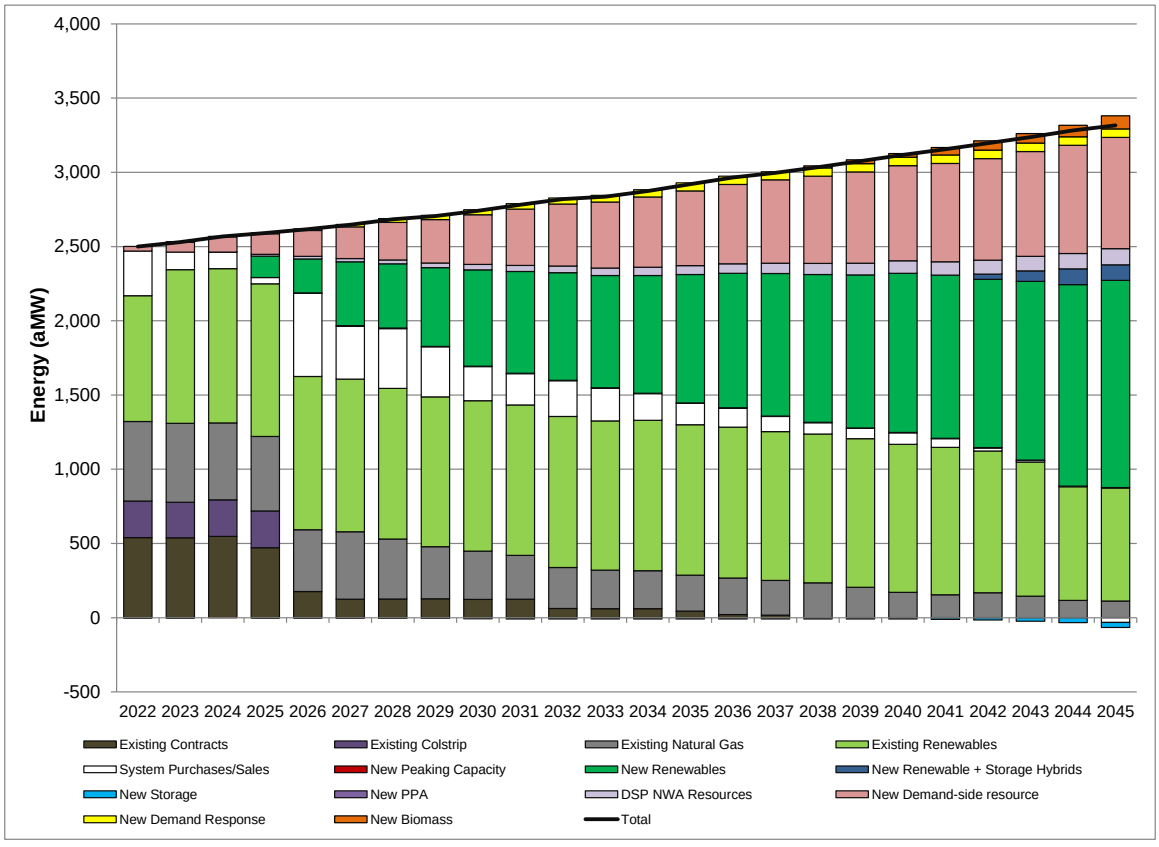
Renewable and distributed resources contribute to meeting peak capacity needs, however, peaking capacity is also needed to maintain reliability and meet required resource adequacy standards. The more than 750 MW of coal removed from PSE's portfolio by the end of 2025 is first replaced by demand-side resources, distributed energy resources and wind generation. Just 255 MW of new flexible, dispatchable capacity is added by 2026 to maintain reliability. The capacity need increases because an increase in balancing requirements is required to support the new intermittent renewable resources added to comply with CETA.

PSE evaluated early economic retirement of existing resources but that appears to increase cost. However, the economic dispatch of existing resources decreases significantly through the planning horizon as seen Figure 3-3 and is discussed further below.

Meeting Energy Need

Figure 3-7 shows the preferred portfolio combination of resources needed to meet the 2021 IRP mid demand forecast. Most of the energy need is met with renewable and distributed energy resources. The use of market purchases and sales declines over time. None of the energy requirements are satisfied with coal resources after 2025. The use of existing thermal resources significantly declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent for the highest dispatch units at the beginning of the planning horizon to 7 percent by the end. The pink bars represent demand-side resources, which significantly reduce total load. The black line on the chart is PSE's mid demand forecast and represents the demand at the generator, so it is grossed up for sales. This is different than the renewable need which is based on retail sales. Distributed energy storage resources are included in the portfolio but are barely visible in this chart because they are a net zero resource, meaning they do not produce any energy but rather store the energy produced by other generators. The storage resources appear as a negative value, below the line towards the end of the time horizon, and represent the energy stored.

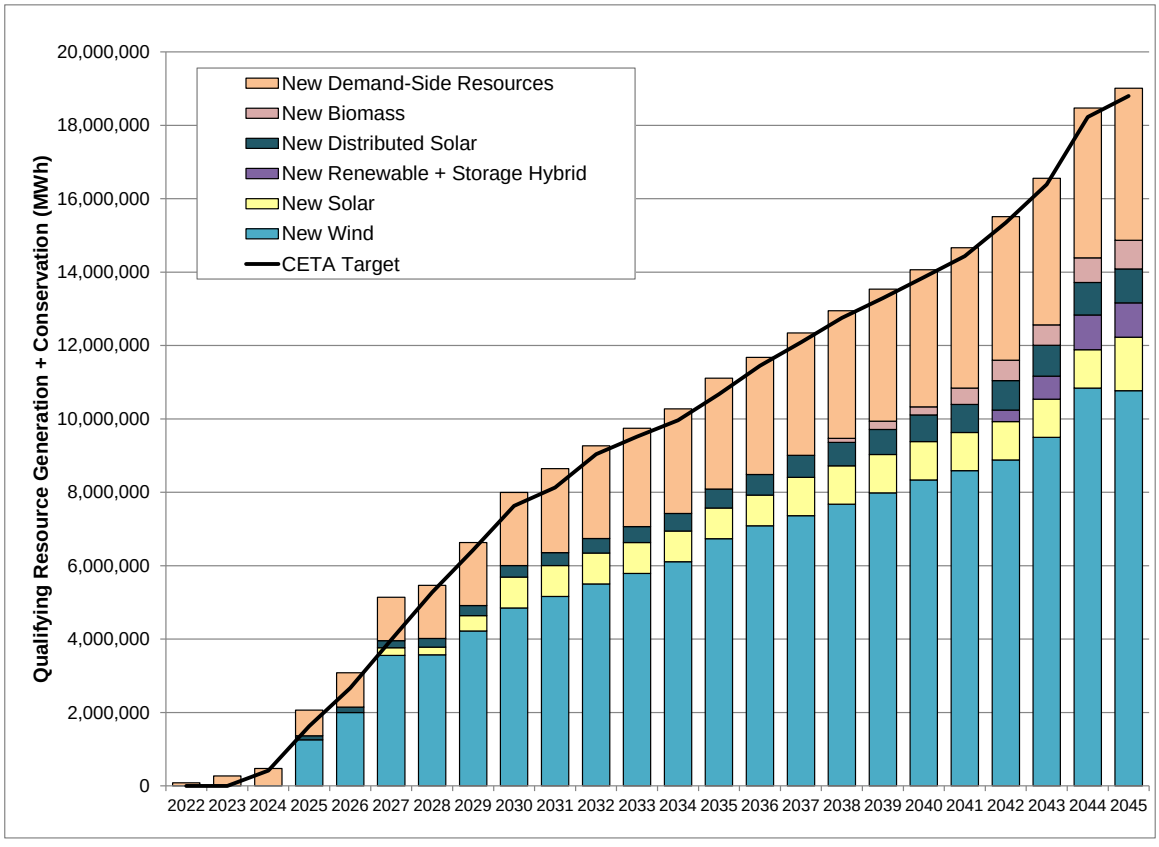
Figure 3-7: Preferred Portfolio Meeting Energy Requirements



Meeting Renewable Energy Need

The renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast, is described in Chapter 8. The preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-8 shows how the new renewable resources meet the 7.6 million MWh renewable requirement in 2030 and 17.1 million MWh renewable requirement in 2045. Demand-side resources (DSR) significantly reduce loads and lower the renewable need; these include cost-effective energy efficiency, codes and standards, distribution efficiency and customer solar PV. The majority of the remaining renewable resource need is met by new wind, and then solar. Wind additions include in Montana, Wyoming and eastern Washington wind. Solar additions include utility-scale solar in eastern Washington, and distributed energy solar resources include delivery system non-wire alternatives and ground-mounted and rooftop solar PV. The chart below shows the total annual energy (MWh) produced by these resources.

Figure 3-8: Preferred Portfolio Meeting Renewable Energy Requirements



Key Findings by Resource Type

Distributed Energy Resources

There is no single perfect answer or resource that will solve all of the peak, energy and renewable needs. That is why a balanced portfolio is important, one that includes a mix of utility-scale and distributed energy resources, and a mix of intermittent, energy-limited and firm capacity resources. All of these are important components when determining the portfolio mix. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. DERs make lower peak capacity contributions and have higher costs, but they play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits.

ENERGY EFFICIENCY. PSE has never limited the funding needed to meet energy savings targets and has consistently met and exceeded the energy savings targets called for in the Energy Independence Act (RCW 19.285). In each two-year program period from 2014 through 2019, PSE set electric savings targets that were 13 percent, 9 percent and 10 percent higher than required by the Energy Independence Act, and PSE's actual savings were 20 percent, 14 percent and 14 percent higher, respectively, than PSE's targets.

PSE encourages customers to bundle as many energy efficiency measures together as possible. This is true in both the business and residential efficiency programs. In fact, the residential program offers a bonus financial incentive for including multiple measures in a single application. PSE's program for commercial new construction and deep retrofits offers higher incentive rates for deeper reductions in energy use. The preferred portfolio includes 793 MW of the 840 MW estimated technical potential for energy efficiency found in the Conservation Potential Assessment.

Energy efficiency is just one of the demand-side resources analyzed in this IRP. All of the demand-side resources are described in Chapter 2 and Appendix D.

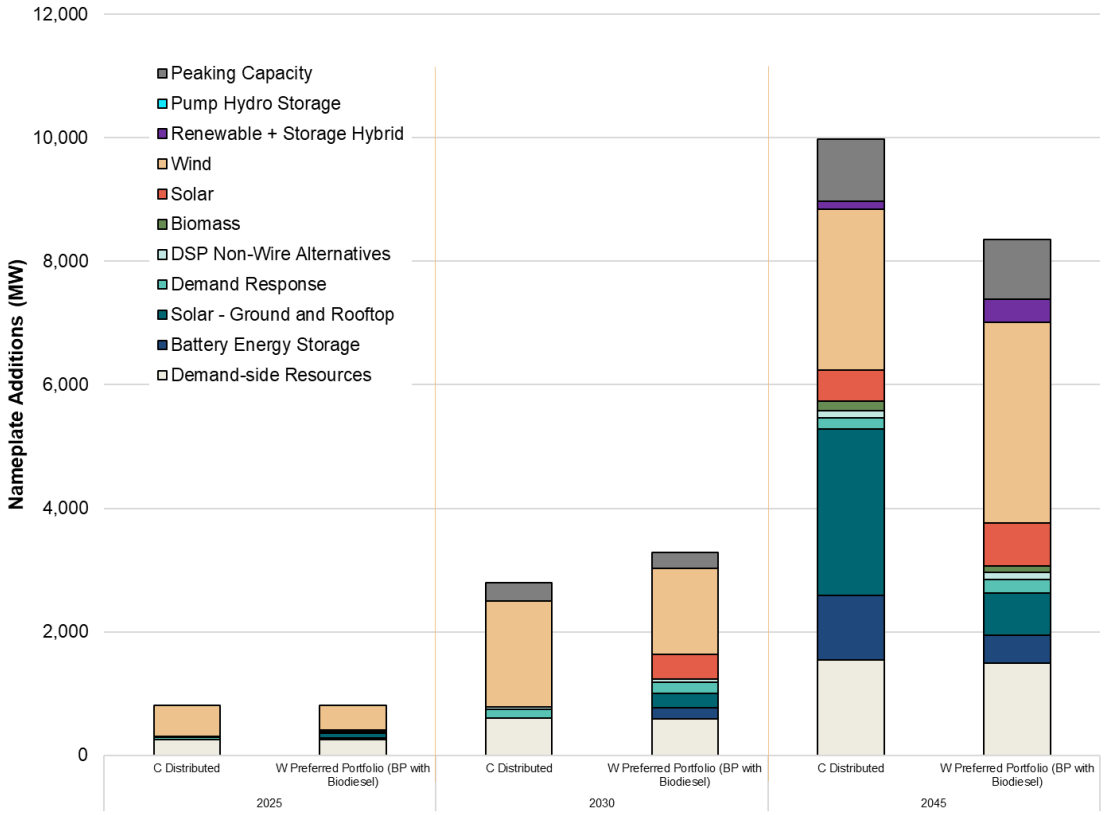
BATTERY ENERGY STORAGE. The preferred portfolio includes four battery energy storage systems that range in duration from 2 to 6 hours and pumped storage hydro with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with small needs of short duration. Batteries also work as a solution for local distribution upgrades and capacity needs. In the optimized portfolio results, additional energy storage was not part of the optimized portfolio solution until the last 5 to 10 years of the planning horizon when the renewable requirement increased to more than 90 percent of delivered load. However, taking into account risk of transmission and additional customer benefits, battery energy storage is accelerated in the preferred portfolio. The lower peak capacity credit of energy storage means significantly more

battery energy storage resources are needed to match the capacity provided by combustion turbines (the lowest cost resource). The preferred portfolio adds some distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031.

SOLAR – GROUND AND ROOFTOP. Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given the transmission constraints involved in bringing remote resources to PSE's service territory, distributed solar resources have become an important part of the solution. PSE modeled both ground-mount and rooftop solar as an option to both meet CETA renewable requirements and local distribution system needs. The distributed solar includes options for both customer-owned solar (net-metering) and PSE-owned solar resources.

In Sensitivity C, which restricts transmission availability compared to the Mid Scenario portfolio, PSE analyzed the risk of obtaining new transmission contracts to eastern Washington and the availability of re-using existing transmission contracts. Based on these restrictions, more renewable resources are needed in western Washington to meet CETA renewable requirements, and the portfolio model waited until the end of the planning period to add a significant amount of distributed resources. The preferred portfolio takes the same amount of distributed resources and ramps them in over time starting in 2025 for a total of 680 MW of distributed solar. This is in addition to the 622 MW of net-metered, customer-owned solar for a total of 1,302 MW of distributed solar by 2045. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting peak capacity need because it provides very little peak capacity value since PSE is a winter peaking utility. Figure 3-9 compares the preferred portfolio and Sensitivity C resource builds.

Figure 3-9: Resource Builds – 2021 IRP Preferred Portfolio and Sensitivity C (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



DEMAND RESPONSE. PSE modeled 16 demand response programs totaling 222 MW in nameplate capacity. Of those 16 programs, there are 4 different direct load control (DLC) hot water heater programs, along with critical peak pricing, DLC heating, EV charging, curtailment and critical peak pricing (CPP). The CPP programs are similar to a time-of-use (TOU) program.

To reflect the time needed to enroll customers in programs, five of the programs are ramped in starting in 2023, two programs are ramped in starting in 2025, and the remaining seven programs are ramped in starting in 2026. The five programs starting in 2023 were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers. The total demand response program grows to 195 MW nameplate capacity by 2031. By 2045, an additional 21 MW of demand response is cost effective for a total of 217 MW of the 222 MW technically available.

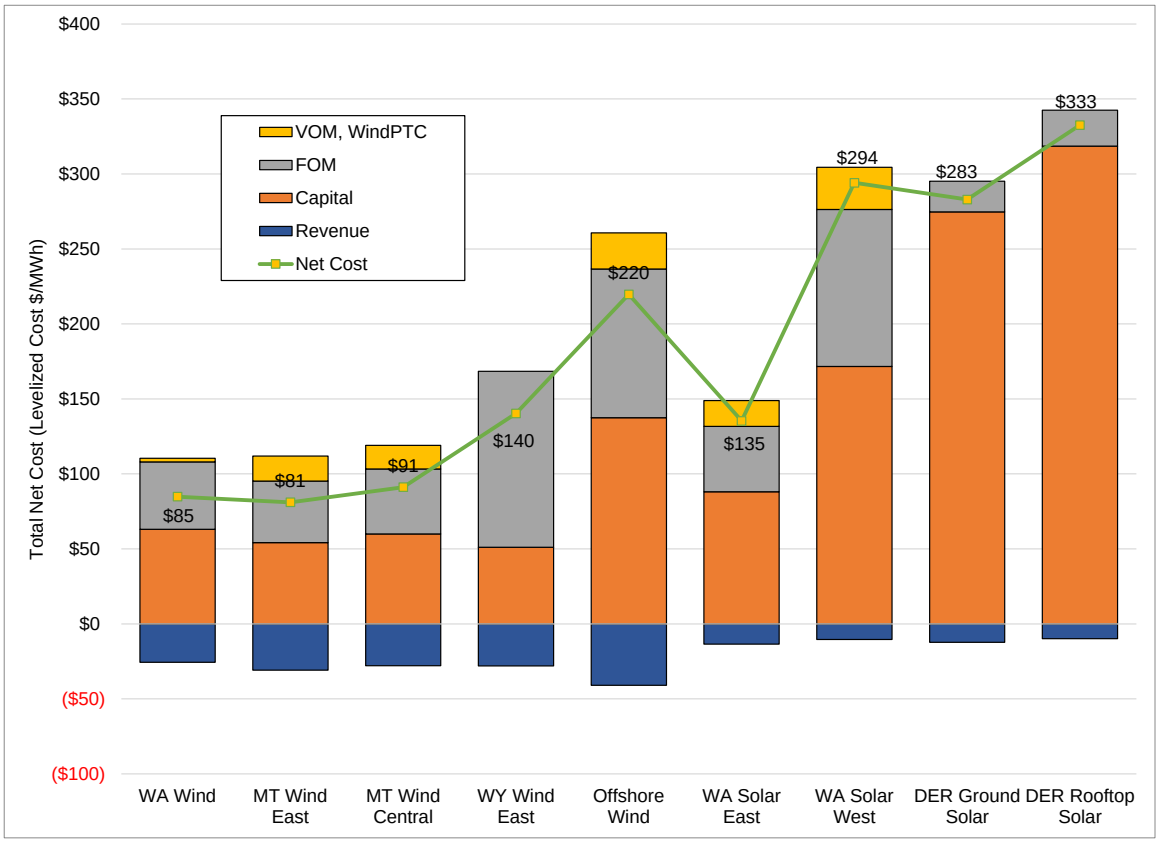
GRID MODERNIZATION. Proactive investments in grid modernization are critical to support the clean energy transition and maximize benefits. Investments in the delivery system are needed to deliver energy to PSE customers from the edge of PSE's territory and to support DERs within the delivery grid. Specific delivery system investments will become known when energy resources, whether centralized or distributed, begin to be sited through the established interconnection processes. The 10-year delivery infrastructure plans are described in Appendix M.

Utility-scale Renewable Resources

Significant investment in utility-scale renewable resources, in addition to DERs, will be needed to ensure that 100 percent of all retail electricity sales is served with renewable resources.

WIND AND SOLAR RESOURCES. The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources also contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio that relies on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the portfolio cost. Increased renewable diversity can improve contribution to capacity needs, however resources outside of the Pacific Northwest region are limited given transmission constraints. After Montana and Wyoming wind, the costs of eastern Washington wind and solar are very close. Figure 3-10 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resources to meet CETA renewable requirements, followed by eastern Washington wind and solar. The levelized costs are calculated based on total resource costs; these include capital costs, variable operations and maintenance, and fixed operations and maintenance. Some resources include benefits from the production tax credit (PTC), and the investment tax credit (ITC). A full description of the ranges for the PTC and ITC is included in Appendix G. All resources include a benefit called revenue. This is the value of the resource in the market and is calculated as generation times the electric power price for every hour. The revenue and costs of the resources are calculated for every hour and then aggregated up to annual costs and benefit. These costs are then levelized by using net present value in 2022 dollars. Actual resource costs obtained through an RFP process could yield a different conclusion.

Figure 3-10: Levelized Cost of Wind and Solar Resources



TRANSMISSION CONSTRAINTS. Transmission capacity constraints have become an important consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the clean energy transformation targets. Thermal resources can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand. In contrast, renewable resources are site-specific and have variable generation patterns that depend on local wind or solar conditions, therefore they cannot always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will also be needed, but was assumed to be unconstrained due to delivery system planning processes and the specific projects identified in Appendix M.

The available transmission to eastern Washington can range from 700 MW to over 3,200 MW depending on the availability of new transmission contracts, upgrades on the system and the repurposing of existing contracts. PSE modeled a potentially available 750 MW of transmission from Montana and 400 MW of transmission from Wyoming. The full 750 MW of Montana wind and 400 MW of Wyoming wind appear to be cost-effective in this portfolio. There is significant risk with Wyoming wind because new transmission will need to be constructed to Wyoming, and PSE will also need to acquire new firm transmission contracts. After Montana and Wyoming wind are added to the portfolio, there is still an additional 600 MW of eastern Washington wind and 400 MW of eastern Washington solar needed by 2030. Given the risk in available transmission, over 200 MW of distributed solar is added to the portfolio to meet the 80 percent CETA renewable target in 2030. The actual location and type of renewable resources will depend on available transmission.

BIOMASS. Between 2035 and 2045, over 100 MW of biomass is added to the preferred portfolio. Although biomass has a higher capital cost than wind and solar, it is a baseload resource with an 85 percent capacity factor, which means that fewer biomass resources are needed to produce the same amount of energy that a resource such as solar can produce. PSE modeled wood waste biomass connected to lumber mills. Given the total number of mills located in western Washington, PSE estimates that around 150 MW of biomass may be feasible.

HYBRID RESOURCES. After 2040, 375 MW of hybrid wind and battery resources are added to the portfolio. Connecting a battery to an intermittent renewable resource helps to firm the capacity of the renewable resource so that it is more reliable during peak events and has a higher peak capacity contribution. However, with the battery being used to firm up the capacity of the wind resource, it is not available to meet flexibility needs, and it does not provide benefits to the transmission and distribution system. As a result, using the battery as an independent, distributed resource has more benefits to PSE than connecting it directly to a renewable resource. Hybrid resources are not cost competitive until the end of the time horizon.

Peaking Capacity with Biodiesel

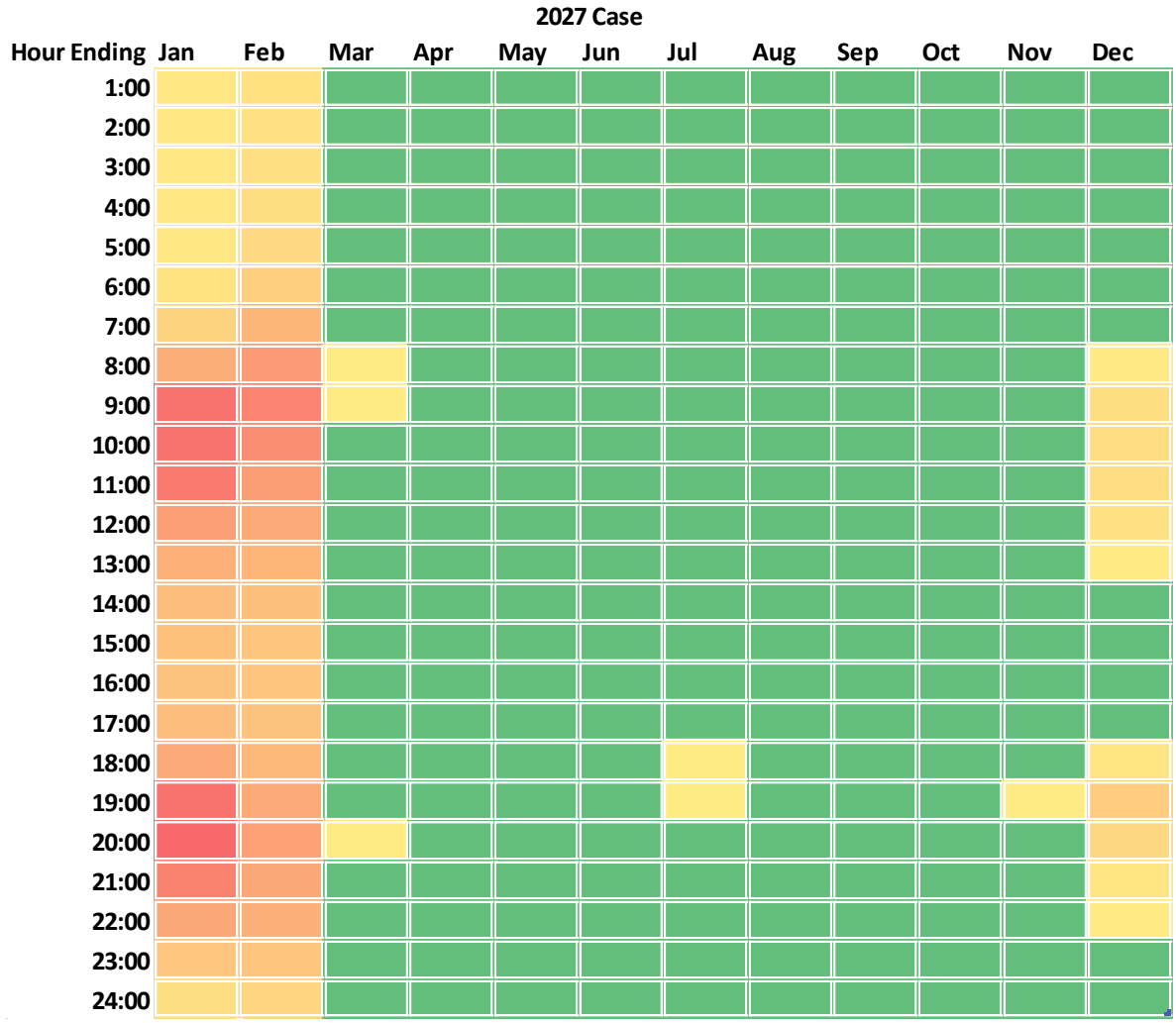
Beyond 2025, all sensitivities show a need for flexible, peaking capacity when 750 MW of coal generation is removed from PSE's portfolio in 2026. PSE is committed to pursuing all clean capacity resources first. The current modeling results show alternative fuel enabled combustion turbines as the most cost-effective resource to meet the capacity resource needs that cannot be otherwise met by demand-side resources and distributed and renewable resources. The model selected dispatchable combustion turbines as the least cost resource in particular to meet peak reliability needs, especially during periods of high load due to extremely cold weather conditions when renewable generation may be limited.

FUEL SUPPLY. In the resource adequacy analysis, PSE evaluated the biodiesel fuel supply needed for the peakers to maintain reliability. In 95 percent of simulations, the peakers are needed to run for 10,000 MWh or less to maintain resource adequacy, which is around 15 hours of run time annually. The maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[2] on biofuel production, the total annual production of biodiesel in Washington state is 114 million gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel, or about 0.7 percent of Washington State's 2020 annual production.

PEAK CAPACITY. The 12x24 table in Figure 3-11 shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number of hours of lost load summed by month and hour of day. The majority of the lost load hours occur in the winter months. In this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events by adding new resources. Current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability. The portfolio model needs to meet the loss of load events with resources that can be dispatched for 24 hours or more. Further discussion of the resource adequacy analysis can be found in Chapter 7.

2 / https://www.eia.gov/biofuels/biodiesel/production/

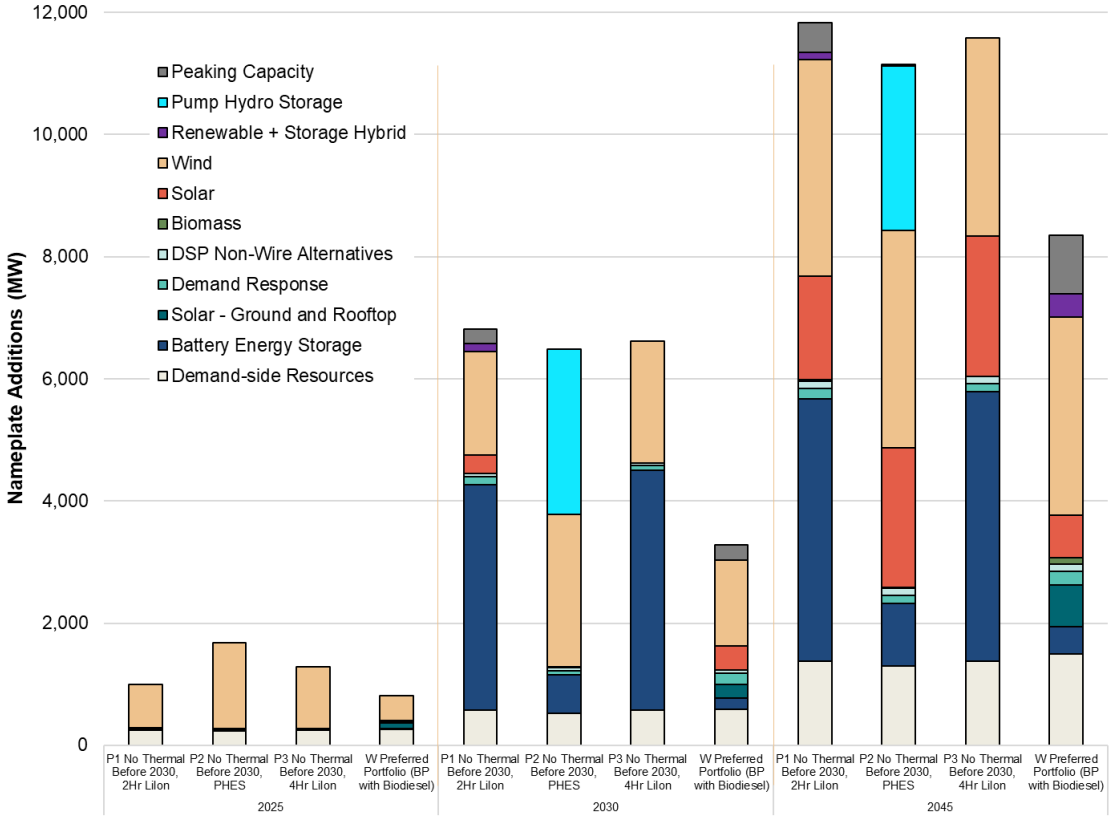
Figure 3-11: Loss of Load Hours for 2027



PSE's winter peak has notably different characteristics than a summer peak in other parts of the Western Interconnect. Summer peaking events occur in the late afternoon/evening when the day is the hottest and only last a few hours in the evening. Energy storage is a good solution for summer peaking events. In contrast, winter events can last several days at a time and temperatures can drop low during the night and stay low throughout the day. Since energy storage is a short duration resource that has a low peak capacity credit, it is not a good fit for winter peaks. With lower peak capacity credit, more energy storage resources are needed to replace the new peaking capacity added in the portfolio.

To better understand how energy storage can meet PSE's peak needs, PSE evaluated several portfolios in Sensitivity P. Sensitivity P removed new peakers as an option and forced the model to find alternative solutions. In the P1 portfolio, the first resource selected to fill peak need was 2-hour lithium-ion batteries. In the P2 portfolio, 2-hour lithium-ion and flow batteries were removed as an option and the model optimized to a solution involving a combination of pumped hydro storage and 4-hour lithium-ion batteries. The P3 portfolio removed the pumped hydro storage option and just added 4-hour lithium-ion batteries to meet peak needs. Figure 3-12 shows the total builds for the preferred portfolio and portfolios P1, P2 and P3. It takes a significant amount of energy storage and associated cost to replace the biodiesel peaker.

Figure 3-12: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity P, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Without access to the biodiesel peaker, Sensitivity P produced much higher portfolio costs. Figure 3-13 compares the total portfolio costs for 2045 for the preferred portfolio and portfolios P1, P2 and P3. The lowest cost portfolio is portfolio P2 at $22.85 billion, $6.7 billion more than the preferred portfolio.

Figure 3-13: Portfolio Cost for the Preferred Portfolio and P1, P2 and P3 Portfolios

Portfolio	Portfolio Cost (Billion $, 24-year levelized)
Preferred Portfolio	$16.11
P1: 2-hr Li-Ion	$30.84
P2: Pumped storage hydro	$22.85
P3: 4-hr Li-Ion	$39.01

While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional peaking capacity plants of any kind in the future, alternative fuel peakers appear to be the least cost resource for meeting peak reliability needs at the time of this analysis. In all sensitivities that allowed the addition of new combustion turbines, at least one combustion turbine is added by 2026 and a second combustion turbine is added by 2030. Combustion turbines have the highest peak capacity value because of their ability to dispatch as needed with no duration limits. PSE is further exploring renewable and alternative fuel supply availability and technology.

Preferred Portfolio Decisions

A full discussion of all portfolios modeled in the 2021 IRP can be found in Chapter 8. This section focuses on the preferred portfolio and captures the decisions that informed the 10-year clean energy action plan and the 24-year resource plan.

Customer Benefits Analysis and Costs

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. As a result, the analysis of the equitable distribution of burdens and benefits is new to the resource planning process in the 2021 IRP. PSE is excited to incorporate these new ideas into the process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. A full discussion of how the customer benefit indicators were established is included in Chapter 8. Figure 3-14 shows the results of the

Customer Benefits Analysis and the overall portfolio rankings at the 24-year time horizon. These outputs have been color coded from red (least benefit) to green (most benefit). The Mid portfolio is the lowest cost portfolio that meets CETA requirements at $15.53 billion, but in terms of customer benefit indicators, it ranks at number 14 out of 22. To be included in the Customer Benefit Analysis portfolios must maintain consistency across demand and electric price forecasts, meet CETA requirements and represent current carbon regulation; therefore, not all portfolios were included.

Figure 3-14: Customer Benefits Analysis –Overall Portfolio Rank and Costs for 2045

Portfolio Sensitivity	Overall Rank	24-year Levelized Portfolio Cost (Billion $)
1 Mid	14	$15.53
A Renewable Overgeneration	13	$17.11
C Distributed Transmission	20	$16.35
D Transmission/build constraints - time delayed (option 2)	11	$15.54
F 6-Yr DSR Ramp	17	$15.54
G NEI DSR	10	$15.24
H Social Discount DSR	8	$15.77
I SCGHG Dispatch Cost - LTCE Model	3	$15.41
K AR5 Upstream Emissions	12	$15.56
M Alternative Fuel for Peakers – Biodiesel	1	$15.44
N1 100% Renewable by 2030 Batteries	6	$32.03
N2 100% Renewable by 2030 PSH	15	$66.64
O1 100% Renewable by 2045 Batteries	9	$23.35
O2 100% Renewable by 2045 PSH	5	$46.95
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$30.84
P2 No Thermal Before 2030, PHES	18	$22.85
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$39.01
V1 Balanced portfolio	4	$16.06
V2 Balanced portfolio + MT Wind and PSH	16	$16.61
V3 Balanced portfolio + 6 Year DSR	7	$16.26
W Preferred Portfolio (BP with Biodiesel)	2	$16.11
AA MT Wind + PHSE	19	$15.84

As shown in Figure 3-14, the Customer Benefit Analysis suggests Sensitivity M is the portfolio that provides the greatest benefit to PSE customers. PSE recognizes that this portfolio has many desirable attributes, including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which reduce transmission risk and may provide benefits on the distribution system.

Comparing the costs of Sensitivity M with Sensitivity W yields only a relatively small increase in costs and provides a greater investment in distributed energy resources, thus balancing transmission risks. Therefore, PSE has selected Sensitivity W, the Balanced Portfolio with biodiesel fuel, as the preferred portfolio.

Figure 3-15 compares the portfolio M and W builds by 2030. Portfolio W is a balanced portfolio that takes earlier action on DERs and includes more distributed solar and battery energy storage in the first 10 years of the plan than portfolio M.

Figure 3-15: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity M, Transmission Build Constraint Cumulative Additions by Nameplate (MW)

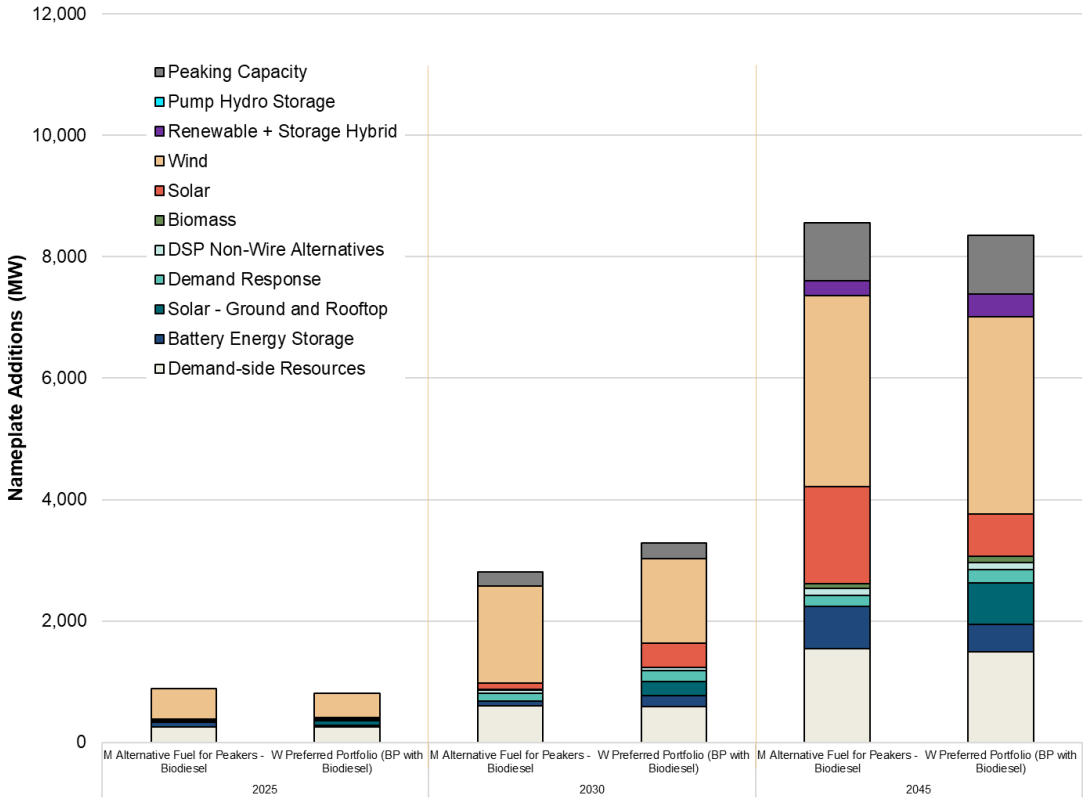


Figure 3-16 shows the results of the Customer Benefits Analysis for the 10-year time horizon. With the addition of the distributed energy resources in the early part of the planning horizon, Sensitivity W ranked number 1 in the 10-year rankings.

Figure 3-16: Customer Benefits Analysis –Overall Portfolio Rank for 2031

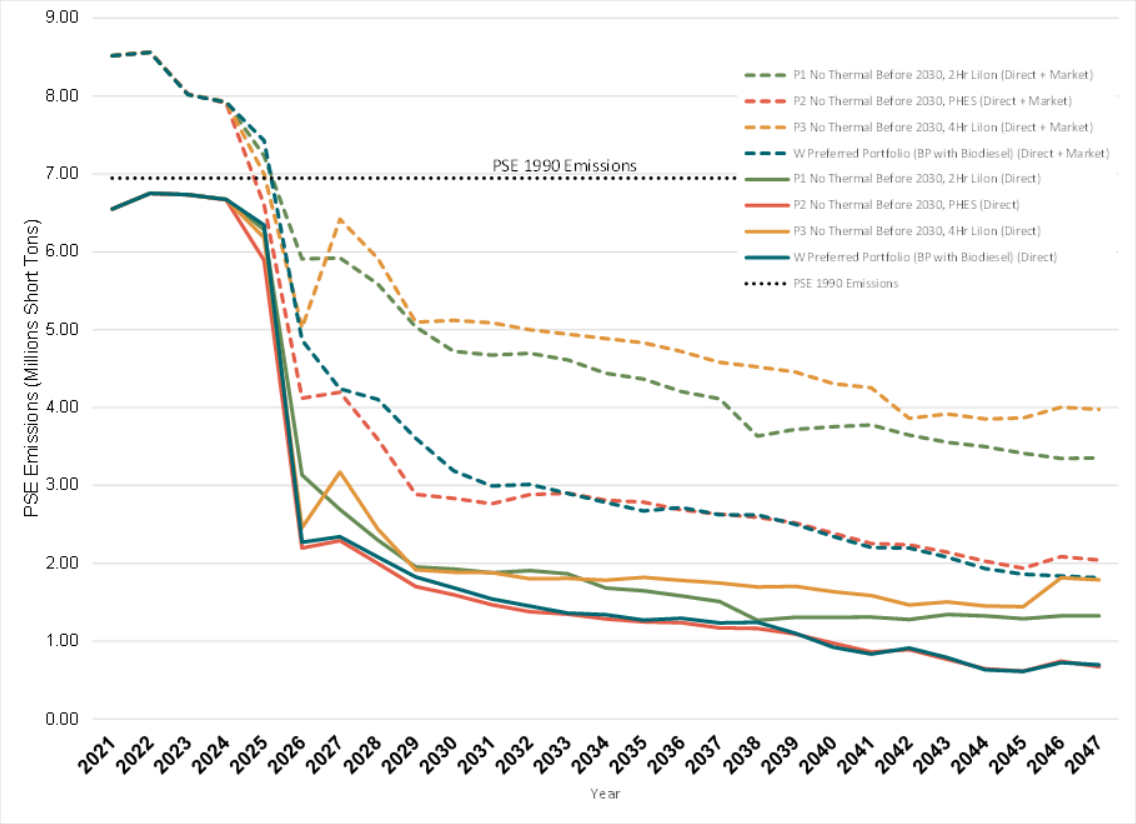
Portfolio Sensitivity	Overall Rank	10-year Levelized Portfolio Cost (Billion $)
1 Mid	12	$6.65
A Renewable Overgeneration	9	$7.09
C Distributed Transmission	20	$6.65
D Transmission/build constraints - time delayed (option 2)	15	$6.68
F 6-Yr DSR Ramp	11	$6.50
G NEI DSR	16	$6.37
H Social Discount DSR	18	$6.47
I SCGHG Dispatch Cost - LTCE Model	17	$6.61
K AR5 Upstream Emissions	19	$6.71
M Alternative Fuel for Peakers – Biodiesel	8	$6.67
N1 100% Renewable by 2030 Batteries	5	$10.86
N2 100% Renewable by 2030 PSH	14	$19.92
O1 100% Renewable by 2045 Batteries	13	$7.51
O2 100% Renewable by 2045 PSH	4	$11.77
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$13.36
P2 No Thermal Before 2030, PHES	7	$9.94
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$15.38
V1 Balanced portfolio	2	$6.90
V2 Balanced portfolio + MT Wind and PSH	6	$7.13
V3 Balanced portfolio + 6 Year DSR	3	$6.84
W Preferred Portfolio (BP with Biodiesel)	1	$6.91
AA MT Wind + PHSE	10	$6.78

Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-17 compares CO_2 emissions for Sensitivity W, preferred portfolio with Sensitivity P portfolios, where the peaking capacity is replaced with different combination of renewable or non-emitting resources. The chart shows direct emissions from the generating resources plus upstream emissions in the solid lines, and direct emissions plus upstream emissions plus market purchases in the dashed lines. The graph does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to

2045. Rather direct emissions are shown for analysis. Direct emissions decrease over time as thermal resources are replaced with renewable generation. In Sensitivity P, more energy storage resources are added to the portfolio and market purchases are used to charge the storage resources since there is not enough surplus energy in PSE's portfolio. The market purchases cause a large increase in emissions; as can be seen by the difference between the solid and dashed lines for the Sensitivity P portfolios. Also, comparing the solid lines for Sensitivity W, preferred portfolio, and Sensitivity P shows that the direct emissions from PSE's resources are lower in Sensitivity W, preferred portfolio. This is because the heat rate of the new peaking resource, run on biodiesel fuel, is more efficient than the older thermal generators in PSE's fleet, the new peaking resource has lower emissions. When new energy storage resources are added in Sensitivity P portfolios, the increased generation from the existing fleet increases direct emissions.

Figure 3-17: CO_2 Emissions – Preferred Portfolio and Sensitivity P
(Solid lines show direct emissions plus upstream emissions, dotted lines show direct emissions plus upstream emissions plus market purchases. Does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



COST OF CARBON REDUCTIONS. To calculate the cost of reducing carbon emissions, PSE divided the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

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

Figure 3-18 compares the results of this calculation for the preferred portfolio, Sensitivity N (100 percent renewable resources by 2030), Sensitivity O (where all thermal resources are retired by 2045), and Sensitivity P (new peaking capacity is replaced with alternative resources). The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The preferred portfolio is very efficient at reducing portfolio emissions because it uses new peaking capacity fueled with biodiesel to meet peak capacity needs.

Figure 3-18: Cost of Emissions Reductions Compared – Mid Scenario, Preferred Portfolio and Sensitivities N, O and P

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / Billion $)
1 Mid Scenario Portfolio	53.87	$15.53	-
Preferred Portfolio	52.77	$16.10	0.52
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
O1 100% Thermal resources retired by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Thermal resources retired by 2045 – PHES	43.54	$46.95	3.04
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions

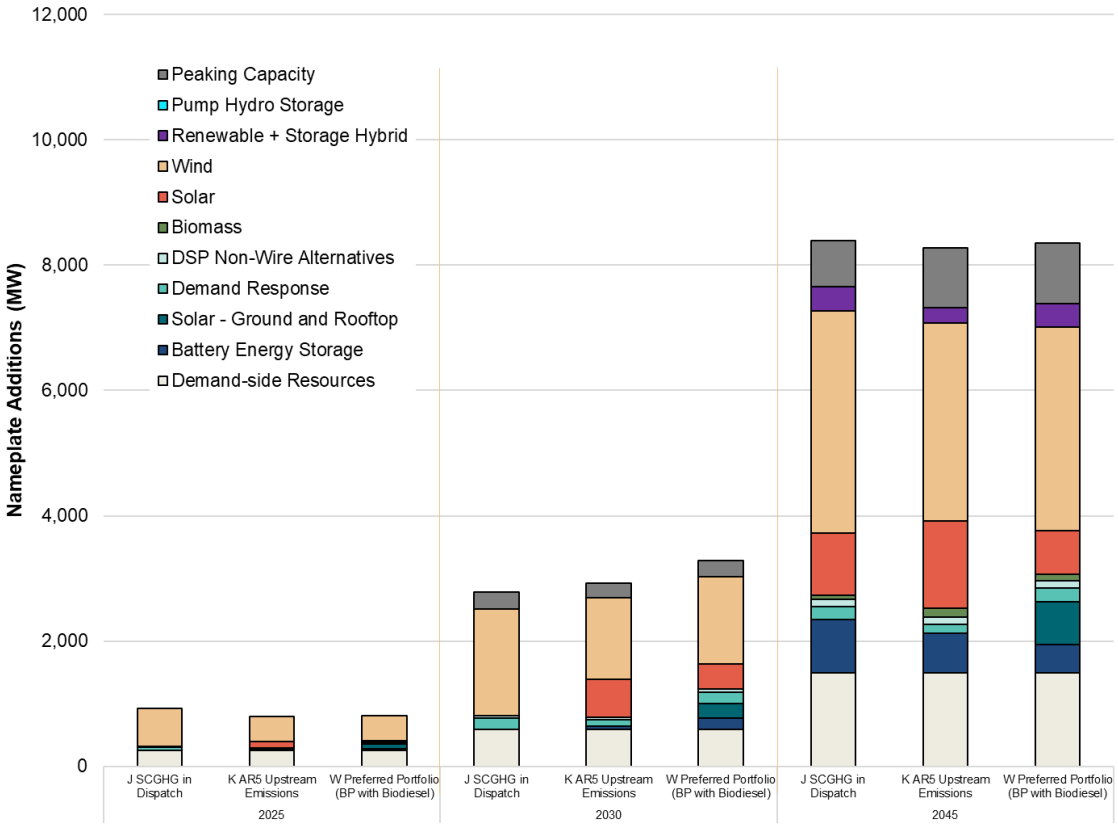
Social Cost of Greenhouse Gases (SCGHG)

CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resource options. As a result, PSE has modeled SCGHG as an adder in the portfolio model. The SCGHG is described in more detail in Chapter 5.

In response to stakeholder requests, PSE modeled different SCGHG approaches. Utilizing different SCGHG modeling approaches does not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements. Renewable resource requirements to comply with CETA are the key constraint that drives portfolio resource additions and costs. The different SCGHG modeling approaches are described in detail in Chapter 8.

In response to stakeholder requests, PSE also modeled an alternate upstream emission content. PSE applied upstream emission rate consistent with Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) in all portfolio modeling, and then evaluated a sensitivity using upstream emissions consistent with IPCC's Fifth Assessment Report (AR5). While AR5 increased upstream emissions for natural gas, it did not change resource builds or retirements compared to AR4. Figure 3-19 is a comparison of builds for the different modeling methodologies.

Figure 3-19: Resource Build for 2021 IRP Preferred Portfolio and Sensitivities J and K (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



Temperature Variations and Fuel Conversion Impacts

PSE evaluated temperature variations that increased the summer loss of load events. This temperature sensitivity is one model of possible weather changes and provides a preliminary view of a possible impact of warming temperatures as a result of climate change. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made to inform the preferred portfolio. Details are provided in Chapter 7 for the resource adequacy analysis, and portfolio results are presented in Chapter 8.

PSE will continue to model weather trends under different scenarios to better understand how summer extreme events can affect resource adequacy, but also to ensure that PSE continues to plan for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past three years, three separate regional events outside of PSE's control have occurred, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipates future changes to the resource adequacy analysis will include both winter and summer resource adequacy analyses, and PSE will also work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

In the 2021 Washington State legislative session, some proposals have been introduced that propose to convert from natural gas to electricity for power supply. This would significantly increase electric loads and associated peak loads. Since this would convert natural gas heating to electric heating, the majority of the increased loads would happen in the winter. PSE ran a sensitivity in this IRP to examine large-scale conversion of natural gas heating to hybrid electric heat pumps. This sensitivity increased electric loads by over 35 percent by 2045 and winter peak loads by over 17 percent by 2045. Natural gas sales decreased by 74 percent by 2045. This sensitivity assumed conversion to hybrid air-source heat pumps with natural gas backup that switch from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. More details on the Gas to Electric sensitivity results are presented in Chapters 8 and 9.

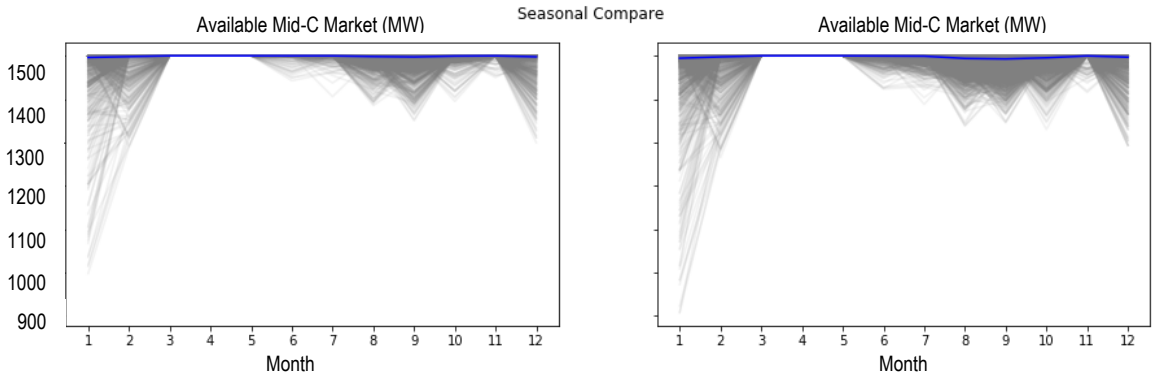
For future IRP work, PSE will look at integrating several of these scenarios to include temperature variations, gas-to-electric conversion and increased electric vehicle loads. Separately, each of these factors can change PSE's load shapes in different ways, but it is important to plan for how combined changes may affect PSE's load shapes.

Firm Resource Adequacy Qualifying Capacity Contracts

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model.

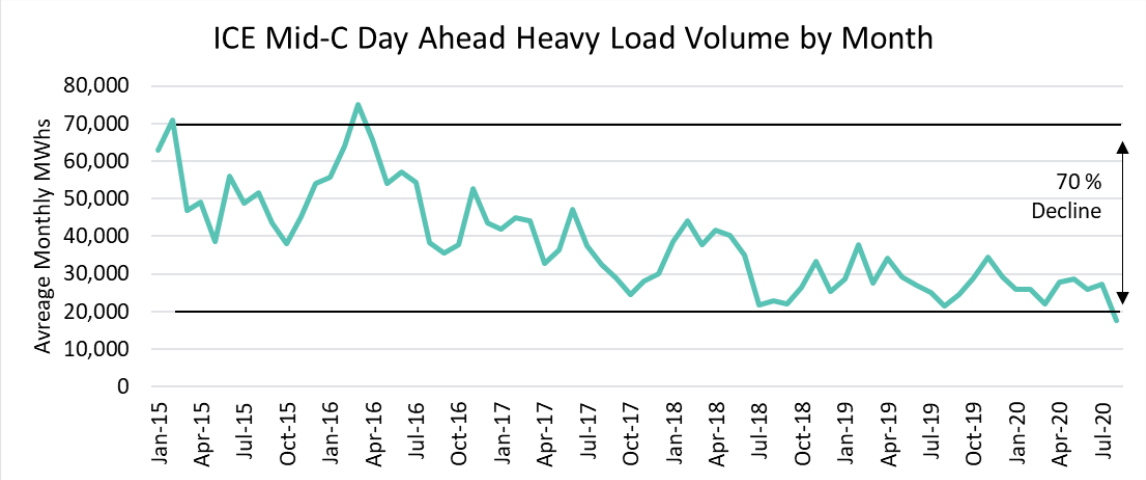
Figure 3-20 shows the results of the resource adequacy modeling. Over the last few years, several studies from regional organizations show that the Pacific Northwest may experience a capacity shortfall in the near term. PSE's resource adequacy model takes curtailment events from the Northwest Power and Conservation Council's resource adequacy model and allocates a portion of the curtailments to PSE's portfolio. The chart illustrates the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 3-20: Reduction to Available Mid-C Market



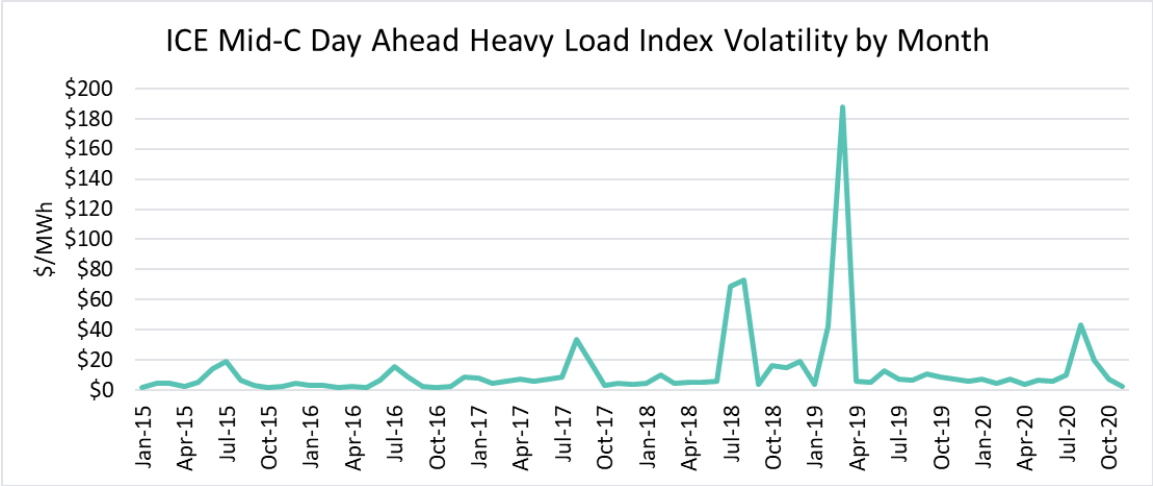
In the market risk assessment, PSE took this assessment further and analyzed the availability of the market during more recent events. Reductions in traded volume in the day-ahead market indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available for market participants to trade. This also is suggestive of more energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 3-21 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 3-21: Mid-C Day-ahead Heavy Load Volume Timeline



The market risk analysis also shows that price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip; in March 2019, when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020, during a west-wide heat event. The volatility of day-ahead heavy load prices is shown in Figure 3-22.

Figure 3-22: Volatility of Heavy Load Mid-C Day-ahead Prices



Coinciding with the retirement of legacy baseload capacity and the decline of market availability, several regional investor-owned utilities (IOUs) have reduced their assumptions of available market purchases in their IRPs. Compared with other IOUs in the region, PSE's market purchases are much higher than other IOUs, putting PSE at risk if short-term market purchases are not available.

Taking into account the results from the resource adequacy analysis, the downward trend in trading volumes over the last five years and the low availability of market during regional events, PSE proposes to reduce its reliance on short-term market purchases to 500 MW by 2027 and convert a portion of its 1,500 MW of Mid-C transmission to firm resource adequacy qualifying capacity contracts instead of relying on the short-term market. This means that the firm transmission is still available and will be evaluated during the RFP process for the lowest reasonable cost way to firm up the resources behind the transmission.

Reducing market purchases to 500 MW increases the peak capacity deficit in 2027 from 906 MW to 1,853 MW. In Sensitivity WX, PSE evaluated a portfolio in which available transmission to Mid-C was reduced and replaced with new peakers to address the capacity deficit. The result was a portfolio that added approximately 1,000 MW of peaking resources. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict. PSE's transmission can be used to procure new firm contracts or resources that can be delivered to Mid-C market hub and then used to deliver energy to PSE. The total cost of the preferred portfolio already includes estimates of the wholesale market price for the firm contracts proposed, but does not include any capacity premium that may be added. It

is this premium that is difficult to predict, and PSE will learn more about those costs and what is available in the next RFP.

The regional resource adequacy program is currently under development and will impact PSE's capacity need should PSE decide to participate. Sufficient program design details are not yet available to evaluate the program's impact on PSE's resource adequacy analysis, however, we know that the program will define the types of contracts that will qualify to meet resource adequacy. PSE will be able to assess program impacts in time for the IRP update in two years.

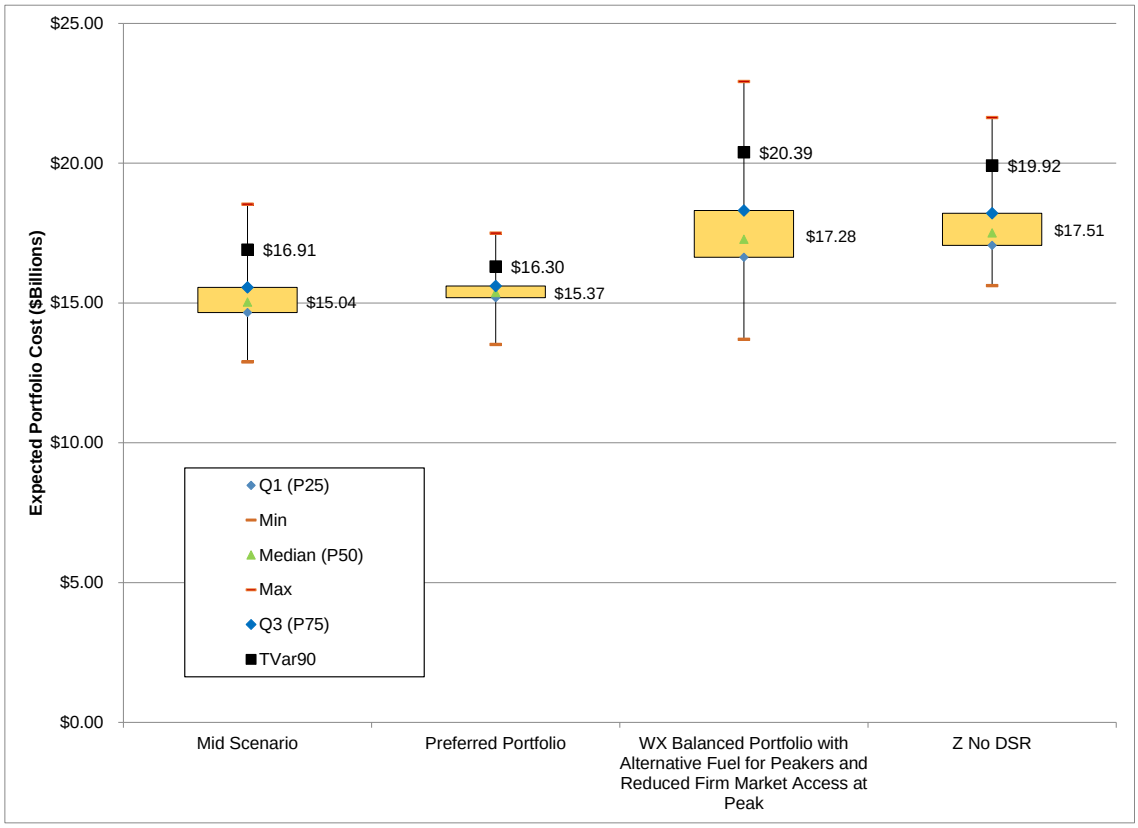
Summary of Portfolio Risk

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. For this purpose, PSE takes the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, natural gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

PSE's approach to the electric stochastic analysis hold portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information. Nevertheless, the result of the risk simulation provide an indication of portfolio costs risk range under varying input assumptions. In Figure 3-23, the expected portfolio costs for each portfolio are being compared across four portfolios; Mid, Preferred Portfolio, Sensitivity WX (Balanced portfolio with Market reduction), and Sensitivity Z (No DSR). The left axis represents the costs and the right axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio and is a measure of the center of the date. The interquartile range box represents the middle 50% of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

3 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Figure 3-23: Range of Portfolio Costs across 310 Simulations



The interquartile range for the Preferred Portfolio with Biodiesel is comparatively narrow and has the lowest TailVar90 at $16.3 billion dollars suggesting that the overall expected portfolio costs is the least variable compared to the other portfolios. The smaller range on the preferred portfolio indicates that this portfolio has the lowest volatility and the lowest risk than the other portfolios tested. Including conservation in the portfolio reduces both costs and risks, as can be seen in the comparison of costs and ranges with Sensitivity Z, No DSR. Sensitivity WX replaces the 1,000 MW of short-term market with frame peakers. In this portfolio, the costs are higher because of the cost of new resources, which is why the median cost is higher than the preferred portfolio. This portfolio also has a large range in costs, indicating higher volatility and risk. The conclusion of this simulation is that replacing the short-term market with natural gas plants does not reduce risk, it is simply exchanging market price risk for natural gas fuel risks. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The additions to the natural gas sales portfolio are summarized in Figure 3-24, followed by a discussion of the reasoning that led to the plan. Peak use during the winter heating seasons must be met in the natural gas analysis. PSE's winter heating season is from November to February; as a result, the years shown here reference the natural gas year, so 2025/26 means the natural gas year from November 2025 through October 2026.

Figure 3-24: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

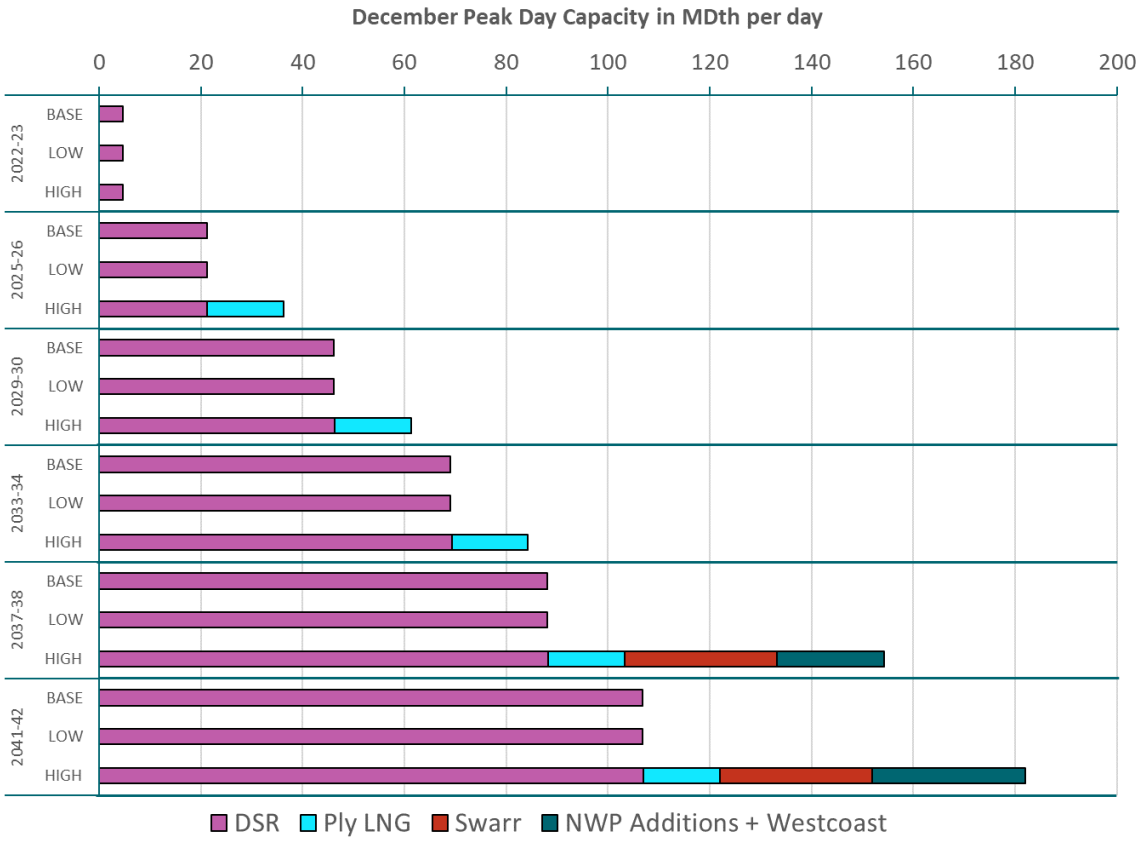
	2025/26	2030/31	2041/42
Conservation	21	53	107

The natural gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. In the draft 2021 IRP, conservation was the most cost effective resource, and it alone was enough to meet the need over the entire study period.

Natural Gas Sales Results across Scenarios

As with the electric analysis, the natural gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Three scenarios were tested in the 2021 IRP: Mid, Low and High. Figure 3-25 illustrates the lowest reasonable cost portfolio of resources across these three potential future conditions.

Figure 3-25: Natural Gas Sales Portfolios by Scenario (MDth/day)

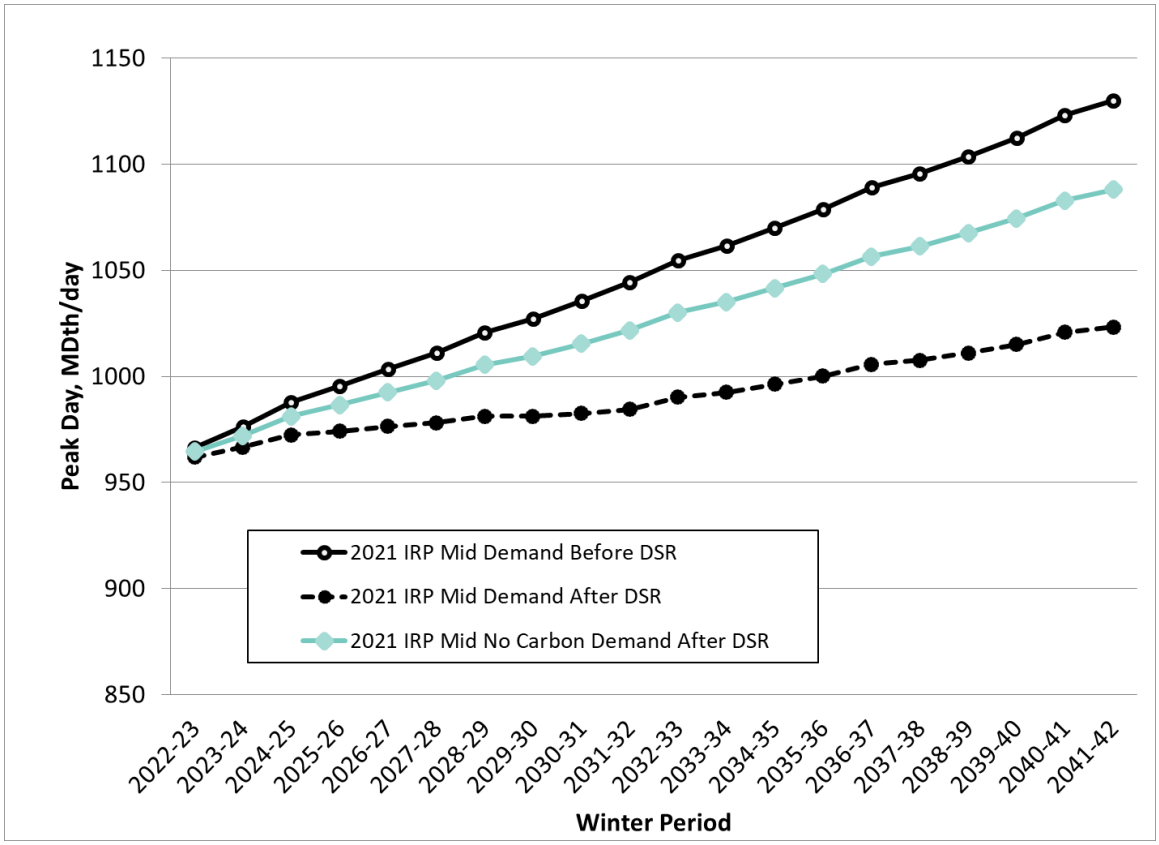


Key Findings by Resource Type

Demand-side Resources

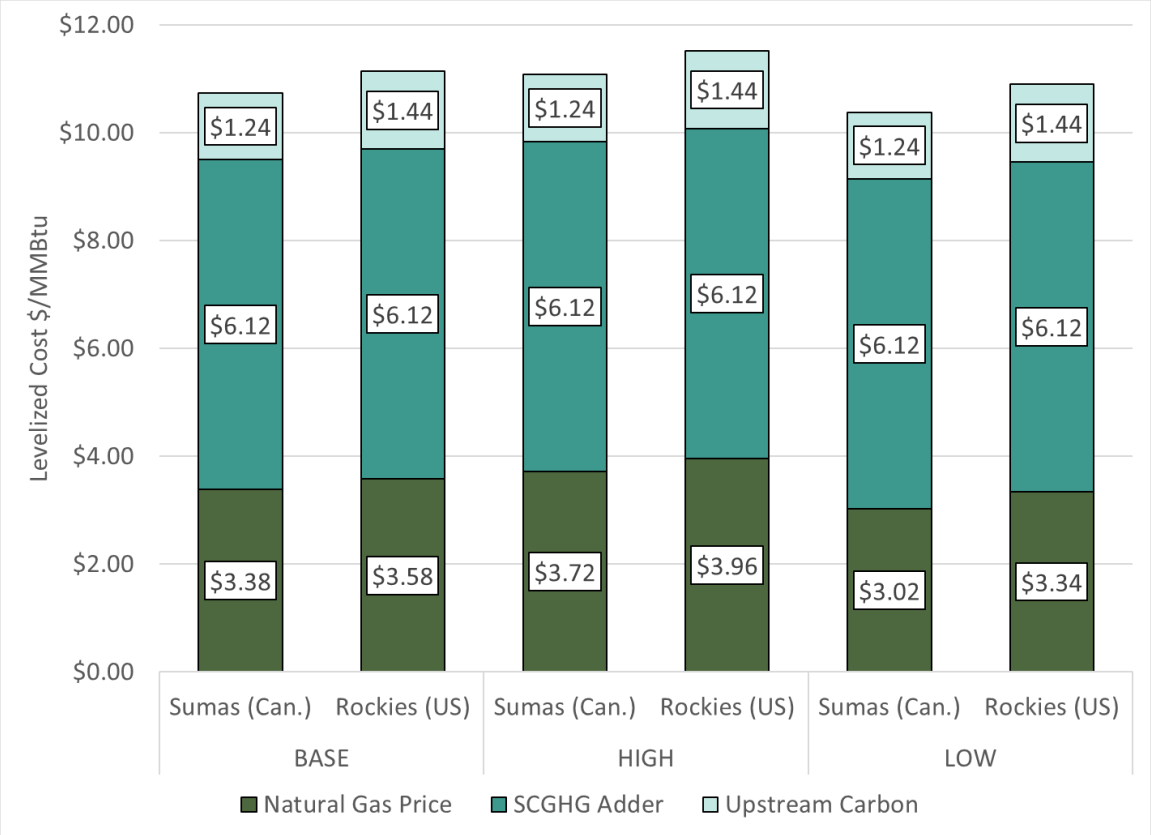
Cost-effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all of the scenarios. The conservation is driven by the total natural gas costs, which now includes additional costs for upstream emissions, more than by other factors such as resource need. Figure 3-26 shows the results of cost-effective DSR for the Mid Scenario with and without the carbon adders, and that the amount of cost-effective DSR is significantly lower when the total cost of natural gas consists of only the natural gas commodity costs.

Figure 3-26: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-27, When the carbon adders are included, the total cost of natural gas varies only slightly from one scenario to the next, and this results in the same level of DSR being selected in all three scenarios.

Figure 3-27: Total Cost of Natural Gas (Commodity + SCGHG + Upstream Emissions)



Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in the High scenario. The timing of the Swarr upgrade is driven by the load forecast. In the High load scenario, Swarr is needed by 2037/38. Upgrades to Swarr are essentially within PSE's ability to control, so PSE has the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, since expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. The Swarr upgrade has a short lead-time, and PSE has the flexibility to adjust it as the future unfolds.

Plymouth LNG

The Plymouth LNG peaker contract was selected as a least cost resource in the High Scenario. The plant is in PSE's electric portfolio, and the contract is up for renewal in April 2023, at which point the natural gas sales portfolio could buy the contract. In the High load scenario, the plant was selected to start service in the 2023/24 winter, and it has an associated pipeline capacity of 15 MDth per day on Northwest Pipeline to deliver the natural gas to PSE.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines north to Station 2 is cost effective in the High Scenario, which adds 21 MDth/day in 2034/35, increasing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model. SENDOUT is a helpful tool, but its results must be reviewed based on judgment, since real-world market conditions and limitations on resource additions are not reflected in the model. The following summarizes key decisions for the resource plan.

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Mid Scenario – the same as in the Low and High Scenarios. Natural gas prices appear to have little impact on DSR, regardless of the load growth forecast. The primary variable that affects the resource decision is the assumption for SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257, which became law during the 2019 legislative session and require the SCGHG adders to be incorporated in the planning analysis as part of capacity expansion decisions. The results show that cost-effective conservation in the Mid Scenario is likely to be a safe decision, since the same level of conservation is cost effective regardless of whether the demand forecast is as low as the 10th percentile in the Low Scenario or as high as the 90th percentile in the High Scenario.

The level of cost-effective DSR found in the deterministic Mid, Low, and High Scenarios is a robust result. The stochastic analysis found this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly. Cost-effective DSR reduced both cost and risk in the natural gas portfolio according to the stochastic analysis. Therefore, the risk of over-building or under-building DSR appears to be low.

Supply-side Resources

The supply-side resources – Plymouth LNG peaker contract, Swarr, and pipeline expansions – represent the High Scenario resource additions. No supply-side resources are needed in the Mid and Low Scenarios. Even in the High Scenario, the only resource needed in the near term is the Plymouth LNG peaker contract. The lead time to acquire this resource contract is short, so no decisions are needed until at least 2022. Swarr and NWP plus Westcoast pipeline additions are needed only in the High Scenario in the back half of the study period, thus no decision will be required in the near term. There will be opportunities to review these resources in future IRP cycles before any decisions are necessary.

4. TECHNICAL MODELING ACTION PLAN

Since the 2017 IRP, PSE has made significant advancements in the analytical tools and methods used, and these advancements have been applied to the 2021 IRP. The improvements are documented throughout this IRP. PSE has also identified several improvements for future IRPs. These are described below.

ELECTRIC RESOURCE PLANNING

1. Adopt winter and summer resource adequacy analyses, and develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.
2. Evaluate the benefits and impacts of the regional resource adequacy program and integrate into PSE's resource planning if appropriate.
3. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
4. Evaluate technology solutions to reduce model run times for the electric portfolio and stochastic models.
5. Continue to refine energy storage modeling.
6. Explore transmission planning optimization tools to help understand the impacts of transmission in electric supply portfolio modeling.

NATURAL GAS RESOURCE PLANNING

1. Evaluate available natural gas portfolio models for long-term resource planning and implement new model for the 2023 IRP.
2. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
3. Evaluate the ongoing use of the existing natural gas peak day planning standard and study the impacts of changing the planning standard.



4 Planning Environment

This chapter reviews the conditions that defined the planning context for the 2021 IRP.

4 Planning Environment

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1. CLEAN ENERGY TRANSFORMATION ACT RULEMAKINGS

Since the passage of the Clean Energy Transformation Act (CETA) in 2019, several state agencies have been engaged in rulemakings to implement key provisions of the statute. These include the following.

1. The Washington Utilities and Transportation Commission (WUTC) – multiple topics, including the IRP, Clean Energy Implementation Plan (CEIP), and Purchase of Electricity rulemakings
2. The Department of Commerce (Commerce) – CETA rulemaking primarily for consumer-owned utilities
3. The Department of Health (DOH) – cumulative impact analysis
4. The Department of Ecology (Ecology) – unspecified emissions rate and energy transformation projects.

Each of these rulemaking efforts is summarized below. At the time of this writing, some topics remain unresolved in rulemaking and await further discussion and development in 2021.

WUTC CETA Rulemakings

The WUTC completed three rulemakings at the end of 2020 to implement CETA: the Energy Independence Act (EIA) Rulemaking, the IRP/CEIP Rulemaking, and the Purchase of Electricity Rulemaking.

EIA RULEMAKING. The EIA rulemaking revises certain provisions of existing EIA rules to align with CETA and defines key terms related to the low-income provisions of CETA in RCW 19.405.120, including “low income,” “energy assistance need” and “energy burden.”

IRP/CEIP RULEMAKING. The IRP/CEIP Rulemaking outlines the timing and processes associated with filing an IRP, a Clean Energy Action Plan (CEAP) and a Clean Energy Implementation Plan (CEIP). Among many other new requirements, utilities are directed to establish equity advisory groups to advise utilities on equity issues, including vulnerable population designation, equity customer benefit indicator development and recommended approaches for compliance with RCW 19.405.040(8) as codified in the rule.

PURCHASE OF ELECTRICITY RULEMAKING. The Purchase of Electricity Rulemaking outlines the timing and expectations for utilities when acquiring resources that are identified as a resource need in the IRP.

In addition, the WUTC anticipates further discussions and policy development in 2021 regarding the following issues through a subsequent Markets Work Group rulemaking as required in RCW 19.405.130 or other rulemakings or policy statements.

- Non-energy benefits and the cost-effectiveness test
- No-coal attestation under CETA
- Natural gas IRP rulemaking per HB 1257
- Policy guidance for implementing Section 12 low-income provisions of CETA
- Interpreting a utility's "use" of electricity to serve customers
- Incorporating DOH's Cumulative Impact Analysis (CIA) into utility planning processes

Department of Commerce CETA Rulemaking

The Department of Commerce (Commerce) is charged with developing rules for implementation of CETA for consumer-owned utilities. Additionally, Commerce is responsible for developing reporting procedures for all utilities, investor-owned and consumer-owned. Commerce published the final rules at the end of 2020.

Department of Commerce CETA Low-income Draft Guidelines and WUTC Low-income Policy Development

In early 2020, the Department of Commerce released draft guidelines to support the low-income reporting requirements that utilities must meet under RCW 19.405.120 (Section 12 of CETA). Utilities provided data related to energy assistance to Commerce pursuant to the guidelines issued on November 13, 2020.

Beginning July 31, 2021, utilities must provide to Commerce a biennial assessment of the following.

- Programs and mechanisms to reduce energy burden, including the effectiveness of those programs and mechanisms for both short-term and sustained energy burden reduction.
- Outreach strategies used to encourage participation of eligible households.
- A cumulative assessment of previous funding levels for energy assistance compared to funding levels needed to meet 60 percent of the current energy assistance need or increasing energy assistance by 15 percent over the amount provided in 2018, whichever is greater, by 2030; and 90 percent of the current energy assistance need by 2050.

This assessment also must include a plan to improve the effectiveness of the assessment mechanisms and strategies towards meeting the energy assistance need.

PSE anticipates that this biennial low-income energy assistance report to Commerce will be used to inform any energy assistance potential assessment that may be required in future IRP cycles.[1]

Department of Health Cumulative Impact Analysis

CETA directs DOH to develop a CIA of the impacts of both climate change and fossil fuels on population health, in order to designate highly impacted communities. The results of the CIA will be used to inform power utilities' planning in the transition towards cleaner energy. While DOH set out to carry out this work collaboratively with robust input from stakeholders through work group meetings and subcommittees, DOH's plans for stakeholder engagement were scaled back in 2020 after the onset of the COVID-19 pandemic. DOH released a final CIA tool in February 2021.

Under CETA, the CIA is an important tool for informing a utility's equity-related assessment in its IRP, as well as informing its Clean Energy Implementation Plans.

1 / See Draft WAC 480-100-620(3)(b)(iii), included as part of the UTC's IRP/CEIP Final Proposed Draft Rules published on December 4, 2020.

Department of Ecology Rulemaking

The Department of Ecology is responsible for adopting rules that provide methods for assigning greenhouse gas emission factors for electricity and establishing a process for determining what types of projects may be eligible as “energy transformation projects” under CETA.

Ecology adopted a new rule on January 6, 2021 that establishes: 1) the default unspecified emissions factor in CETA; 2) a general process for determining eligible energy transformation projects; and 3) a process and requirements for developing standards, methodologies and procedures to evaluate energy transformation projects.

2. TECHNOLOGY CHANGES

Convergence of Delivery System Planning and Resource Planning

Traditionally, the focus of an integrated resource planning process has been to determine the lowest reasonable cost mix of demand- and supply-side resources needed to meet the total projected load and peak needs of its customers with an adequate reserve margin. In Washington state, the planning process is prepared under rules or requirements for an IRP and reviewed by state utility commissions.

The IRP process includes the cost of transmission and distribution infrastructure needed to connect and transmit the power from potential new generation sources; however, planning for the transmission and distribution delivery systems that ensure power can be delivered to end-use customers has traditionally been separate from the IRP process.

A variety of economic, technological and societal factors are changing the electric utility planning process and blurring the historical division between delivery system planning (DSP) and integrated resource planning. These include the increasing affordability of solar generation (including rooftop solar), the maturing of battery storage technology, electric vehicle adoption, advancements in customer management and information about electricity use, and advancements in the management and data systems used to integrate and control distributed energy technologies.

In the future, continued growth of customer solar generation and other distributed energy resources will contribute to meeting the overall resource need but will also lead to power being pushed back to a distribution feeder that was not designed for two-way power flows. This will require PSE to plan and build a grid that is different than today to capture the resource benefit effectively. The grid of the future needs to be safe, reliable, resilient, smart, clean and flexible.

Washington State's Clean Energy Transformation Act is also driving change. It recognizes that transforming the state's energy supply requires the modernization of its electricity system and that clean energy action planning must include any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities. Additionally RCW 19.280.100, resulting from House Bill 1126, furthers this connection as energy supply needs are met through distributed energy resources (DERs). It established a policy that

guides how distributed energy resource planning processes are to occur in order to illuminate the interdependencies among customer-sited energy and capacity resources.

With this backdrop, PSE is in the process of increasing the coordination of delivery system planning with resource planning, as it provides benefits by bringing together solutions to address delivery system challenges while meeting resource needs. With the increasing maturity and feasibility of DERs, delivery system needs may be solved using these non-traditional solutions at local points or in certain areas of the delivery system. If these non-traditional resources decrease load (such as demand response programs) or provide a generation source (such as rooftop solar), they may also provide benefit to the overall energy supply resource portfolio. This creates a natural connection between DSP and energy supply resource planning.

Historically, the two planning processes have occurred on separate timelines. However, DERs installed in sufficient quantity to solve delivery system needs may change the results in the resource planning process, so coordinating the two benefits both processes and analyses.

A coordinated process must accommodate:

- customer-owned resources and electric vehicles
- programs such as distribution automation and demand response
- distributed energy resources
- energy storage
- energy efficiency strategies

In addition to incorporating the cost of transmission and distribution infrastructure, the IRP and DSP processes use some of the same core information in different ways. Data flows from one process to the other at different steps as shown in Figures 4-1 and 4-2.

The confluence of technology, customer adoption, grid integration capability and solution effectiveness will drive the pace of interconnecting the DSP and IRP processes.

Figure 4-1: Data Flows between Delivery System Planning and Integrated Resource Planning

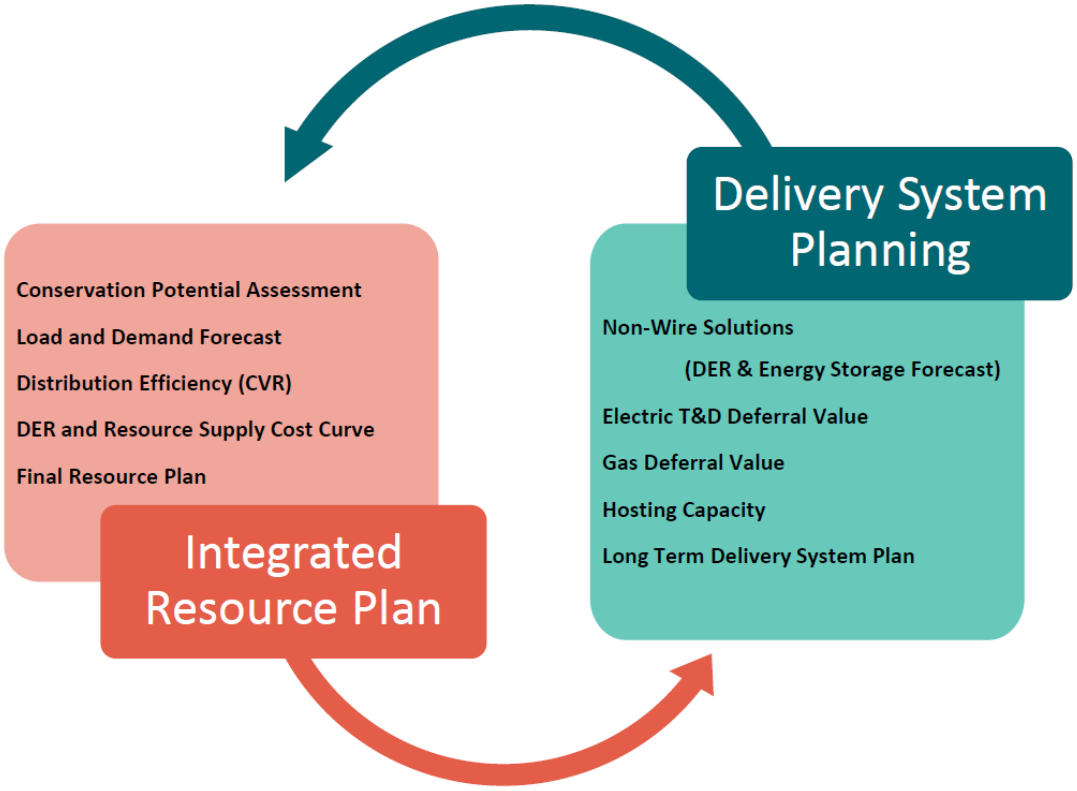


Figure 4-2: Data Flows between Delivery System Planning and Integrated Resource Planning (Table)

IRP Outputs in the DSP	Conservation Potential Assessment	Decreases county-level system capacity needs
	Load and Demand Forecast	Decreases county-level system capacity needs
	Distribution Efficiency (CVR)	Decreases capacity needs where implementable and may be a solution alternative
	DER and Resource Supply Cost Curve	Cost supply curve including different types of DER resources which could be used as non-wire solution alternatives if located appropriately
	Final Resource Plan (including DER's)	Insight for participation in resource acquisition process for DERs to enhance locational value opportunities and informs enabling grid modernization requirements
DSP Outputs in the IRP	Non-wire Solutions (DER & Energy Storage Forecast)	Decreases overall resource need by identifying must-take DER resources to meet specific transmission and distribution delivery needs
	Electric T&D Deferral Value	Provides a quantitative value of past T&D investments to use in the conservation potential assessment
	Gas Deferral Value	Provides a quantitative value of past investments to use in the conservation potential assessment
	Hosting Capacity (future)	Future input for economic opportunities
	Long-term System Delivery Plan	Future input for opportunities and constraints that should be considered

New Fuel Technologies

Renewable Natural Gas

Renewable natural gas (RNG) is pipeline quality biogas that can be used as a substitute for conventional natural gas streams. Renewable natural gas is gas captured from sources like dairy waste, wastewater treatment facilities and landfills. The American Biogas Council ranks Washington 22nd in the nation for methane production potential from biogas sources, with the potential to develop 128 new biogas projects within the state. RNG is significantly higher cost than conventional natural gas; however, it provides greenhouse gas benefits in two ways: 1) by reducing CO_2e emissions that might otherwise occur if the methane and/or CO_2 is not captured and brought to market, and 2) by avoiding the upstream emissions related to the production of the conventional natural gas that it replaces.

RNG is not yet produced at utility-scale in this region and will require developing both supply sources and an infrastructure to deliver that supply to utilities. RNG will most likely be directed toward natural gas utilities before being used as a generation fuel. The electric sector has access to a more mature set of renewable options than the natural gas sector; these include hydro, wind, solar, geothermal and energy storage systems that can capture surplus energy. Natural gas utilities have very few options to decarbonize, so as natural gas utilities begin decarbonizing their systems in earnest, markets will probably pull RNG to natural gas utilities before it is used broadly as generation fuel. Costs remain high to upgrade RNG to gas pipeline specifications and bring it to market. Another obstacle is that RNG currently generated in the U.S. is mostly used as a transportation fuel because of federal and state programs such as the EPA's Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), which provide more value through generating credits than when it is used for end-use consumption or to generate electricity. However, the existing natural gas distribution network can be used to deliver renewable fuel.

HB 1257 became effective in July, 2019, and PSE is working with the WUTC and other stakeholders to develop guidelines to implement its requirements. However, recognizing the competitive nature of the existing RNG market, PSE concluded that there would be an advantage to be a first-mover. To that end, PSE conducted a RFP to determine availability and pricing of RNG supplies. After analysis and negotiation, PSE acquired a long-term supply of RNG from a recently completed and operational landfill project in Washington at a competitive price. PSE is in final design of Tariff provisions and IT enhancements to facilitate availability of a voluntary RNG program for PSE customers to take effect in the first half of 2021. RNG supply not utilized in

PSE's voluntary RNG program(s) will be incorporated into PSE's supply portfolio, displacing natural gas purchases as provided for in HB 1257.

In addition, PSE has a current offering called Carbon Balance which provides residential natural gas customers the choice to purchase blocks of carbon offsets for a fixed price. The program provides customers with a way to reduce their carbon footprint through the purchase of third-party verified carbon offsets from local projects that work to reduce or capture greenhouse gases.

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

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

Biodiesel

Biodiesel is defined 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 similar to petroleum diesel but is derived from waste cooking oil or from dedicated crops. According to the U.S. Energy Information Administration, there are two facilities in Washington state that make biodiesel, which together can manufacture upwards of 100 million gallons of biodiesel a year.[2] Biodiesel may become crucial in the future as a fuel supply for combustion turbines. These units would be the same basic generator as a natural gas combustion turbine, but instead of burning natural gas with petroleum diesel as a backup fuel, the generator would burn renewable natural gas with biodiesel as the backup fuel. Biodiesel may also serve as a primary fuel for combustion turbines intended for strictly peak need events. At full 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 continuously fire for a 48-hour peak event. Existing Washington state biodiesel production could plausibly supply several combustion turbines intended to supply reliable capacity during critical hours. This technology may be crucial to maintaining a reliable, renewable electric system during low hydro conditions.

Biodiesel use in simple-cycle combustion turbines is explored in this IRP. An analysis of the amount of fuel needed is in Chapter 7, Resource Adequacy Analysis, and the results of the portfolio optimization are in Chapter 8, Electric Analysis.

Hydrogen

Renewable hydrogen, also known as power-to-gas, is a process by which excess renewable electricity can be transformed (by splitting hydrogen from water) into hydrogen, or, if combined with carbon, synthetic natural gas. These fuels can then be stored utilizing existing natural gas pipeline infrastructure to more cost effectively shift seasonal supply when mismatched with demand.

PSE is a founding member of the Renewable Hydrogen Alliance (RHA). The RHA promotes using renewable electricity to produce climate-neutral hydrogen and other energy-intensive products to supplant fossil fuel consumption. This group is instrumental in keeping PSE up to date on industry developments.

Hydrogen or its derivatives can be used to reduce the GHG content of gas for gas utilities. Renewable hydrogen can be injected into the existing pipeline infrastructure. The amount of hydrogen that can be blended into the pipeline system with natural gas is limited, because hydrogen is less energy dense than current standards for pipeline quality gas. That means a cubic foot of hydrogen has less energy than a cubic foot of natural gas. Pipeline systems are required to maintain heat content within predetermined ranges for safety reasons. Natural gas-consuming equipment and appliances are designed to use a certain amount of gas per unit of

2 / *https://www.eia.gov/biofuels/biodiesel/capacity/*

time, so the gas feeding that equipment needs to maintain these standards. Currently, it appears the ratio of hydrogen that could be injected into the system is about 20 percent.

Hydrogen can also be used as a fuel in gas combustion turbines – both simple-cycle and combined-cycle plants. The hydrogen can be blended into the upstream natural gas supply and delivered on existing infrastructure, based on the physical safety limits described above for gas utilities. Hydrogen can also be injected directly into combustion turbines or blended in higher ratios than 20 percent, if the hydrogen manufacturing, storage and delivery infrastructure is built.

A significant challenge for hydrogen is cost. Today, gray hydrogen (hydrogen manufactured with fossil fuel energy) sells for about $2 per kilogram delivered to a few key chemical market hubs, which translates to about $17.6 per MMBtu for natural gas.[3] While green hydrogen may use surplus renewable electricity that may cost less on a dollars per MWh basis, the output of a hydrogen manufacturing facility using only surplus renewable energy will be less, which will drive up the average cost per unit.

For this IRP, PSE explored hydrogen as an alternative fuel source for the combustion turbines. Though manufacturers have done extensive development for a hydrogen-fueled combustion turbine, it was difficult to get a price forecast for the fuel. Also, the modeling techniques are not available to model hydrogen as both a storage for renewable energy and a fuel for the combustion turbines. PSE will continue to explore hydrogen as a fuel source for combustion turbines and new modeling techniques for future IRPs.

3 / See S&P Global at: https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867#:~:text=S%26P%20Global%20Ratings%20believes%20hydrogen,and%20massive%20growth%20of%20renewables.&text=A%20Hydrogen%20Council%20report%20suggests,primary%20energy%20supply%20by%202050

3. WHOLESALE MARKET CHANGES

Prices, Volatility and Liquidity / August 2020 Supply Event

Wholesale electricity prices in the Pacific Northwest remain, on average, relatively low. In recent years, however, these relatively low prices have been punctuated by periods of high volatility and limited market liquidity.

On August 17, 2020, in the middle of a heat wave affecting the western U.S., the region's reliability coordinator declared an Energy Emergency Alert for PSE and four other grid operators in the WECC, indicating these entities risked not having sufficient energy supply to meet their load and reliability obligations. Wholesale market dynamics and reliance on energy transfers from neighboring entities were key factors in how this event developed in the Northwest. In the day-ahead market, power prices at the Mid C hub spiked to more than five times what they were just days earlier. Offers to sell power at Mid C disappeared as available supply flowed to even higher priced delivery points in California and the desert southwest. By Monday August 17, 2020, forecasted load had increased with higher temperatures, but additional supply in the Mid C real-time market was extremely scarce. For the highest load hours of the day PSE was unable to procure power at any price. In California, the situation was even more severe, and in the days leading up to August 17, 2020, CAISO implemented rolling black-outs in order to maintain grid stability.

In its report on the August 2020 event, CAISO identifies extreme heat resulting from climate change and the evolving mix of generation resources as primary factors leading to insufficient supply conditions. As extreme temperatures become more common and traditional thermal resources continue to be replaced with variable renewable resources, high price volatility and the risk of unavailable supply are likely to be more prevalent in western U.S. wholesale power markets.



Market Developments / CAISO EDAM

In late 2018, CAISO engaged stakeholders to examine the feasibility of extending participation in its day-ahead market to entities already participating in the energy imbalance market (EIM). Potential benefits of an extended day-ahead market (EDAM) include production cost savings through more efficient use of available transmission, more efficient day-ahead unit commitment, and the creation of day-ahead base schedules at hourly granularity; diversity of imbalance reserves; and environmental benefits including reduced curtailment of renewable resources. EDAM would operate in a framework similar to EIM's approach to the real-time market, which does not require full integration into the California ISO balancing area. Participating entities and their regulatory authorities would remain responsible for transmission planning, resource adequacy and balancing area control performance.

A feasibility assessment completed near the end of 2019 identified significant benefits associated with the EDAM proposal, and stakeholder entities have since started work on more specific market design criteria. Evaluation of topics including governance, resource sufficiency requirements and the distribution of market benefits has been ongoing throughout 2020, and a final market design proposal is expected in late 2021.

4. REGIONAL RESOURCE ADEQUACY

Utilities across the Northwest have partnered to explore a potential regional resource adequacy program. Resource planning in the Northwest is currently done on a utility-by-utility basis, typically through integrated resource planning processes. This utility-by-utility planning framework has worked well for the region during times when the region was surplus capacity. As large amounts of firm generators retire and several regional studies point to a capacity deficit in the next decade, utilities have growing concerns about whether the new capacity needed to maintain regional reliability can be procured in a timely manner. A Northwest resource adequacy program would offer two key benefits: reliability and cost savings. First, a regional resource adequacy program would ensure that sufficient generation is available to reliably serve demand during periods of grid stress. Resource adequacy programs do this by establishing transparent processes to assess, allocate and procure a region's resource needs. Second, a regional resource adequacy program would enable cost savings. By planning for the peak demand of the entire region (the coincident peak demand) instead of each utility's individual (non-coincident) peak demand, a regional approach would produce an overall lower capacity need and therefore a reduced level of investment. Furthermore, larger systems tend to require lower reserve margins because they are less vulnerable to single contingencies and variation in supply and demand.

Resource adequacy programs deliver these benefits by establishing transparent, coordinated calculations of required capacity and offering mechanisms for sharing resources among participants. A resource adequacy program in the Northwest would help the region navigate reliability and cost challenges given its evolving resource mix.

In late 2019, NWPP members initiated a resource adequacy program design development process. In mid-2020, the NWPP Resource Adequacy Program Conceptual Design was completed and Southwest Power Pool (SPP) was hired to lead the detailed design in partnership with the NWPP members. At the time of this writing, the detailed design is underway, and the process is expected to conclude in mid-2021. The timeline for the overall resource adequacy program implementation is estimated to be in 2024. PSE is actively involved in the design development process and looks to leverage program benefits. Future IRPs will need to incorporate the RA program into its resource adequacy analysis and overall planning process.

5. FUTURE DEMAND UNCERTAINTY FACTORS

Electric Vehicles

Electric vehicles (EVs) are rapidly gaining a presence in PSE's service territory and taking hold in every vehicle market. These EVs include light-duty vehicles, medium-duty vehicles, and heavy-duty vehicles, both cars and trucks, and they are operated by individuals and as members of fleets. EVs create new electric load, and the pace and scale of EV adoption is key to the magnitude of these impacts on utility demand. PSE contracted for an EV sales and load forecast, which was then incorporated into the 2021 IRP Demand Forecast. This forecast revealed new opportunities to manage EV load and improve customer experience, which PSE is investigating through a suite of EV pilot programs.

The 2021 IRP Base Demand Forecast incorporates GuideHouse's incremental EV energy forecast by excluding demand from existing vehicles. See Chapter 6, Demand Forecasts, for a discussion of base energy demand and peak impacts.

Demand Impacts

The Electric Vehicle Charger Incentive (EVCI) Pilot Program, which went into effect on May 1, 2014, allowed PSE to offer a $500 rebate to customers who purchase their own Level 2 electric vehicle charger.[4] Using data gathered through this pilot, PSE created an "Electric Vehicle Household and Charger Load Profiling" study with a study period set for 12 months ending June 2017. At the time, there were an estimated 13,140 EVs registered in PSE's electric service territory, of which 9,480 were 100 percent battery-operated (BEV) and 3,660 were plug-in hybrid vehicles (PHEV).[5]

The key findings of the study were as follows:

- On a typical weekday, hourly load per Level 2 EV charger varied between 0.1 kW and 0.9 kW while hourly load per Level 1 charger ranged between 0.06 kW and 0.6 kW.[6]
- On a typical weekend day, hourly load per Level 2 charger ranged between 0.08 kW and 0.6 kW while the range of hourly load per Level 1 charger was 0.04 kW to 0.5 kW.

4 / Docket UE-131585
5 / A list of EV's registered through the end of June 2017 was provided by Washington State Department of Licensing.
6 / The average hourly load per EV charger should not be interpreted as the hourly energy use by a typical EV charger. For example, a typical Level 2 charger uses between 1.1 kW and 2.6 kW while in use and close to zero while not in use. An individual L2 charger load shape would be characterized by a flat load at nearly zero kW for most of the day interrupted by one or more charging events which last a few hours or so per event.

- Daily peak of EV charger load occurred mostly in the early evening hours of 6:00 PM to 8:00 PM, as does monthly system peak demand.
- Monthly load factor and system coincidence factor of EV charger loads are fairly low for most months. During the study period, all of the monthly load factors were below 0.29 while 8 of 12 monthly system coincidence factors were lower than 0.40. However, the system coincidence factor will become very high if monthly system peak and EV charger peak loads occur on the same day, as happened in March 2017 when the system coincidence factor was 0.91.

Although at the time of this study EVs represented a very small portion of the residential class load, PSE predicts that by 2032 there will be more than 250,000 Light Duty EVs in PSE's service territory.

To study the implications of this growing load that can be added anywhere and potentially coincident with peak, PSE's Up & Go Electric programs are actively working to develop load shapes for additional charging use cases that are specific to PSE's electric service territory. This suite of pilot programs is expanding to include workplace charging, multi-unit dwellings, public charging, many unique low-income use cases, a more refined load profile for single-unit dwelling charging, and to capture a broader audience for each of these use cases. The programs will also develop load profiles for prominent medium and heavy duty vehicle charging use cases.

In addition to developing load shapes, a key goal of PSE's Up & Go Electric program is to investigate the most effective and efficient ways of encouraging and enabling EV customers to shift charging to off-peak hours in a way that minimizes demand-side impacts. These programs are ongoing and final results are not yet available, but PSE has already applied some of the early lessons learned to the design of future programs to ensure that customer load is managed not only to reduce coincidence with system peak, but also to minimize the coincidence of charging between EV chargers.



Energy Efficiency Technology, Codes and Standards and Electrification

Changing codes and standards and energy efficiency technology are impacting both customer choices and energy efficiency programs.

In terms of energy efficiency programs for example, when federal minimum lighting performance standards included screw-in LED lighting, this removed LEDs from energy efficiency program offerings; while LEDs continue to achieve savings, they could no longer be included in incentive programs.

The two energy codes that impact PSE customers, the Washington State Energy Code (WSEC) and the Seattle Energy Code, are transitioning to include a focus on carbon emissions in addition to energy efficiency, and these changes emphasize electrification of systems formerly fueled by natural gas. Since 2018, the WSEC no longer gives builders efficiency credits for new single family homes that install natural gas space heating or water heating, instead giving them credits for installing heat pumps for space and water. In 2021, the Seattle Energy Code put significant barriers on using natural gas for space and water heating in new commercial and multi-family buildings. With few exceptions, new buildings will be using various types of heat pump technology to attempt to meet the loads of these systems.

While technology continues to provide innovation in how loads are met in customer homes and buildings, it takes time for these changes to gain significant market penetration. Heat pump water heaters, for example, have been on the market for nearly a decade, but they are largely limited to the new home market rather than the much larger existing home market. When code changes move quickly, adoption issues arise and may include: the lack of robust examples/applications that have validated particular approaches (such as the sole use of heat pumps to serve both space and water heating in large-demand applications, essentially new building electrification); the complexity of the design, operation and maintenance of systems that have been largely hands-off traditionally; and the installer community not being fully prepared to transition to installing and maintaining these systems. Time is required to work out design flaws, build trust in the installer/trades community, and drive down costs so that consumers will pay reasonable costs to make these changes.

Despite how quickly changes are taking place in the areas of technology and codes and standards, PSE remains committed to ensuring its customers are made aware of the

opportunities to reduce energy use and carbon footprints, advocating for smart changes to codes and standards and working with our trade allies to understand and mitigate barriers to new technology adoption.

Distributed Energy Resources

DER-based generation, such as rooftop solar panels, has seen price declines and increases in customer adoption. The technology and its rate of adoption are still evolving, and therefore future demand can be significantly impacted by policy, including incentives, and technological advances, including further price declines.

While PSE customer adoption of DER is low when compared to states like California and Hawaii, PSE residential solar is increasing by about 2,000 customers annually. Additionally, the average capacity of residential solar is increasing. In 2009, the average residential capacity was 4.7 kW, while the current average system generating capacity is 10 kW. As of the end of 2020, PSE's system hosted 85 MW of net metered solar, with over 10,100, or about 1 percent, of customers participating. In comparison, solar represents about 25 percent of Hawaii's generation capacity and over 10 percent of its residential customers have solar generation.

Adding increasing volumes of DERs to the distribution system, whether they are generating technologies such as solar, storage technologies such as batteries, or load management tools, requires rethinking how the distribution system operates and what standards and controls are needed to maintain the safety and reliability of the system. Demand will be impacted by when and how these technologies operate, whether dependably and reliably decreasing load or intentionally increasing load if charging is allowed during peak hours.

Additionally, most customers pursing DER solutions today do not consume all of the energy they generate on-site in real time, making demand and power flow more variable on the local distribution system and resource management overall. Storage and control systems promise improvement in managing DERs' benefits and impacts on demand, and over 4 percent of PSE's net metered solar installations include battery storage today. These emerging capabilities are maturing, and as monitoring, control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to understand real demand impacts will increase.

For this IRP, PSE explored and modeled numerous future DER options; these are documented in Chapters 5 and 8.

6. NATURAL GAS SUPPLY AND PIPELINE TRANSPORTATION

Risks to Natural Gas Supply

Natural gas is imported to the Pacific Northwest, primarily from British Columbia and the Rocky Mountain region. Disruptions to natural gas transportation infrastructure, therefore, present a risk to reliable gas supply in the region.

In October 2018 the Westcoast Pipeline, a major pipeline that brings natural gas from British Columbia south to the U.S. border, ruptured, severely limiting the supply of natural gas to the Pacific Northwest. Through a combination of immediate conservation efforts, the shutdown of natural gas fired power plants, and curtailment of service to select industrial customers, the region only narrowly avoided destabilization of the natural gas transportation system and curtailment of service to large swaths of natural gas customers.

Capacity restrictions on the Westcoast Pipeline continued well into 2019 causing a dramatic increase to wholesale natural gas prices in the region. By late 2019, the pipeline had been restored to normal full capacity, and while average gas prices have generally returned to pre-event levels, prices remain significantly more volatile compared to recent historical periods.

The lessons learned from the October 2018 event were applied in the restructured Northwest Mutual Assistance Agreement (NWMAA). The Agreement is made among entities that utilize, operate and control natural gas transportation and/or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada and Idaho). The Agreement[7] is intended to define the terms and conditions for cooperation and/or assistance between the parties in an emergency if such aid is volunteered. Another objective is to maintain and improve communication linkages between the members as they pertain to emergency planning and incident response.

7 | https://www.westernenergy.org/nwmaa/

7. PURCHASING VERSUS OWNING ELECTRIC RESOURCES

The IRP determines the supply-side capacity, renewable energy and energy need which set the supply-side targets for future detailed planning in the Clean Energy Implementation Plan, as well as the acquisition process. The formal Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and resource build decisions should also be considered when making prudent resource acquisition decisions.

In Build versus Buy, “Build” refers to resource acquisitions that involve PSE ownership of an asset. Ownership could occur anywhere along the development life cycle of a project. PSE could complete development activities from the beginning or buy the asset anywhere from early stage development to Commercial Operation Date (COD) or after. “Buy” refers to purchase of the output of a project through a Power Purchase Agreement (PPA).

In general, quantitative and qualitative evaluations for Build and Buy proposals are conducted similarly in an RFP, consistent with WAC 480-107, solving for the lowest cost options for customers. Qualitative project risks are evaluated in the same way for both kinds of acquisitions. Quantitative evaluations for Build options include costs of ownership such as operating expenses and depreciation. These are typically embedded in the MWh price for PPAs. Build proposals include the allowable rate of return on capital assets as a cost to customers, while Buy proposals include a return on the PPA costs as allowed by the Clean Energy Transformation Act. Project designs also need to be more carefully scrutinized for projects that PSE would own and operate. Equipment selection and design specifications must meet PSE standards for ownership.

In the 2018 RFP, PSE received a large number of ownership proposals. These proposals included offers for PSE to take ownership of projects before COD, at COD and after COD. Primarily because of the fact that PSE cannot monetize federal tax incentives for renewable projects, these proposals were not competitive relative to PPAs.



5 Key Analytical Assumptions

This chapter describes the forecasts, estimates and assumptions that PSE developed for this IRP analysis; the scenarios created to test how different sets of economic conditions affect portfolio costs and risks; and the sensitivities used to explore how different resources or environmental regulations impact the portfolio.

5 Key Analytical Assumptions



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- *Electric Portfolio Sensitivities*

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- *Natural Gas Scenarios*
- *Natural Gas Scenario Inputs*
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- *Natural Gas Portfolio Sensitivities*

1. OVERVIEW

This chapter describes the forecasts, estimates and assumptions that PSE developed for the electric and natural gas IRP analysis. The details of the electric and natural gas analyses can be found in Chapters 8 and 9, respectively, and further details are available in various appendices.

Section 2, Electric Analysis, presents the electric scenarios created to test how different sets of economic conditions affect portfolio costs and risks, followed by the inputs used to create those scenarios. Scenario inputs include the IRP demand forecast; price assumptions for natural gas and CO_2 costs; assumptions about cost and characteristics for existing and generic resources; and transmission considerations.

Electric portfolio sensitivities are described next. Sensitivities start with the optimized, least cost Mid Scenario portfolio produced in the scenario analysis and change a resource, environmental regulation or other condition to examine the effect of that change on the portfolio. PSE analyzed 27 sensitivities for the electric analysis.

Section 3, Natural Gas Analysis, is organized similarly. The natural gas scenarios are described first, followed by the inputs used to create the scenarios, then the sensitivities used to examine the effects of changes on the Mid Scenario portfolio. PSE analyzed six sensitivities for the natural gas analysis.

Each section also describes the delivery system planning assumptions for its respective energy delivery system.

Time horizon: The time horizon for the 2021 IRP is 2022 – 2041. The natural gas analysis analyzes the time frame 2022 – 2041, but the electric analysis has been expanded to analyze the time frame 2022 – 2045 to better understand the implications of CETA.

2. ELECTRIC ANALYSIS

Electric Price Forecast Scenarios

PSE created three scenarios for the electric analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources. PSE also added two scenarios to test how different carbon pricing can impact electric prices. The five electric price scenarios are outlined in Figure 5-1 and summarized below. A description of the economic inputs to the scenarios follows.

Figure 5-1: 2021 IRP Electric Price Forecast Scenarios

	Scenario Name	Demand	Natural Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation
1	Mid	Mid[1]	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
2	Low	Low	Low	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
3	High	High	High	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC
4	SCGHG as Dispatch Cost	Mid	Mid	Social cost of greenhouse gasses modeled as federal CO_2 price across the WECC	Washington CETA, plus all regional RPS regulations in the WECC
5	CO_2 tax	Mid	Mid	CO_2 Regulation: Social cost of greenhouse gases included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: $15/ton in 2022 increasing at $10/year across the WECC	Washington CETA, plus all regional RPS regulations in the WECC

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

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[1] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[2] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

1 / *https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf*

2 / *WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.*

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in the region and in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a low demand forecast for the WECC, the difference between the low and medium demand forecast in the Pacific Northwest from the NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 3: High

This scenario models more robust long-term economic growth than the Mid Scenario, which produces higher customer demand in the region and in PSE's service territory.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.
- Electric power price modeling: To extrapolate a high demand forecast for the WECC, the difference between the high and medium demand forecast in the Pacific Northwest from NPCC 2019 Policy Update to the 2018 Wholesale Electricity forecast is applied to the WECC region medium forecast.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices for California are included.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

Scenario 4: SCGHG as Dispatch Cost

The social cost of greenhouse gases (SCGHG) as Dispatch Cost Scenario models a federal CO_2 tax that effects all WECC states. This electric price forecast will be used for portfolio sensitivity J, SCGHG as a Dispatch Cost in Electric Prices and Portfolio.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[3] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a CO_2 price across all WECC states.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[4] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

3 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

4 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.

Scenario 5: CO_2 Tax

The CO_2 tax scenario models a federal CO_2 tax plus the SCGHG adder for Washington. This electric price forecast will be used for portfolio sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[5] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE AND REGULATIONS

- The social cost of greenhouse gases is expressed as a cost adder for resources in Washington or delivered to Washington.
- For natural gas generation fuel, upstream CO_2 emissions are added to the emission rate of natural gas plants in PSE's portfolio model.
- CO_2 prices applied to all WECC states.

CLEAN ENERGY AND RPS REGULATIONS

- For Washington state, at least 80 percent of electric sales (delivered load) are met with non-emitting/renewable resources by 2030 (per CETA) and 100 percent by 2045; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC[6] are applied. See further discussion on methodology in Appendix G, Electric Analysis Models.

5 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

6 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting electric service reliability in the western United States.

Comparison Electric Price Scenario for CETA Rate Impact Cost Control

The rate impact cost controls in the Clean Energy Transformation Act (CETA) are calculated based on incremental costs associated with CETA compliance. Because a comparison to the base assumptions without CETA is required to estimate these incremental costs, PSE also developed a version of the Mid Scenario that does not include CETA. This electric price scenario will be used for the two cost comparison sensitivities without CETA described in Figure 5-26.

Figure 5-2: Comparison Electric Price Scenario for CETA Rate Impact Cost Control

COMPARISON SCENARIO FOR CETA RATE IMPACT COST CONTROL					
	Scenario Name	Demand	Gas Price	CO_2 Price	RPS/Clean Energy Regulations
	Mid + No CETA	Mid[1]	Mid	CA AB32 CO_2 policy	RCW 19.285, plus all regional RPS regulations in the WECC

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

Mid + No CETA

This scenario is for comparison purposes only; it is not part of the resource plan.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.
- For electric power price modeling, the Northwest Power and Conservation Council (NPCC) 2019 Policy Update to the 2018 Wholesale Electricity Forecast[7] is applied.
- The regional mid demand forecast is applied to the WECC region.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- CO_2 prices for California are included.

CLEAN ENERGY/RPS REGULATIONS

- Per RCW 19.285, 15 percent of Washington state energy is supplied by renewable resources by 2020; plus, all other renewable portfolio standards (RPS) and clean energy regulations in the WECC are applied.

7 / https://www.nwcouncil.org/sites/default/files/2019_0611_p4_forecast.pdf

Electric Scenario Inputs

PSE Customer Demand

The 2021 IRP Base, Low and High Demand Forecasts used in this analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period.[8] Significant inputs include the following.

- information about regional and national economic growth
- demographic changes
- weather
- prices
- seasonality and other customer usage and behavior factors
- known large load additions or deletions

Figure 5-3 and Figure 5-4 below show the electric peak demand and annual energy demand forecasts without including the effects of conservation. The forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at Sea-Tac airport.

Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs to be developed. By the time the IRP is completed, PSE may have updated its demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

> > > *See Chapter 6, Demand Forecasts,* *for detailed discussion of the demand forecasts, and* ***Appendix F, Demand Forecasting Models,*** *for the analytical models used to develop them.*

8 / For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but in reality, demand grows faster in some parts of the service territory than others.

Figure 5-3: 2021 IRP Electric Peak Demand Forecast – Low, Base (Mid), High

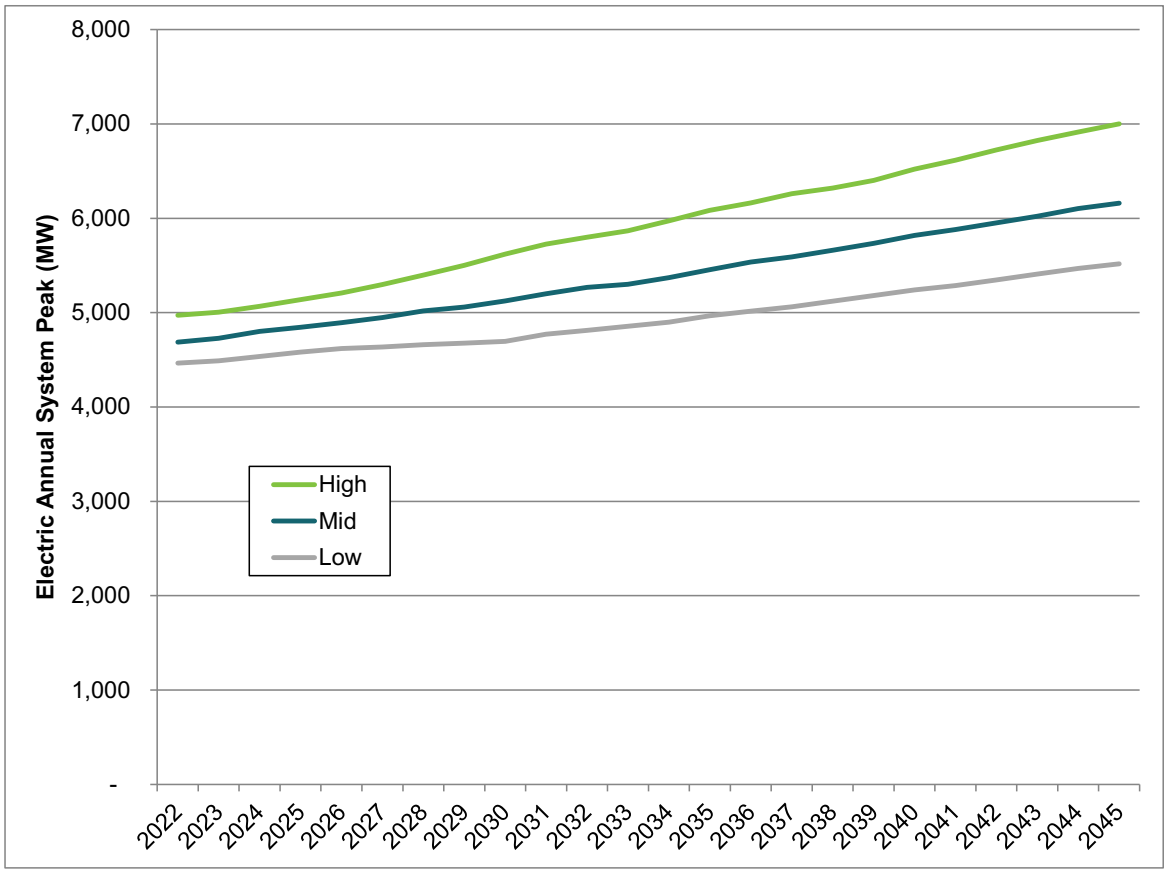
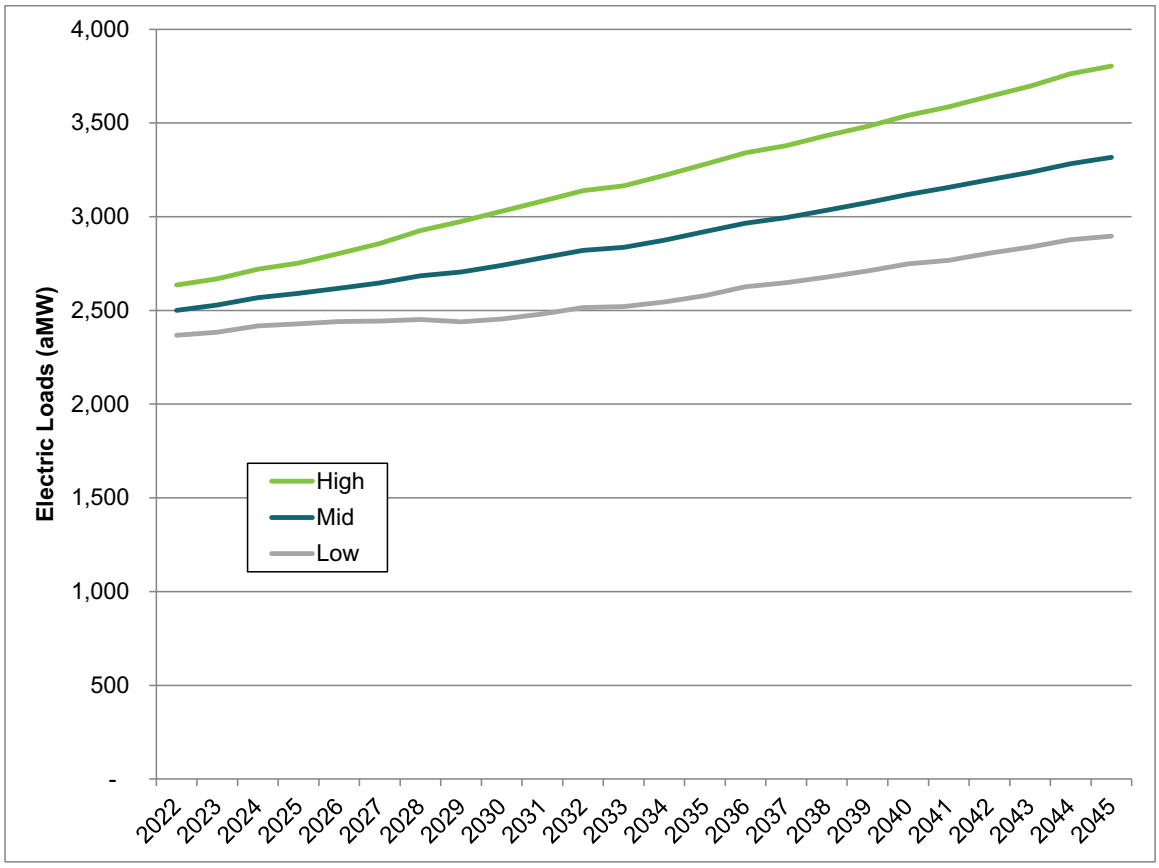


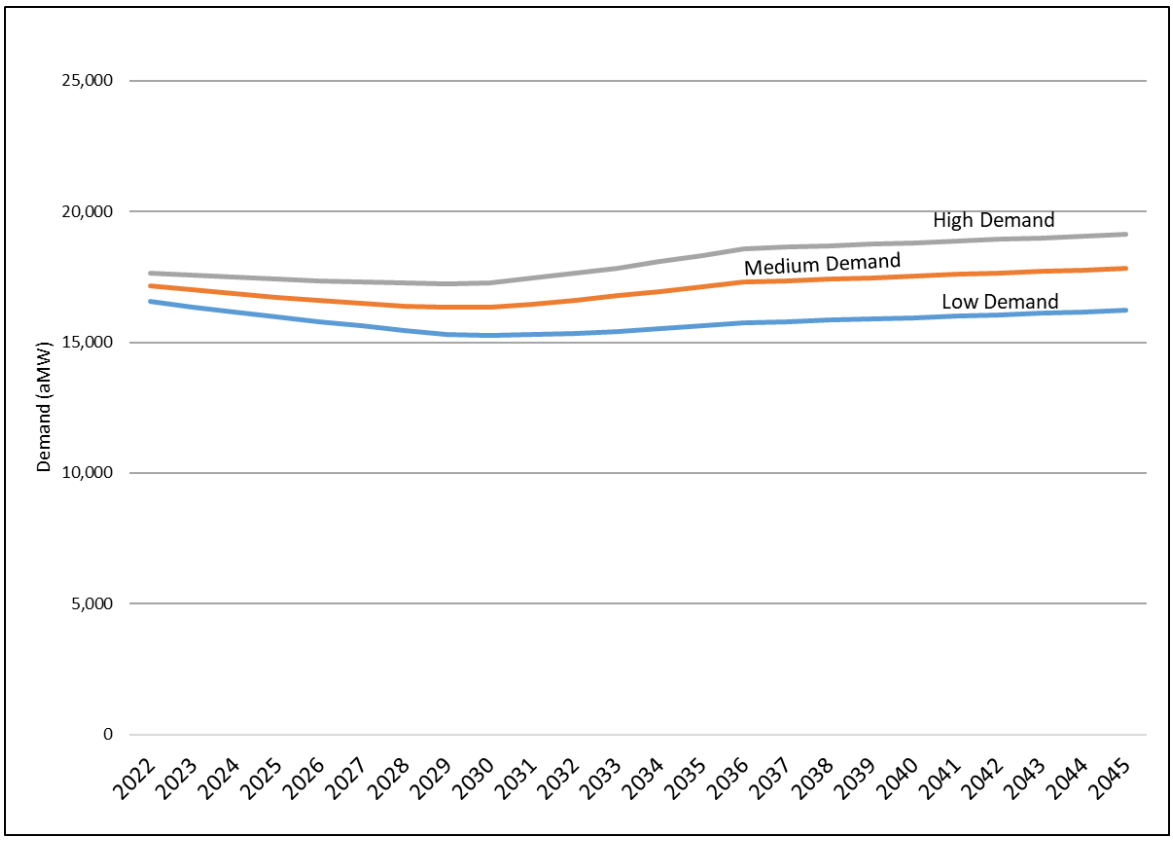
Figure 5-4: 2021 IRP Annual Electric Energy Demand Forecast - Low, Base (Mid) High



Regional Electric Demand

Regional demand must be taken into consideration because it significantly affects power prices. This IRP uses the regional demand developed by the NPCC[9] 2019 Policy Update to the 2018 Wholesale Electricity forecast, the most recent forecast available at the time of this analysis. Updated 2020 loads and COVID-19 impacts were not available from the NPCC until February 2021. Regional demand is used only in the WECC-wide portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 5-5: NPCC Regional Demand Forecast for the Pacific Northwest – Average, not Peak



9 / The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.

Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[10] from Wood Mackenzie.[11]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the one of the Wood Mackenzie long-run natural gas price forecasts published in July 2020.

For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

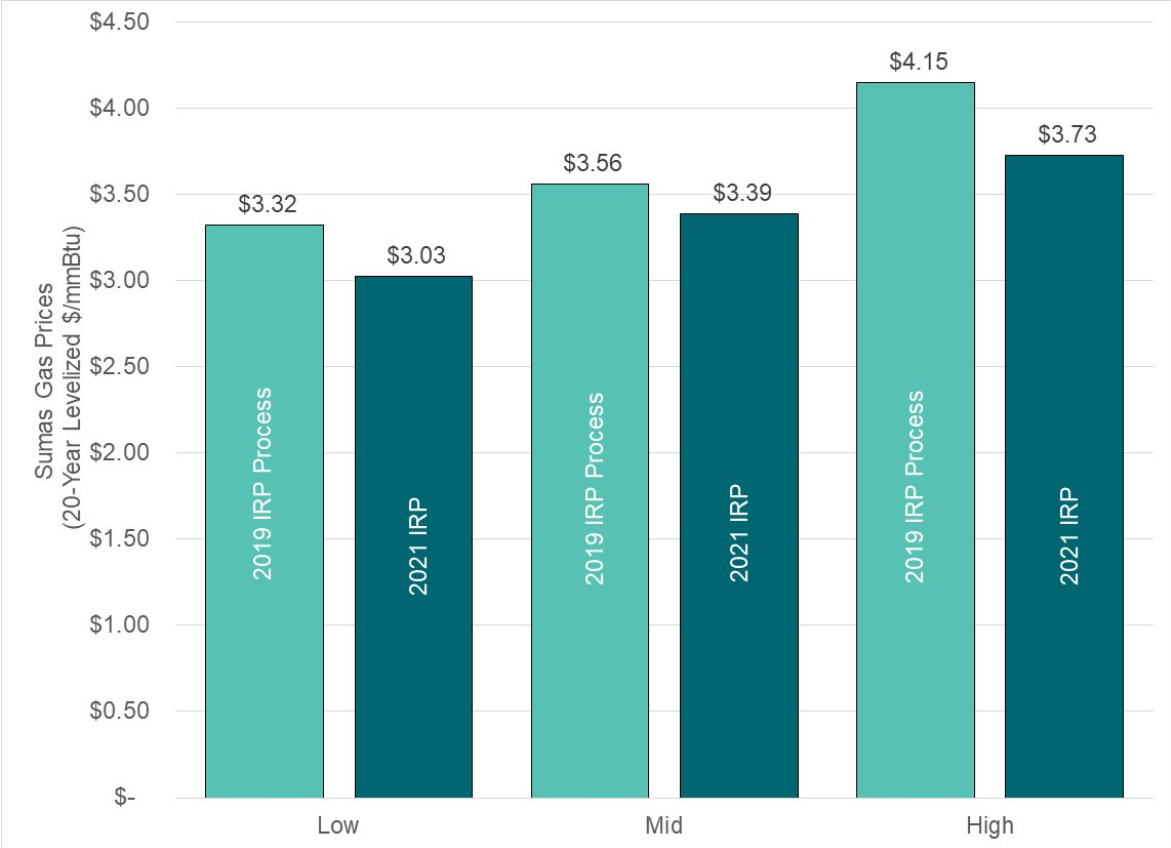
LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

10 / *The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.*
11 / *Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.*

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-6 below illustrates the range of 20-year levelized natural gas prices used in this IRP analysis compared to the 20-year levelized natural gas prices used in the 2019 IRP Process.

Figure 5-6: Levelized Natural Gas Prices Used in Scenarios, 2021 IRP vs. 2019 IRP Process
(Sumas Hub, 20-year levelized 2022-2041, nominal $)



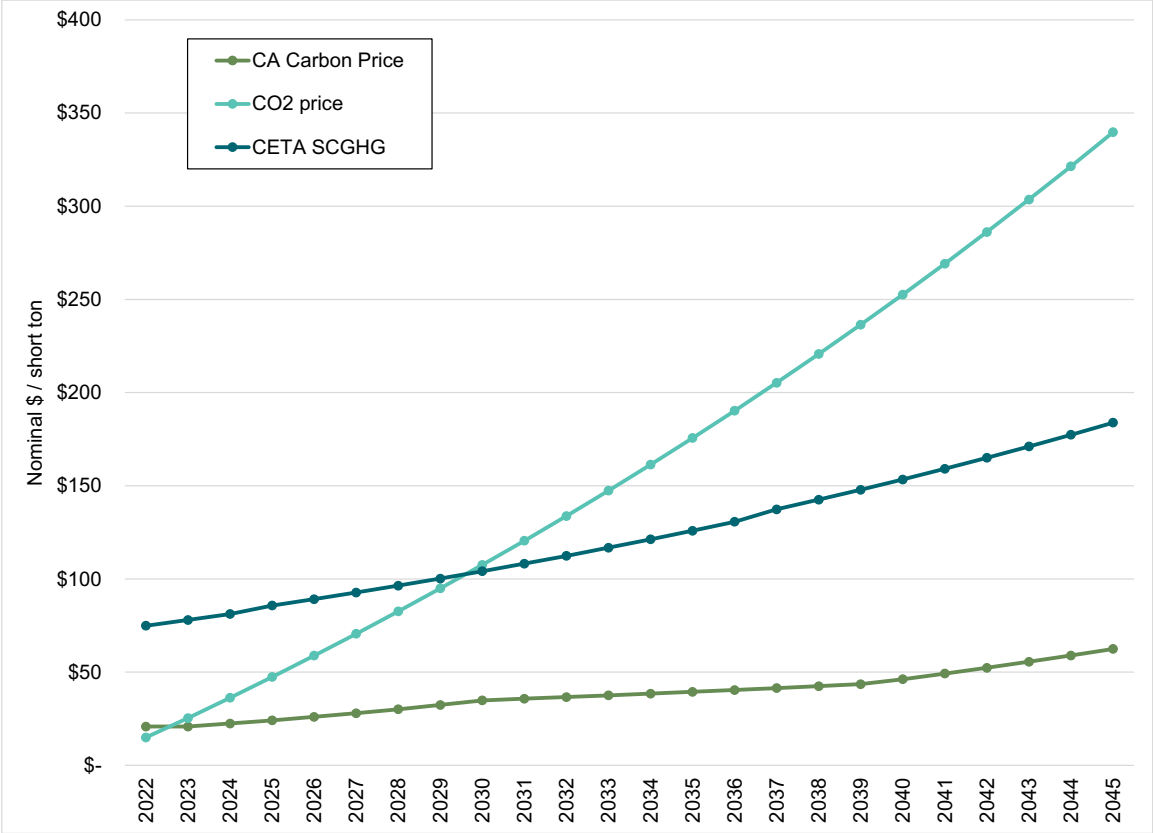
CO_2 Price Inputs

The electric analysis modeled the social cost of greenhouse gases (SCGHG) cited in the Washington Clean Energy Transformation Act (CETA) as a cost adder to thermal resources in Washington state. In addition to the SCGHG mandated by CETA, the analyses modeled the costs imposed by existing CO_2 regulations in California and British Columbia.

SOCIAL COST OF GREENHOUSE GASES (SCGHG). The SCGHG cited in CETA comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the *CO_2* prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $189 per ton in 2045,** as shown in Figure 5-7.

CO_2 tax. The CO_2 tax modeled in this IRP is based on HR763 Energy Innovation and Carbon Dividend Act of 2019. The cost starts at $15 per ton and increases at $10 per year, as shown in Figure 5-7.

Figure 5-7: Social Cost of Greenhouse Gases Used in the 2021 IRP



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[12]

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[13] (PSCAA). PSCAA used two models to determine these rates, GHGenius[14] and GREET.[15] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-8: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/mmBtu and then applied to the emission rate of natural gas plants.

12 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.
13 / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019
14 / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/
15 / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

Renewable Portfolio Standards (RPS) and Clean Energy Standards

Renewable portfolio standards and clean energy standards currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington State RCW 19.285). Each state's requirements are applied to the state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing renewable resources are accounted for, they are subtracted from the total WECC RPS need, and the net RPS need is added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet RPS need. Technologies modeled included wind and solar.

WASHINGTON CLEAN ENERGY TRANSFORMATION ACT (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state must be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. For the 2021 IRP, PSE reviewed the Washington Department of Commerce fuel mix report. For utilities that are currently more than 80 percent hydro, it was assumed that they will reach 100 percent by 2030 and for utilities that are less than 80 percent hydro, it was assumed they will reach 80 percent by 2030. This broke down to 52 percent of sales in Washington met by utilities that will reach 100 percent by 2030 and 48 percent of sales in Washington from utilities that will reach 80 percent by 2030. This averaged to the assumption that 90 percent of sales in Washington will be met by renewable resources by 2030.

Figure 5-9: RPS Assumptions Modeled for Each State in the 2021 IRP

State	State Legislation	RPS/Clean Energy Standards modeled in 2021 IRP
Arizona	Ariz. Admin. Code §14-2-1801 et seq.	15% by 2025
California	SB 100	2024: 44% of retail sales must be renewable or carbon-free electricity 2027: 52% of retail sales must be renewable or carbon-free electricity 2030: 60% of retail sales must be renewable or carbon-free electricity 2045: 100% of retail sales must be renewable or carbon-free electricity
Colorado	SB 263	2020: 30% of its retail electricity sales must be clean energy resources. 2050: for utilities serving 500,000 or more customers, 100% clean energy sources by 2050, so long as it is technically and economically feasible and in the public interest.
Idaho	None	N/A
Montana	SB 164	15% by 2015
Nevada	SB 358	22% for calendar year 2020 24% for calendar year 2021 29% for calendar years 2022 and 2023 34% for calendar years 2024 – 2026 42% for calendar years 2027 – 2029 50% for calendar year 2030 and every year thereafter (must generate, acquire or save electricity from renewable energy systems) GOAL (not an RPS standard): 100% zero carbon dioxide emission resources by 2050.
New Mexico	SB 489	40% renewable resources by Jan 1, 2025 50% renewable resources by Jan 1, 2030 80% renewable resources by Jan 1, 2040 100% zero carbon resources by Jan 1 2045
Oregon	SB 1547	Large investor-owned utilities: 50% by 2040 Large consumer-owned utilities: 25% by 2025 Small utilities: 10% by 2025 Smallest utilities: 5% by 2025
Utah	SB 202	20% by 2025 (GOAL)
Washington	SB 5116	100% of sales to be greenhouse neutral by 2030 – 80% must be met by non-emitting/renewable resources State Policy: 100% of sales met by non-emitting/renewable resources by 2045
Wyoming	None	N/A

The electric portfolio model assumes that PSE will meet the requirement of 80 percent of sales by 2030 and 100 percent of sales by 2045. Starting with PSE's 40 percent in 2020, the model assumes a linear trajectory to 80 percent by 2030 and then another linear incline to 100 percent by 2045.

Power Price Inputs

To complete the scenarios and prepare them for portfolio modeling, PSE must create wholesale power prices for each scenario, because the different sets of economic assumptions create different future power market conditions. In this context, "power price" does not mean the rate charged to customers, it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the four scenarios. (AURORA is an hourly chronological price forecasting model based on market fundamentals.) The AURORA database starts with inputs and assumptions from the Energy Exemplar 2018 v1 database. PSE then includes updates such as regional demand, natural gas prices, gas pipeline adders, variable operations and maintenance, CO_2 prices, RPS need, and resource retirements and builds. Figure 5-10 shows the four power prices produced by the four scenario conditions.

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop wholesale power prices.*

>>> See Appendix H, Electric Analysis Inputs and Results, *for the results of the AURORA capacity expansion run.*

Figure 5-10: Input Power Prices by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)

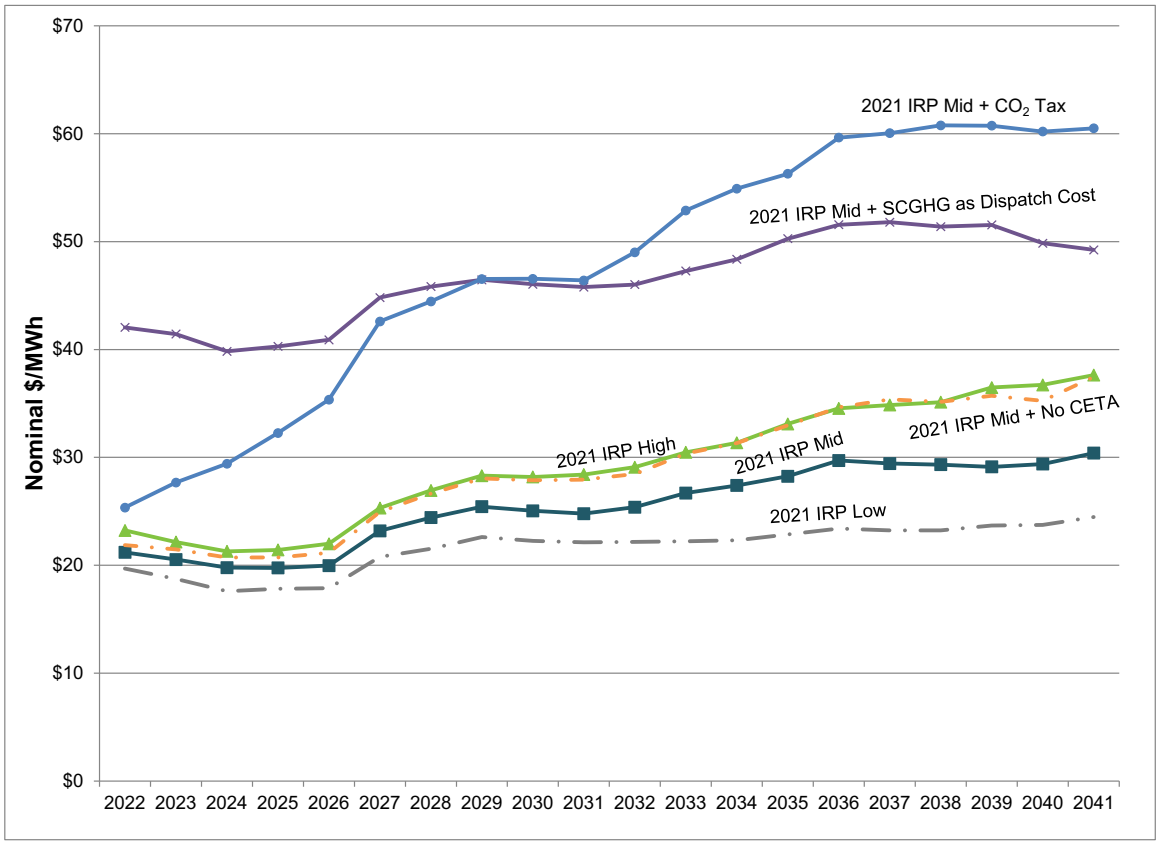
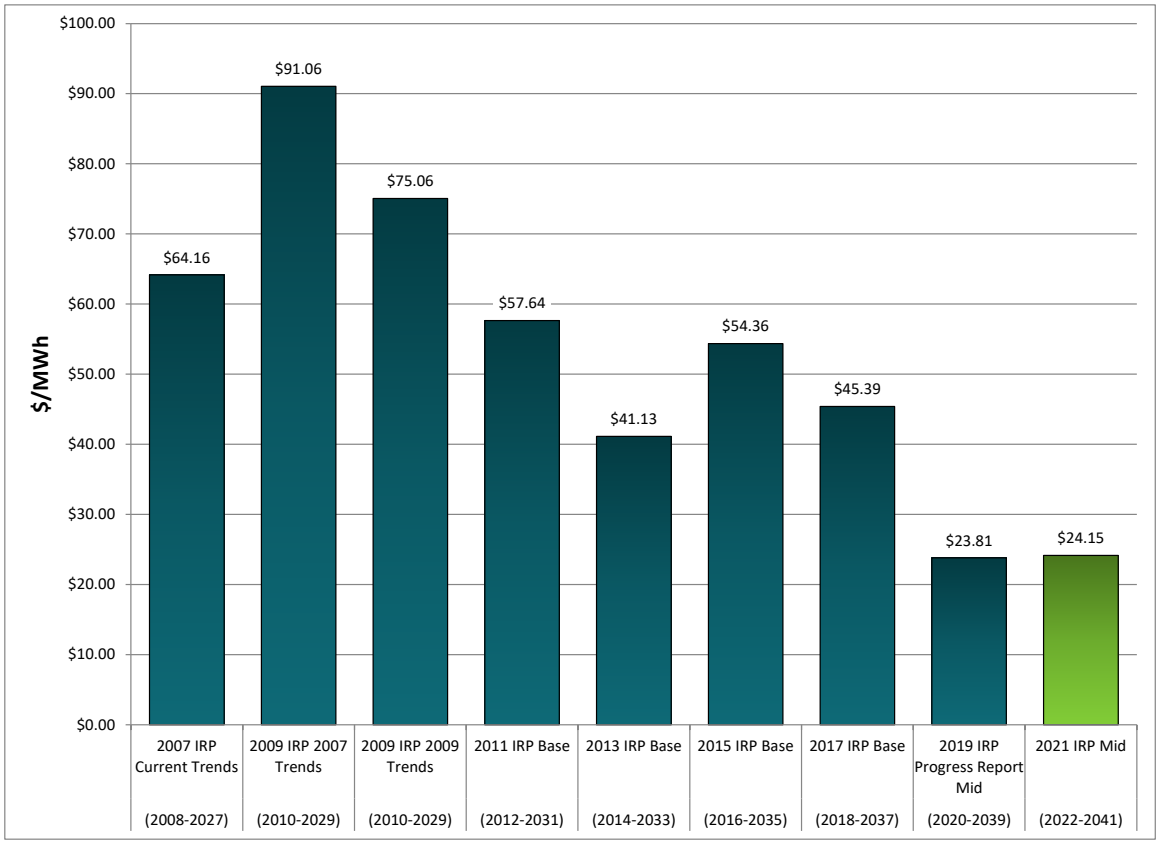


Figure 5-11 below compares the 2021 Mid Scenario power prices to past IRP power prices. In previous IRPs, the downward revisions in forecast power prices corresponded to the downward revisions in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations is driving much of the downward revision in forecasted power prices. The 2015 and 2017 IRP Base Scenarios included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions.

Figure 5-11: 2021 Levelized Power Prices Compared to Past IRPs ($/MWh)



Electric Portfolio Modeling Assumptions

For portfolio modeling, the following assumptions are applied to all scenarios.

Electric Resource Assumptions

PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

> > > *See Appendix D, Electric Resources and Alternatives,* *for detailed descriptions of the supply-side resources listed here.*
> > > *See Appendix E, Conservation Potential Assessment and Demand Response Assessment,* *for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They include three categories: retrofit programs that have shorter lives, such as efficient light bulbs; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.) Energy efficiency also includes some small-scale electric distributed generation such as combined heat and power.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.

DISTRIBUTION EFFICIENCY. Voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

Distributed energy resources included the following.

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer peak load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely.

DISTRIBUTED SOLAR GENERATION. Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels located close to the source of the customer's load. Distributed solar was modeled as a residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-12. Solar data was obtained from the National Solar Radiation Database[16] and processed with the NREL System Advisory Model.[17]

Figure 5-12: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington Residential - rooftop	residential-scale, fixed-tilt, rooftop	15.7
Western Washington Residential - ground	residential-scale, fixed-tilt, ground	16.0

BATTERY ENERGY STORAGE. Two battery storage technology systems were analyzed: lithium-ion and flow technology. These systems are modular and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour and 4-hour lithium-ion batteries, as well as, 4-hour and 6-hour flow battery systems.

NON-WIRES ALTERNATIVES. The role of distributed energy resources (DER) in meeting system needs is changing and the planning process is evolving to reflect that change. Non-wires alternatives are being considered when developing solutions to specific, long-term needs identified on the transmission and distribution systems. The resources under study have the benefit of being able to address system deficiencies while simultaneously supporting resource needs and can be deployed across both the transmission and distribution systems, providing some flexibility with how system deficiencies are addressed. The non-wires alternatives considered during the planning process include energy storage systems and solar generation.

16 / *https://nsrdb.nrel.gov/*
17 / *https://sam.nrel.gov/*

Supply-side resources included the following.

WIND. Wind was modeled in seven locations throughout the northwest United States including: eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming and offshore Washington. A summary of capacity factors for each wind resources are provided below in Figure 5-13. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL) Wind Toolkit Database[18] and processed using an in-house, heuristic wind production model.

Figure 5-13: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
Eastern Washington	36.7
Central Montana	39.8
Eastern Montana	44.3
Idaho	33.0
Eastern Wyoming	47.9
Western Wyoming	39.2
Offshore Washington	34.8

SOLAR. Solar was modeled as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for solar resources modeled is provided in Figure 5-14. Solar data was obtained from the National Solar Radiation Database[19] and processed with the NREL System Advisory Model.[20]

18 / https://www.nrel.gov/grid/wind-toolkit.html
19 / https://nsrdb.nrel.gov/
20 / https://sam.nrel.gov/

Figure 5-14: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Eastern Washington	utility-scale, single-axis tracker	24.2
Western Washington	utility-scale, single-axis tracker	16.0
Idaho	utility-scale, single-axis tracker	26.4
Eastern Wyoming	utility-scale, single-axis tracker	27.3
Western Wyoming	utility-scale, single-axis tracker	28.0

PUMPED HYDRO ENERGY STORAGE. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries at utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability. PSE analyzed an 8-hour pumped hydro resource.

HYBRID RESOURCES. In addition to stand-alone generation and energy storage resources PSE modeled hybrid resources which combine two or more resources together at the same location to take advantage of synergies between the resources. PSE model three types of hybrid resource including: eastern Washington solar + 2-hour Lithium-ion battery, eastern Washington wind + 2-hour Lithium-ion battery, and Montana wind + pumped hydro.

BASELOAD THERMAL PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTs). F-type, 1x1 engines with wet cooling towers are assumed to generate 348 MW plus 19 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS (SIMPLE-CYCLE COMBUSTION TURBINES OR SCCTs). F-type, wet-cooled turbines are assumed to generate 237 MW and to be located in PSE's service territory. These resources are modeled with either natural gas or an alternative fuel as the fuel source.

Baseload and peakers

*"**Baseload**" generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year.*

*"**Peaker**" is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.*

RECIP PEAKERS (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.2 MW each) is assumed to generate a total of 219 MW and to be located in PSE's service territory.

Electric Resource Cost Assumptions

Generic resource cost assumptions were generated through review of numerous data sources related to generating resources costs and collaboration with the IRP stakeholder group. The generic resource cost assumption methodology was inspired and informed by the NPCC Generating Resource Advisory Committee's (GRAC) cost assumption process.[21]

In brief, the methodology begins with accumulation of generic resource cost estimations from various organizations and regional IRP estimates. Since cost estimations were acquired from different sources, each cost estimate may include a different set of base assumptions, such as inclusion or exclusion of owner's or interconnection costs. Cost estimates were adjusted to align these assumptions as closely as possible. Cost estimates were then arranged by technology vintage year and summary statistics including average, median, minimum and maximum cost were calculated for each vintage year. All cost estimations and statistics were presented to the IRP stakeholder group with the recommendation that PSE use the average cost for modeling purposes. Stakeholder feedback, such as inclusion of new data sources and removal of specific data sources, was incorporated into final generic resource cost assumptions. The spreadsheet used for calculation of generic resource cost assumptions is

21 / *https://www.nwcouncil.org/energy/energy-advisory-committees/generating-resources-advisory-committee*

available for review on the PSE IRP website.[22] This spreadsheet includes a full list of the data sources used for cost estimate purposes and a breakdown of cost estimations by generic resource type.

> > > See Appendix D, Electric Resources and Alternatives*, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.*

Resource costs are generally expected to decline in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline (ATB).[23] The 2020 ATB was delayed due to the pandemic and was not available till after the generic resource costs for this IRP were finalized. The NREL ATB provides three cost curves for each resource, labeled as: Low, Mid and Constant Technology Cost Scenarios. PSE has selected the Mid Technology Cost Scenario for the IRP cost curves as it represents the "most-likely" future cost projection.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes engineering, procurement and construction, owner's costs, and interconnection costs. Interconnection costs include, as needed, natural gas pipelines and 5 miles of transmission from the substation to the main line. The costs calculated using the methodology described above resulted in "overnight capital costs" which typically exclude allowance for funds used during construction (AFUDC) and interconnection costs. PSE has assumed AFUDC costs at 10 percent of the overnight capital cost. PSE derived interconnection costs from a 2018 study on Generic Resource Costs for Integrated Resource Planning[24] prepared by consultant HDR for PSE. PSE believes the estimates used here are appropriate and reasonable.

- Figure 5-15 summarizes generic resource assumptions.
- Figure 5-16 summarizes annual capital cost by vintage year (the year the plant was built) for supply-side resources and energy storage.

22 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx
23 / https://atb.nrel.gov/electricity/2019/index.html?t=lw
24 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Figure 5-15: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First year available	Fixed O&M ($/kw-yr)	Variable O&M[1] ($/MWh)	Capital Costs, Vintage 2021 ($/kw)			
					Overnight Capital Cost	AFUDC[2]	Interconnection[3]	Total
CCCT	348	2025	12.87	3.32	1041	104	100	1246
Frame Peaker	237	2025	7.68	7.86	733	73	148	954
Recip Peaker	219	2025	6.40	7.05	1387	139	158	1683
WA Solar - Utility Scale	100	2024	22.23	0.00	1395	139	110	1644
Idaho/Wyoming Solar – Utility Scale	400	2026	22.23	0.00	1395	139	110	1644
WA Solar - Residential Scale	300	2024	0.00	0.00	3264	326	0	3590
Washington Wind	100	2024	40.60	0.00	1569	157	52	1778
Montana Wind	200	2024	40.60	0.00	1569	157	49	1774
Idaho/Wyoming Wind	400	2026	40.60	0.00	1569	157	49	1774
Offshore Wind	100	2030	110.08	0.00	4831	483	71	5385
Pumped Storage	25	2028	16.00	0.00	2367	237	52	2656
Battery 2hr Li-Ion	25	2023	23.49	0.00	937	94	63	1093
Battery 4hr Li-Ion	25	2023	31.93	0.00	1702	170	63	1934
Battery 4hr Flow	25	2023	21.76	0.00	2264	226	63	2553
Battery 6hr Flow	25	2023	37.97	0.00	3157	316	63	3535
Solar + battery	100 solar + 25 battery	2024	45.72	0.00	2099	210	155	2464
Wind + battery	100 wind + 25 battery	2024	64.09	0.00	2255	225	103	2584
Wind + pumped hydro	200 wind + 100 PHES	2028	56.60	0.00	3542	354	91	3988
Biomass	15	2024	207.00	6.20	5791	579	670	7040

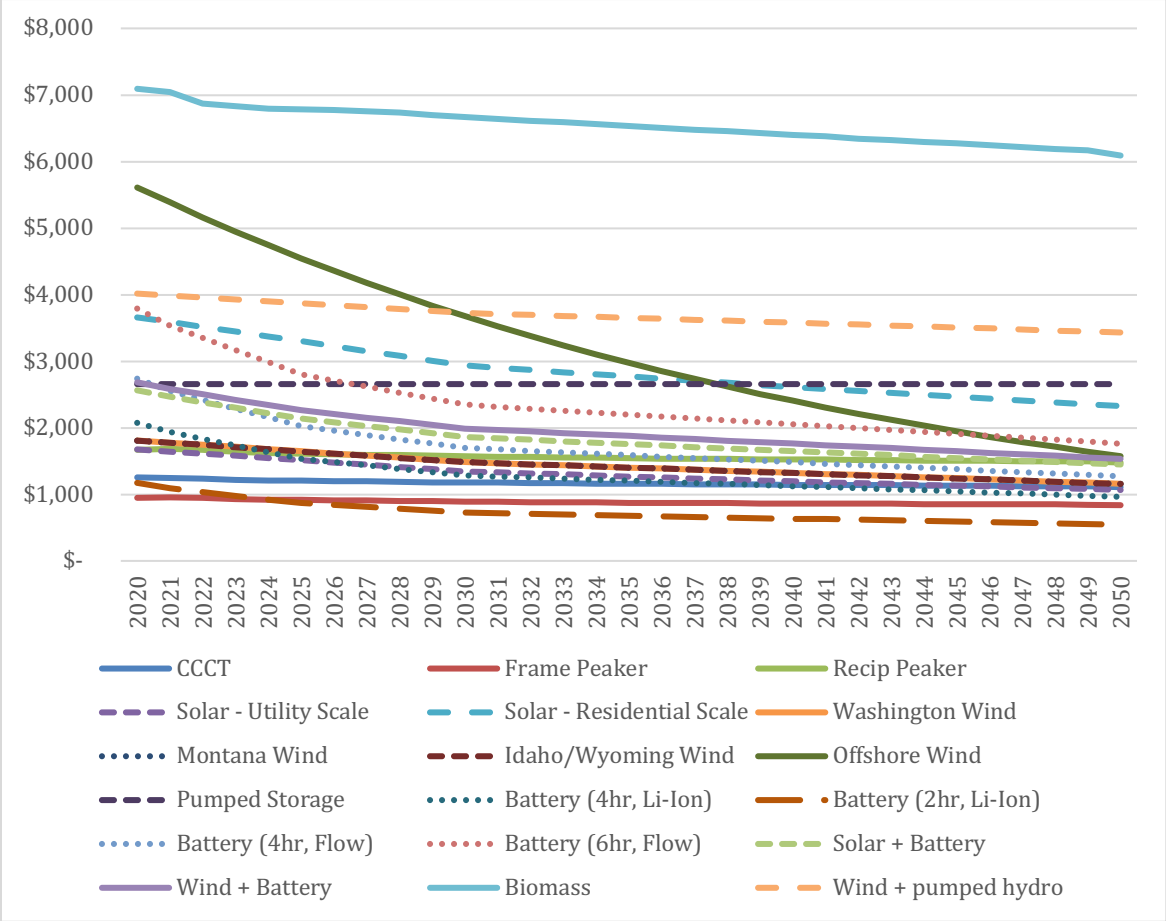
NOTES

1. *Variable O&M costs do not include the cost of fuel for thermal resources*
2. *AFUDC (Allowance for funds used during construction) is assumed at 10 percent of overnight capital*
3. *Interconnection costs includes the transmission, substation and natural gas pipeline infrastructure. Interconnection cost of offshore wind only includes onshore interconnection and does not include the cost of the marine cable to shore.*

The change in capital cost by vintage year is based on the NREL 2019 ATB Mid Technology Cost Scenario. These costs are decreasing on a real basis, but we add a 2.5 percent annual inflation rate for nominal costs. Figure 5-16 shows the annual capital cost of the resources modeled in this IRP by year built in 2020 real dollars.

> > > See Appendix D, Electric Resources and Alternatives, for cost curve charts broken out by resource type (renewable, energy storage and thermal).

Figure 5-16: Annual Capital Costs by Vintage Year (2020 real dollars)



Flexibility Considerations

This analysis focuses on the cost of balancing changes when different resources are added to PSE's portfolio.

The flexibility analysis focused on reflecting the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, different resources can impact costs and how the entire portfolio operates. For example, batteries could avoid dispatch of thermal plants for some ramping up and down.

For the sub-hourly flexibility analysis, PSE used a model called PLEXOS. First a Current Portfolio Case based on PSE's existing resources was created. The Current Portfolio Case begins by creating a simulation that reflects a complete picture of PSE as a BA and PSE's connection to the market. This includes representation of PSE's BAA load and generation on a day-ahead and real time, 15-minute basis. Opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the EIM market in 15-minute increments are also included. For this analysis, PSE simulated the year 2025 for both day-ahead and real time, and then took the difference in total portfolio cost between the two simulations.

PSE tested the impact of a range of potential new resources, each of which is individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the Current Portfolio Case cost, the cost reduction is identified as a benefit of adding the new resource.

Figure 5-17 below is the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.27/kw-yr. This cost savings is applied back to the fixed O&M of the generic resource as a reduction to the cost.

Figure 5-17: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kw-yr)
CCCT	$5.27
Frame Peaker	$23.45
Recip Peaker	$25.39
Lithium-ion battery 2hr	$20.45
Lithium-ion battery 4hr	$18.45
Flow battery 4hr	$23.03
Flow battery 6hr	$23.24
Pumped Storage Hydro 8hr	$18.41
Demand Response	$35.24

> > > See Appendix G, Electric Analysis Models, *for a detailed description of the methodology used to develop flexibility benefit.*

> > > See Appendix H, Electric Analysis Inputs and Results, *for further discussion of heat rate improvements, federal subsidies, financial assumptions such as discount rate and inflation, build constraints, and planned builds and retirements in the WECC.*

Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model which seek to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses and transmission costs.

- Transmission capacity constraints limit the quantity of generation development available to specific geographic regions.
- Transmission losses represent energy lost to heat as power is carried from location to another.
- Transmission costs model the cost of transmission to transmit power from a generating resource to PSE's service territory.

Transmission losses and costs have been a key component of the IRP portfolio model for many IRP cycles. Capacity constraints are a new addition to the modeling process for the 2021 IRP.

Transmission Capacity Constraints

Transmission capacity constraints have become an important modeling consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand, renewable resources are site-specific and have variable generation patterns dependent upon local wind or solar conditions, therefore they cannot track load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory because a wind farm in one location will produce a different amount of power from the same wind farm located in another location. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory.

ASSUMPTIONS. To model transmission capacity constraints, PSE created seven resource group regions and set limits on the generation capacity which may be built in each of those regions. Resource group regions were determined based on geographic relationships of the generic resources modeled in the 2021 IRP. Figure 5-18 summarizes the resource group regions and the generic resources available in each group.

Figure 5-18: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	Resource Group Region						
	PSE Territory (a)	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	Montana	Idaho / Wyoming
CCCT	X						
Frame Peaker	X						
Recip Peaker	X						
WA Solar East - Utility Scale		X	X		X		
WA Solar West - Utility Scale	X						
Idaho Solar – Utility Scale							X
WY Solar East – Utility Scale							X
WY Solar West – Utility Scale							X
DER WA Solar - Rooftop	X						
DER WA Solar – Ground	X						
WA Wind		X	X		X		
MT Wind – East						X	
MT Wind - Central						X	
ID Wind							X
WY Wind East							X
WY Wind West							X
Offshore Wind				X			
Pumped Storage		X	X		X		
Battery 2hr Li-Ion	X						
Battery 4hr Li-Ion	X						
Battery 4hr Flow	X						
Battery 6hr Flow	X						
Solar + battery		X			X		
Wind + battery		X			X		
Wind + pumped storage						X	
Biomass	X			X			

NOTE
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed

Capacity limits were developed based upon PSE's experience with available transmission capability (ATC) on BPA's system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies, regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building and acquisition are complex processes with a variety of possible outcomes, therefore a range of plausible transmission limits and timelines were developed for each region. To provide some structure to these ranges, PSE organized the transmission limits into tiers; uncertainty increases from tier to tier based on the ability of PSE to acquire that quantity of transmission. The tiers include:

- **Tier 1:** Transmission capacity that could likely be acquired in the 2022-2025 timeframe. This transmission capacity draws largely from repurposing PSE's existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that could be acquired in the 2025-2030 timeframe, but is less certain that than Tier 1 transmission projects. This transmission capacity adds new transmission resources to PSE's portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that could be acquired beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from the addition of long lead-time, new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 0:** Tier 0 represents a generally unconstrained transmission system, with the exception of very long distance resources. Tier 0 is used as the baseline transmission case for most of the modeling in the 2021 IRP as these assumptions most closely align with previous IRP cycles. Tiers 1, 2 and 3 are analyzed as sensitivities to gain an understanding of how transmission constraints could impact resource build decisions.

Figure 5-19 summarizes the transmission limits by tier for each resource group region.

Figure 5-19: Transmission Capacity Limitations by Resource Group Region

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

Rationale for each of the transmission capacity limitations by resource group region is provided below.

Eastern Washington: PSE may obtain 150, 300 or 640 MW, for Tiers 1, 2 and 3 respectively, of transmission to the Lower Snake River region through BPA Cluster Study requests. An additional 150, 375 or 690 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission may be acquired from developer submittals and resource retirements.

Central Washington: PSE may obtain 250, 500 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission by dual-purposing the existing 1,500 MW of Mid-C transmission currently used for market purchases. An additional 125 MW of transmission may be available in Tiers 2 and 3 for delivery of Kittitas area solar via Grant County PUD system.

Western Washington: Assumes no additional transmission available in Tier 1. Tier 2 may add 100 MW of BPA transmission following expiration of the TransAlta PPA in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may also add 200 MW of third-party transmission rights from developer submittals and resource retirements.



Southern Washington / Gorge: PSE may obtain 150, 375 or 685 MW, for Tiers 1, 2 and 3 respectively, of third-party transmission rights from developer submittals or resource retirements. Tier 2 may also add 330 MW of dual-purpose transmission to prioritize renewable generation from the Goldendale CCCT region.

Montana: PSE may obtain 350, 565 or 750 MW, for Tiers 1, 2 and 3 respectively, of transmission from repurposing transmission freed up by the removal of Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho: PSE may invest in new transmission projects including the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

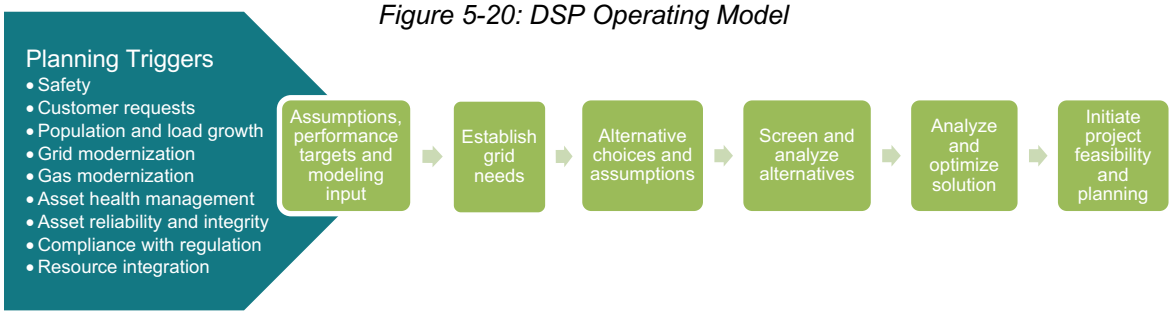
PSE Territory: The assumption for the 2021 IRP is that the PSE system in western Washington is unconstrained, this does not include PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades.

See Appendix M, Delivery System 10-year Plan, for detailed descriptions of transmission and distribution projects planned to ensure unconstrained delivery of resources.

Electric Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs, including effective integration of DERs. The approach and associated planning assumptions are shown in Figure 5-20 below.

Figure 5-20: DSP Operating Model



Assumptions	Description
Demand and Peak Demand Growth	Uses county demand forecast applied based on historic load patterns of substation circuits with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Aging Infrastructure	Known concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including NESC, NERC and WECC along with addressing voltage regulation, rapid voltage change, thermal limit violations and protection limits

DSP Non-wire Alternatives Forecast

A distributed energy resources forecast is included in the 2021 IRP that evaluates where DERs have been identified as a potential non-wires solution for meeting delivery system needs; the forecast is then extrapolated based on load growth assumptions. As needs arrive in the planning horizon, further analysis relative to specific values and potential will test these assumptions. The non-wires alternatives considered during the delivery system planning process include demand response, targeted energy efficiency, energy storage systems and solar generation, among others, and these resources are considered alone and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions tend to align with needs that are primarily driven by capacity or resiliency. As DER continues to be integrated into system solutions, key questions will need to be answered related to the operational flexibility afforded by DER, as well as related cyber-security considerations. The following assumptions were used to develop a DER forecast for solving identified system needs over the 0 to 10 year time frame.

- Due to practical sizing of DER solutions, projects with needs larger than 20MW were not considered.
- Average historical percentages were applied for determining energy efficiency, demand response and energy storage potential.
- 3 to 4 MW was determined to be a reasonable size for utility-scale PV based on industry knowledge and consultant input for summer needs.

For needs identified in the 10 to 20-year timeframe, the same assumptions were used but the values were extrapolated based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). Additional considerations were made to account for the planning process. Needs identified prior to 2023 are assumed to take 2 to 3 years to complete based on implementation of a new planning process and the learning curve associated with implementing new technologies. As the planning process matures and more experience is gained in siting DER, needs identified after 2023 are assumed to be built by the year that the need first materializes on the system.

Figure 5-21: Forecasted DER Installation by Year and Type

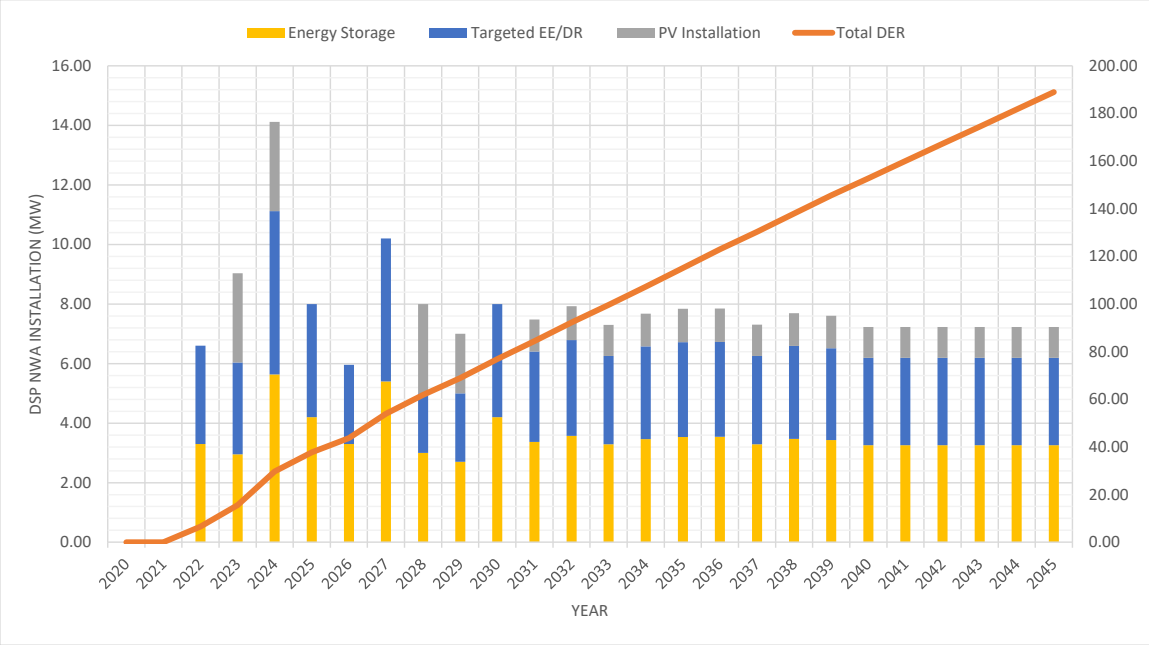


Figure 5-22: Projected T&D Deferral by Project Type by 2040

	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects*	6.6	6.0	0.0	12.6
Planned Substation Capacity Projects	18.1	17.2	6.0	41.3
Future Potential System Needs	60.4	53.7	21.0	135.1
Total	**85.1**	**76.9**	**27.0**	**189.0**

** As identified in the PSE Plan for Attachment K*

Only the energy storage and solar PV forecast was modeled in the IRP as part of the DSP non-wires alternatives. The targeted energy efficiency/demand response forecast is included as part of the cost-effective energy efficiency and demand response evaluation in the IRP.

Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material and voltage impact the magnitude of transmission line losses. BPA assumes a flat 1.9 percent line loss across its entire transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, PSE has assumed a similar loss given the similar distance. Figure 5-23 provides a summary of the transmission lines losses assumed by resource group region.

Figure 5-23: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
Montana	4.6
Idaho / Wyoming	4.6

Transmission Cost Constraints

Transmission cost is another factor used in the PSE Portfolio Model to constrain resource build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-yr) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to PSE's service territory. Variable transmission costs are largely composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Figure 5-24 provides a summary of fixed and variable transmission costs by generic resource type.

Figure 5-24: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-yr)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East - Utility Scale	30.48	9.53
WA Solar West - Utility Scale	8.28	9.53
Idaho Solar – Utility Scale	154.78	9.53
WY Solar East – Utility Scale	227.90	9.53
WY Solar West – Utility Scale	207.80	9.53
DER WA Solar - Rooftop	0.00[a]	0.00
DER WA Solar – Ground-mount	0.00[a]	0.00
WA Wind	33.36	9.53
MT Wind – East	49.65	9.53
MT Wind - Central	49.65	9.53
ID Wind	157.66	9.53
WY Wind East	230.78	9.53
WY Wind West	210.68	9.53
Offshore Wind	33.36	9.53
Pumped Storage	22.20	0.00
Battery 2hr Li-Ion	0.00[a]	0.00
Battery 4hr Li-Ion	0.00[a]	0.00
Battery 4hr Flow	0.00[a]	0.00
Battery 6hr Flow	0.00[a]	0.00
Solar + Battery	30.48	9.53
Wind + Battery	33.36	9.53
Wind + Pumped Storage	49.65	9.53
Biomass	22.20	0.00

NOTE
a. Fixed transmission cost is not applied, because the resource is assumed to be built within PSE service territory.

Electric Generation Retirements

For the 2021 IRP, PSE is modeling the economic retirement of existing thermal resources. Colstrip is assumed to be removed from PSE's portfolio by December 31, 2025, but the model is allowed to retire Colstrip earlier based on economics. The other thermal plants are assumed to run through the planning horizon, but they are also allowed to retire early based on economics.

When determining retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The valuation process for the generating plants considers the cost of emissions, variable costs (including fuel and operations and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

Electric Portfolio Sensitivities

Starting with the optimized, least cost Mid Scenario portfolio, sensitivities change a resource, environmental regulation or condition in order to examine the effect of that change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. During the 2021 IRP process, the Resource Planning team identified over 50 potential modeling sensitivities. As part of the 2021 IRP public participation process, the planning team asked stakeholders for assistance in prioritizing which sensitivity analyses to perform. Appendix A, Public Participation, describes the sensitivity prioritization process. Figure 5-25 summarizes the sensitivities modeled in this IRP.

Figure 5-25: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp in over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Sensitivities	**Alternatives Analyzed**
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon free combustion turbines using biodiesel as the fuel.
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus a reduced access to the Mid-C market for sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources (energy efficiency, distribution efficiency and demand response).
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

A. Renewable Overgeneration Test

In the portfolio model, excess renewable energy that is produced and sold to the Mid-C market is counted towards PSE's CETA renewable goals. In practice, because this energy would not serve PSE loads, it would not count toward meeting CETA goals. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales with respect to renewable overgeneration.

BASELINE ASSUMPTION: PSE can sell excess renewable production to the Mid-C Market.
SENSITIVITY > PSE is not able to sell excess renewable production to the Mid-C Market.

B. Reduced Firm Market Access at Peak Hours

PSE currently uses market purchases of energy in order to meet demand at peak demand hours. As regional emitting resources are retired in response to decarbonization policies and the regional generation supply mix transforms, Mid-C market purchases may not be available to meet peak capacity. This sensitivity reduces the amount of market purchases and sales that can be made, allowing PSE to examine an optimized portfolio that does not rely heavily on market. Determining the behavior of the model under different market circumstances can inform PSE how to navigate a market with reduced peak availability.

BASELINE ASSUMPTION: PSE can purchase and sell up to the Mid-C transmission limit, typically 1500 MW.
SENSITIVITY > The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November, and December) and the summer months (June, July, and August) are also reduced by 200 MW per year down to 500 MW by 2027.

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE's system experiences transmission constraints, and the projects available to increase transmission include Tier 1 and Tier 2 transmission projects.

D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines a transmission constraint on the PSE system that is relaxed over time. Transmission will be limited to Tier 1 constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035. PSE's transmission connection to the Mid-C market remains unchanged in this sensitivity from the Mid Scenario.

BASELINE ASSUMPTION: PSE's system only has transmission constraints between the PSE system and the Mid-C market.
SENSITIVITY > PSE experiences Tier 1 transmission constraints until 2025, Tier 2 constraints until 2030, Tier 3 constraints until 2035, and unconstrained after 2035.

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity explores the acquisition of firm transmission for new resources being less than the total nameplate capacity of the resource. For renewable resources, this may provide a monetary benefit for building less transmission for resources that do not always reach maximum output.

BASELINE ASSUMPTION: New resources are acquired with transmission capable of carrying the full output of the resource.
SENSITIVITY > New resources are obtained with firm transmission that is less than their nameplate capacity.

F. 6-Year Conservation Ramp Rate

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

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

G. Non-energy Impacts

This sensitivity adds additional non-energy impacts to the adoption of measures. This increases the amount of energy savings from conservation, assuming there are additional benefits and changes not captured in the data.

BASELINE ASSUMPTION: Conservation measures have the expected load reduction.
SENSITIVITY > Additional conservation measures are cost effective as non-energy impacts reduces the cost of more expensive conservation measures.

H. Social Discount Rate for DSR

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

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

I. SCGHG as an "Externality Cost" (Dispatch Cost) in the Portfolio Model

This sensitivity includes the SCGHG as an externality cost expressed as a variable dispatch cost in the long-term capacity expansion (LTCE) model (only) instead of as a fixed planning adder in order to compare the dispatch methodology to the planning adder methodology. This sensitivity uses the mid electric price forecast with the SCGHG as a separate planning adder to market purchases in the LTCE.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE Model.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model.

J. SCGHG as A Dispatch Cost in Electric Prices and Portfolio Model

This sensitivity includes the SCGHG as a dispatch cost in the LTCE modeling process and in the hourly dispatch and electric price forecast, to compare the dispatch cost methodology with the planning adder methodology. This sensitivity uses a different electric price forecast than in the Mid Scenario portfolio. The SCGHG is added to the electric model as a dispatch cost (tax), so it's included in the electric price forecast. This differs from Sensitivity I in that the electric price with SCGHG is then used in the LTCE instead of the mid electric price plus a planning adder.

BASELINE ASSUMPTION: The SCGHG is included as a fixed cost of resources in the LTCE model only.
SENSITIVITY > The SCGHG is included as a variable cost of resources in the LTCE model and the hourly dispatch model.

K. AR5 Upstream Emissions

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

BASELINE ASSUMPTION: PSE will use the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu (23 lbs/MMBtu) to the emission rate of natural gas plants.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu (25 lbs/MMBtu) to the emission rate of natural gas plants.

L. SCGHG as a Fixed Cost Plus a Federal CO_2 Cost

This sensitivity includes a Federal CO_2 tax modeled as $15 per short ton with inflation to provide insight into portfolio impacts in the event of a Federal CO_2 tax.

BASELINE ASSUMPTION: The SCGHG is modeled as a planning adder in the LTCE model only.
SENSITIVITY > The SCGHG is modeled as a planning adder in the LTCE model, as well as a $15 per short ton CO_2 tax that is indexed to inflation.

M. Alternative Fuel for Peakers

This sensitivity will model biodiesel as an available fuel option for peaker plants. Results will provide insight into the costs associated with converting the plants to an alternative fuel to meet CETA requirements. Although PSE intended to model hydrogen as an alternative fuel source, PSE did not have sufficient hydrogen pricing at the time of this IRP to perform the analysis.

BASELINE ASSUMPTION: Peaker plants use natural gas as fuel.
SENSITIVITY > Peaker plants use biodiesel as an alternative fuel.

N. 100% Renewable by 2030

This sensitivity forces PSE to adopt 100% renewable resources by 2030, eliminating all natural gas generation to provide context and insight for the push to 100 percent renewable resources by 2045.

BASELINE ASSUMPTION: PSE must reach 100% renewable resources by 2045.
SENSITIVITY > PSE must reach 100% renewable resources by 2030, and all natural gas generation is retired in 2030.

O. 100% Renewable by 2045

This sensitivity forces all natural gas generating plants to be retired by 2045, instead of waiting for economic retirements with CETA penalties. The results will allow PSE to compare the current plans for natural gas plant retirement with CETA penalties.

BASELINE ASSUMPTION: Carbon-emitting resources retire at the end of their economic life.
SENSITIVITY > In 2045, all carbon-emitting resources are retired, regardless of their economic viability.

P. No New Thermal Resources before 2030

This sensitivity does not allow thermal resources to be built before 2030 to allow the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need. Results from this sensitivity will provide insight into how energy storage provides value to the system that has traditionally been provided by natural gas plants.

BASELINE ASSUMPTION: Resources are acquired when they provide the most value to the portfolio.
SENSITIVITY 1 > No new thermal resources are added in the near-term capacity need. The model optimizes to the next lowest cost resource.
SENSITIVITY 2 > Instead of battery storage as the optimal resource, the model uses pumped hydro storage as the resource to meet capacity needs.
SENSITIVITY 3 > The model uses 4-hour lithium-ion battery storage as the resource to meet capacity needs.

Q. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory.

R. Temperature Sensitivity

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

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

S. SCGHG Included, No CETA

This sensitivity will model the SCGHG as a fixed cost adder, but not include the CETA renewable requirement. Results from this sensitivity will help to quantify the effect of the SCGHG as a fixed cost adder on the portfolio. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > The SCGHG is included in the modeling process as it is in the Mid Scenario, but all other CETA renewable requirements are removed. The portfolio will meet the RCW 19.285 15 percent renewable target.

T. No CETA

This sensitivity will model the portfolio with no SCGHG as a fixed cost adder and no CETA renewable requirement. Results from this sensitivity will help to quantify the effect of CETA. Results will also allow PSE to quantify a baseline of costs without the CETA legislative constraints.

BASELINE ASSUMPTION: All CETA requirements, including the SCGHG, are included as modeling constraints.
SENSITIVITY > SCGHG and CETA renewable targets removed. Portfolio will meet RCW 19.285 15% renewable target.

U. 2% Cost Threshold

CETA is considered fulfilled once renewable targets are met or once the investments imposed by CETA constraints reach 2 percent of the annual revenue requirement. This sensitivity is included for information only. The Clean Energy Implementation Plan will reconcile competing CETA requirements.

BASELINE ASSUMPTION: The portfolio model must meet CETA renewable energy targets.
SENSITIVITY > CETA requirements are considered met once the portfolio costs reach 2 percent of the annual revenue requirement.

V. Balanced Portfolio

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources. The inputs for the balanced portfolio were developed using insights gained from analyzing the results of other sensitivity analyses and through the Customer Benefit Indicator framework. The regular electric capacity expansion model is set to optimize total portfolio cost, which delays new builds until near the end of the planning period. This delay produces a lower portfolio cost since the cost curve for all the resources declines over time; however, in reality, it is not always possible to wait until the end years to add a lot of resources. In Sensitivity C, Transmission Build Constraints, the model waits until the last 5 to 10 years to add a significant amount of distributed resources. The balanced portfolio takes those distributed resources and ramps them in over time starting in 2025 and adds more customer programs to meet CETA requirements.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030

W. Balanced Portfolio with Alternative Fuel for Peakers

This sensitivity will be performed in order to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus uses biodiesel as a fuel source for new peaking capacity. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time, plus alternative fuel for combustion turbines as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year from the year 2025 to 2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- Biodisel used as fuel source for peaking combustion turbines

X. Balanced Portfolio with Reduced Firm Market Access at Peak

This sensitivity is performed to compare the Mid Scenario portfolio with a portfolio that gives increased consideration to distributed energy resources plus decreases market reliance to 500 MW by 2027. The inputs for this portfolio were also developed using insights gained from the results of other sensitivity analyses.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year 2025-2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030
- The available market at peak is reduced by 200 MW per year down to 500 MW by 2027. The available purchases during the winter months (January, February, November and December) and the summer months (June, July, and Augus)t are also reduced by 200 MW per year down to 500 MW by 2027.

WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivity WX applies the three key changes in Sensitivities V, W and X simultaneously.

Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity WX > Additional DER and customer programs are added to the portfolio as in Sensitivity V; biodiesel is used as a fuel for newly built frame peaker resources as in Sensitivity W; and the portfolio has reduced access to market purchases during peak demand months as in Sensitivity X.

Y. Maximum Customer Benefit

RCW 19.405.040(8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.
SENSITIVITY > Create a portfolio around maximizing different customer benefit indicators.

Z. No DSR

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

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > No new energy efficiency and demand response is allowed in the portfolio and all future needs will be met by supply-side resources.

AA. Montana Wind Plus Pumped Hydro Storage

This portfolio evaluates the hybrid resource of wind plus pumped storage hydro.

BASELINE ASSUMPTION: New resources are acquired when cost effective and needed, conservation and demand response measures are acquired when cost-effective.
SENSITIVITY > Instead of adding only Montana wind to the portfolio, the hybrid resource of Montana wind plus pumped hydro storage is added.

3. NATURAL GAS ANALYSIS

Natural Gas Scenarios

Three scenarios were created for the natural gas portfolio analysis to test how different combinations of two fundamental economic conditions – customer demand and natural gas prices – impact the least-cost mix of resources.

Figure 5-26: 2021 IRP Natural Gas Analysis Scenarios

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

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

Scenario 1: Mid

The Mid Scenario is a set of assumptions that is used as a reference point against which other sets of assumptions can be compared.

DEMAND

- The 2021 IRP Base (Mid) Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Mid natural gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 2: Low

This scenario models weaker long-term economic growth than the Mid Scenario. Customer demand is lower in PSE's service territory.

DEMAND

- The 2021 IRP Low Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Scenario 3: High

This scenario models more robust long-term economic growth, which produces higher customer demand.

DEMAND

- The 2021 IRP High Demand Forecast is applied for PSE.

NATURAL GAS PRICES

- Natural gas prices are higher as a result of increased demand; the Wood Mackenzie long-term high forecast is applied to natural gas prices.

CO_2 PRICE

- The social cost of greenhouse gases is reflected as a price adder to the natural gas price.
- The costs of upstream CO_2 emissions are reflected as a price adder to the natural gas price.

Natural Gas Scenario Inputs

PSE Customer Demand

The graphs below show the peak demand and annual energy demand forecasts for natural gas service without including the effects of demand side resources (DSR). The forecasts include sales (delivered load) plus system losses. The natural gas peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

Figure 5-27: 2021 IRP Natural Gas Sales Peak Day Demand Forecast – Low, Mid, High

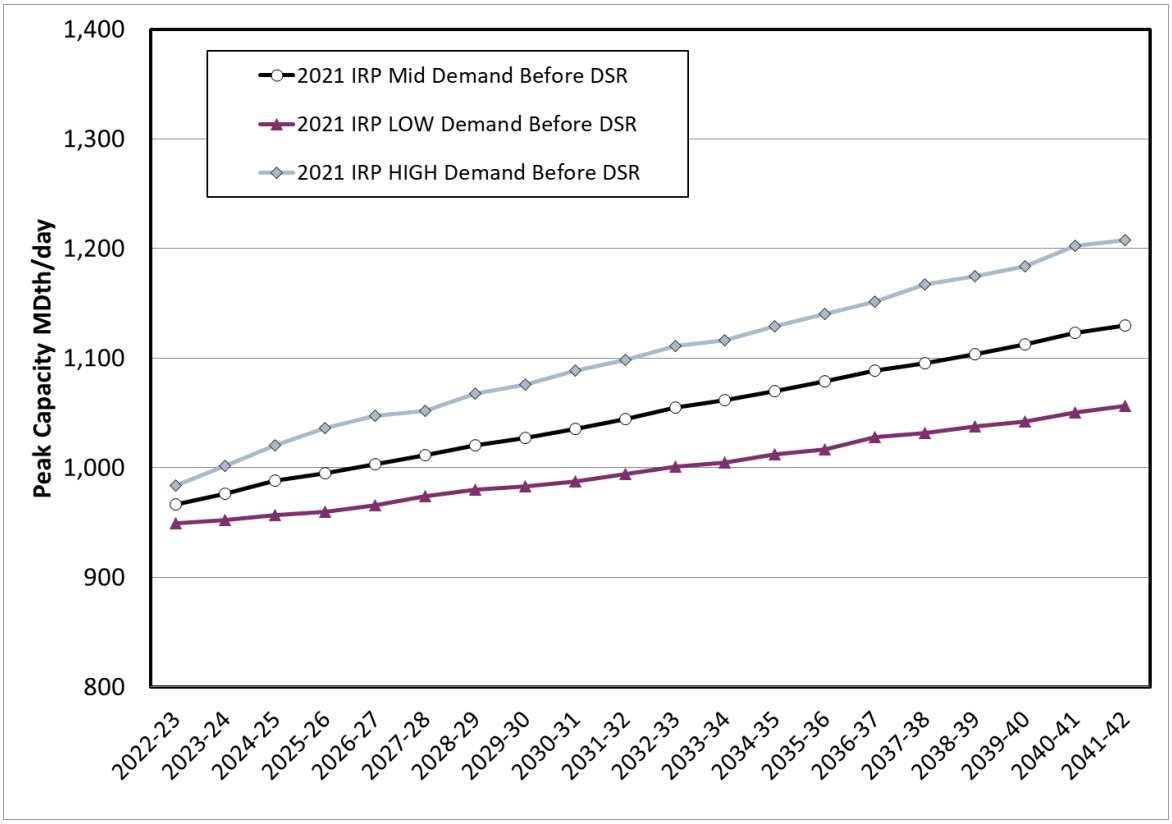
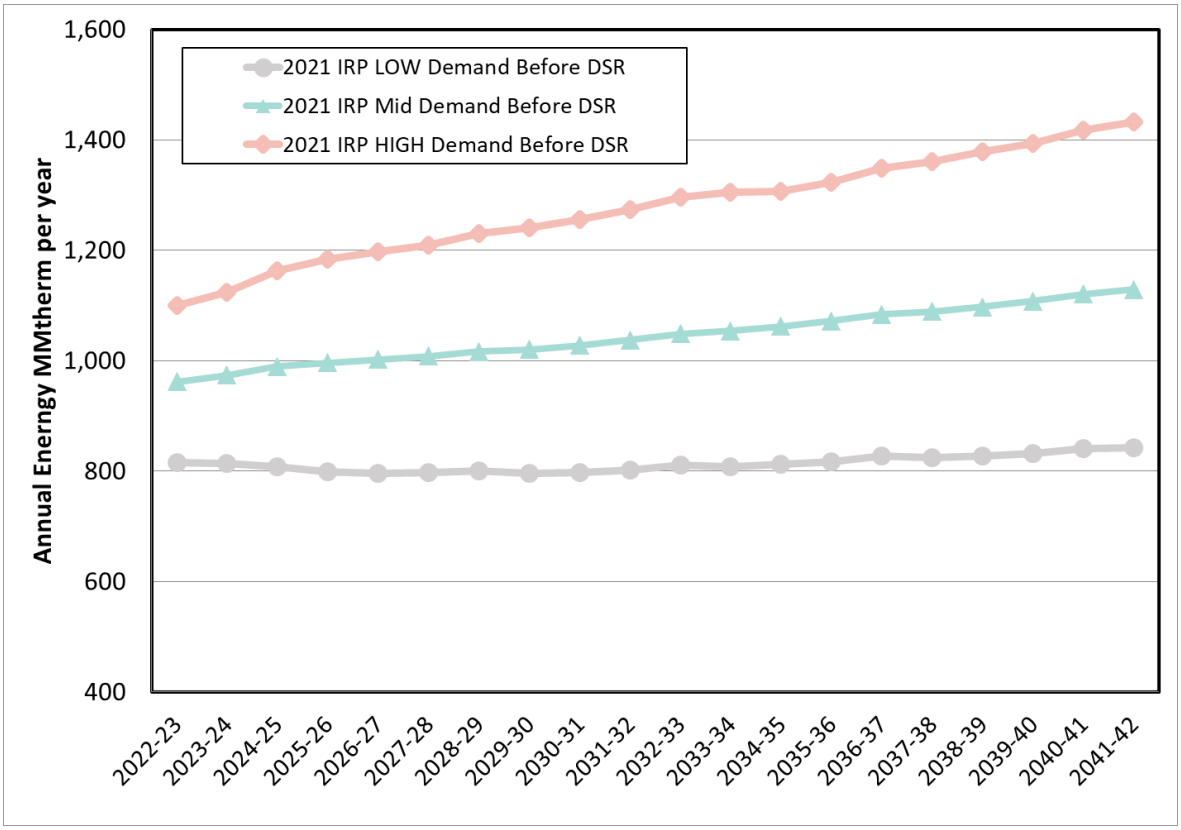


Figure 5-28: 2021 IRP Annual Natural Gas Sales Demand Forecast – Low, Base (Mid), High



Natural Gas Price Inputs

For natural gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in Spring 2020[25] from Wood Mackenzie.[26]

- From 2022-2026, this IRP uses the three-month average of forward market prices from June 30, 2020. Forward market prices reflect the price of natural gas being purchased at a given point in time for future delivery.
- Beyond 2029, this IRP uses the Wood Mackenzie long-run natural gas price forecast published in July 2020.

25 / The Spring 2020 forecast from Wood Mackenzie is updated to account for economic and demographic changes stemming from the COVID-19 pandemic.

26 / Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas exports.



For the years 2027 and 2028, a combination of forward market prices from 2026 and selected Wood Mackenzie prices from 2029 are used to minimize abrupt shifts when transitioning from one dataset to another.

- In 2027, the monthly price is the sum of two-thirds of the forward market price for that month in 2026 plus one-third of the 2029 Wood Mackenzie price forecast for that month.
- In 2028, the monthly price is the sum of one-third of the forward market price for that month in 2026 plus two-thirds of the 2029 Wood Mackenzie price forecast for that month.

Three natural gas price forecasts are used in the scenario analyses.

MID NATURAL GAS PRICES. The mid natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020.

LOW NATURAL GAS PRICES. The low natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie low price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

HIGH NATURAL GAS PRICES. The high natural gas price forecast uses the three-month average of forward market prices from June 30, 2020 and an adjusted Wood Mackenzie fundamentals-based long-run natural gas price forecast published in July 2020. To adjust the Wood Mackenzie forecast, PSE used the data trends from the Spring 2018 Wood Mackenzie high price forecast and applied them to the most recent fundamentals forecast. The underlying factors that influence the high and low reports have not changed significantly between the Spring 2018 and Spring 2020 forecasts.

Figure 5-29 below illustrates the range of 20-year levelized natural gas prices used in the 2021 IRP analysis, along with the carbon adders used to develop the total natural gas cost.

Figure 5-29: Levelized Natural Gas Prices and Carbon Adders Used in Scenarios, 2021 IRP

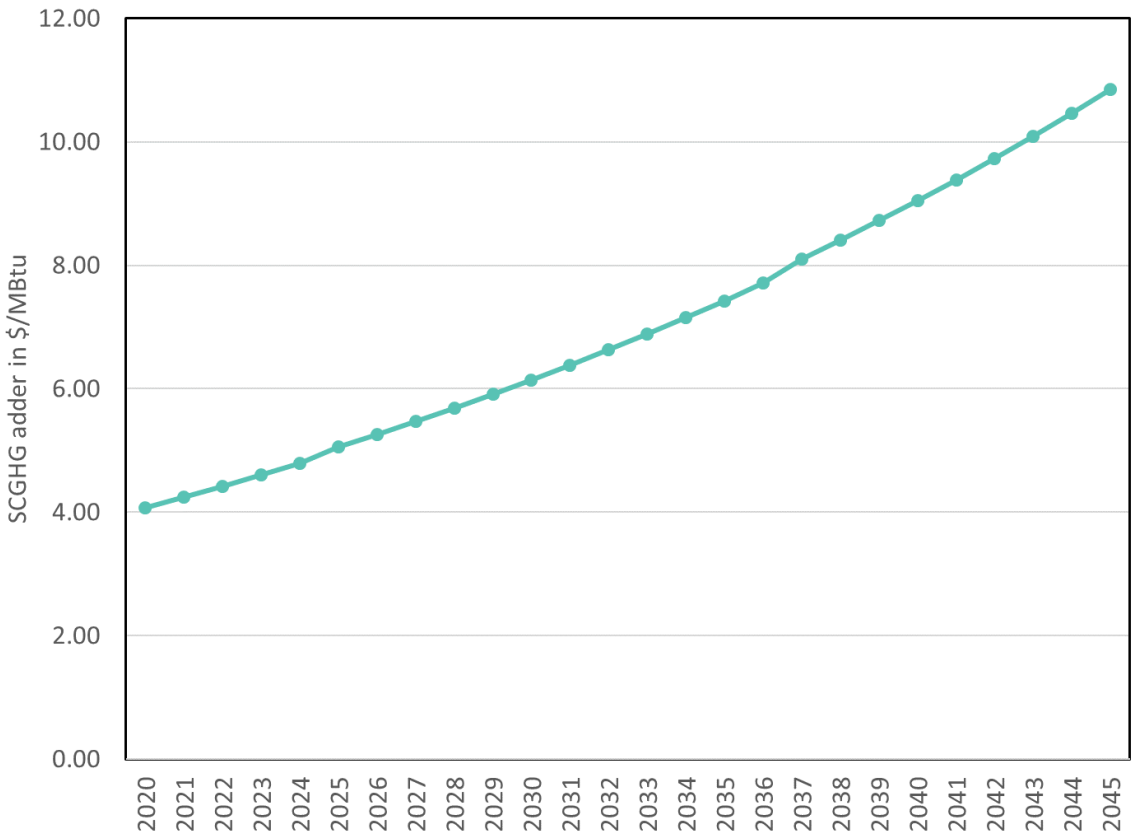


CO_2 Price Inputs

RCW 80.28.380 requires that the natural gas analysis include the cost of greenhouse gases when evaluating the cost-effectiveness of natural gas conservation targets. To implement this requirement, the SCGHG is added to the natural gas commodity price.

SOCIAL COST OF GREENHOUSE GASES. Per RCW 80.28.395, the social cost of greenhouse gases is based on the cost from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the CO_2 prices in real dollars and metric tons. PSE has adjusted the prices for inflation (nominal dollars) and converted to U.S. tons (short tons). This cost ranges from **$69 per ton in 2020 to $238 per ton in 2052.** This was then converted to a dollars per MMBtu value resulting in Figure 5-31.

Figure 5-30: Social Cost of Greenhouse Gases Used in the 2021 IRP ($/MMBtu)



UPSTREAM CO_2 EMISSIONS FOR NATURAL GAS. The upstream emission rate represents the carbon dioxide, methane and nitrous oxide releases associated with the extraction, processing and transport of natural gas along the supply chain. These gases were converted to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[27]

27 / Both the EPA and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, PSE used emission rates published by the Puget Sound Clean Air Agency[28] (PSCAA). PSCAA used two models to determine these rates, GHGenius[29] and GREET.[30] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin.

Figure 5-31: Upstream Natural Gas Emissions Rates

	Upstream Segment	End-use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMbtu	= 65,203 g/MMBtu	19.9%
GREET	12,121 g/MMBtu	+ 54,400 g/MMbtu	= 66,521 g/MMBtu	22.3%

NOTE: End-use Combustion Emission Factor: EPA Subpart NN

Delivery of Natural Gas within the PSE System

The assumption for the 2021 IRP is that the PSE natural gas delivery system in western Washington is unconstrained. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan that includes transmission and distribution system upgrades. See Appendix M, Delivery System 10-year Plan, for more detailed descriptions of each project.

28 / Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019
29 / GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca/
30 / GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.

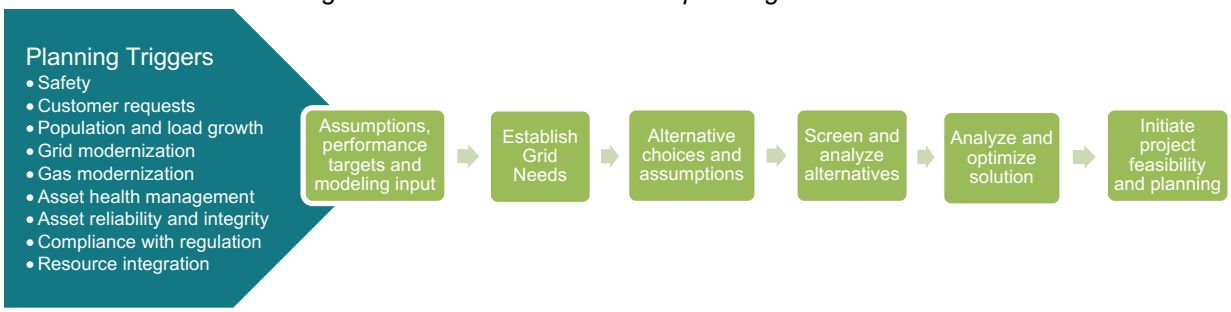
Figure 5-32: Natural Gas Distribution System Planned Work

Transmission and Distribution Summary – Planned work to ensure delivery of resources unconstrained	Description (to be completed for the final IRP)	Project Phase & Estimated In-service date	Potential DER Location
New Intermediate Pressure Main	36 miles	Ongoing	
Gate or Limit Station Upgrades	5	Ongoing	
District Regulation	26	Ongoing	
Gas Main Replaced	200-300 miles	Ongoing	
Bonney Lake Reinforcement (Phase 1)	The project has provided additional capacity and reliability to serve the growth in Bonney Lake area. Phase 1 of the project involved constructing 1.7 miles of 16-inch high pressure main.	36 miles	
Bonney Lake Reinforcement (Phase 2, 3 and 4)	Project driver is to ensure reliability and adequate capacity	5	X
North Lacey Reinforcement	Project driver is to ensure reliability and adequate capacity	26	
Sno-King Reinforcement Projects	Project driver is to ensure reliability and adequate capacity	200-300 miles	
Tolt Pipeline	Project driver is to ensure reliability and adequate capacity	Initiation needed by 2023	

Natural Gas Delivery System Planning Assumptions

PSE follows a structured approach to developing infrastructure plans that support various customer needs including effective integration of DERs.

Figure 5-33: DSP Natural Gas Operating Model



Assumptions	Description
Peak Hour Demand Growth	Uses county demand forecast applied based on historic load patterns of zip codes with known point loads adjusted for
Energy Efficiency	Highly optimistic 75% and 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Known interconnection requests included
Pipeline Safety and Aging Infrastructure	Known risk-based concerns included in analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources / Manual intervention	Known controllable devices are included where possible such as compressed natural gas injection at low pressure areas or bypassing valves
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements including Federal PHMSA and pipeline safety WAC codes, such as addressing low pressure concerns or over-pressure events

Natural Gas Alternatives Modeled

Energy efficiency, transportation and storage are key resources for natural gas utilities. PSE modeled the following generic resources as potential portfolio additions in this IRP analysis.

> > > *See* ***Chapter 9, Gas Analysis****, for detailed descriptions of the resources listed here.*
> > > *See* ***Appendix E, Conservation Potential Assessment and Demand Response Assessment****, for detailed information on demand-side resource potentials.*

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. These are a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. They include three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. (Codes and standards impact the demand forecast but have no direct cost to utilities.)

Supply-side resources included the following.

Transport pipelines that bring natural gas from production areas or market hubs to PSE's service area generally require assembling a number of specific segments and/or natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Seven alternatives were analyzed in this IRP.

Combination # 1 & 1a – NWP Additions + Westcoast

After November 2025, this option expands access to northern British Columbia natural gas at the Station 2 hub, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded Northwest Pipeline (NWP) to PSE's service area. Natural gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be prudent and necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity from Sumas.

COMBINATION #1A – SUMAS DELIVERED NATURAL GAS SUPPLY. This short-term delivered supply alternative utilizes capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2019 to October 2024 in the form of annual winter contracts. This alternative is intended to provide a short-term bridge to long-term resources. Pricing would reflect Sumas daily pricing and a full recovery of pipeline charges. PSE believes that the vast majority – if not all – of the under-utilized firm pipeline capacity in the I-5 corridor that could be used to provide a delivered supply has been or will be absorbed by other new loads by Fall 2025. After that, other long-term resources would need to be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

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

Combination # 3 – Cross Cascades – NWP from AECO

This option provides for deliveries to PSE via a prospective upgrade of NWP's system from Stanfield, Oregon to contracted points on NWP in the I-5 corridor. Availability is estimated no earlier than November 2025. The increased natural gas supply would come from Alberta (AECO hub) via new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield, Oregon. Final delivery from Stanfield to PSE would be via the upgraded NWP facilities across the Columbia gorge and then northbound to PSE gate stations. Since the majority of this expansion route uses existing pipeline right-of-way, permitting this project would likely be less complicated than for a greenfield project such as the option presented in Combination #2. Also, since smaller increments of capacity are economically feasible with this alternative, PSE is more likely to be able to dictate the timing of the project.

Combination # 4 – Mist Storage and Redelivery

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

Combination # 5 – Plymouth LNG with Firm Delivery

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

Combination # 6 – LNG-related Distribution Upgrade

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

Combination # 7 – Swarr LP-Air Upgrade

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

Natural Gas Resource Build Constraints

Natural gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent "lumpiness" in natural gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2025 – 2028 and 2033 – 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility's upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Natural Gas Portfolio Sensitivities

Figure 5-34: 2021 IRP Natural Gas Portfolio Sensitivities

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

A. AR5 Upstream Emissions

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

BASELINE ASSUMPTION: PSE uses the AR4 Upstream Emissions calculation methodology which adds 10,803 g/MMBtu to Canadian supply emissions and 12,121 g/MMBtu to US supply emissions.
SENSITIVITY > PSE will use the AR5 Upstream Emissions calculation methodology which adds 11,564 g/MMBtu to Canadian supply emissions and 13,180 g/MMBtu to US supply emissions.

B. 6-Year Conservation Ramp Rate

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

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

C. Social Discount Rate for DSR

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

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

D. Fuel Switching, Gas to Electric

This sensitivity models an increased adoption of gas-to-electric conversion within the PSE service territory. Results from this sensitivity will illustrate the effects of rapid electrification on the portfolio and the demand profile of the PSE service territory.

BASELINE ASSUMPTION: The portfolio uses the standard demand forecast for the Mid Scenario.
SENSITIVITY > The demand forecast is adjusted to include an increased electrification rate of natural gas customers in the PSE service territory resulting in a lower natural gas demand forecast.

E. Temperature Sensitivity

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

BASELINE ASSUMPTION: PSE uses the base demand forecast.

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

F. No DSR

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

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

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



2021 PSE Integrated Resource Plan

6 Demand Forecasts

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts and peak demand over a 20-year period. These forecasts are designed for use in long-term resource planning and in Delivery System Planning (DSP) needs assessments.

6 Demand Forecasts

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1. OVERVIEW

The demand forecasts developed for the IRP estimate the amount of electricity or natural gas that will be required to meet the needs of customers over the 20+ year study period. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand refers to the total amount of electricity or natural gas needed to meet customer needs in a given year.
- Peak demand refers to the amount of electricity or natural gas needed to serve customer need on the coldest day of the year, since PSE is a winter-peaking utility.

NOTE: The terms “demand” and “load” are often used interchangeably, but they actually refer to different concepts. “Demand” refers to the amount of energy needed to meet the needs of customers during a calendar year, including losses. “Load” refers to demand plus the planning margin and operating reserves needed to ensure reliable and safe operation of the electric and natural gas systems.

Overall, electric energy demand before additional conservation in the 2021 IRP Base Demand Forecast is expected to grow at an average annual rate of 1.2 percent during the study period from 2022 to 2045, resulting in an increase from 2,500 aMW in 2022 to 3,316 aMW in 2045. This is slower than the 1.4 average annual energy growth rate forecast during the 2019 IRP Process. Electric peak demand before additional conservation is expected to increase at a 1.2 percent annual growth rate, resulting in an increase from 4,687 MW in 2022 to 6,159 MW in 2045. This is also slower than the 1.3 percent average annual growth rate forecast during the 2019 IRP Process and results in lower total peak demand at the end of the study period. System growth is driven by customer additions. Demand from customers using electric vehicles drives up residential and commercial use per customer in the second half of the study period.

The 2021 IRP Natural Gas Base Demand Forecast before additional conservation for both energy and peak demand is also lower than forecast during the 2019 IRP Process. However, for energy, the average annual growth rate (0.8 percent) is higher compared to the 2019 IRP Process (0.7 percent). For peak demand, the average annual growth rate in the 2021 IRP forecast is the same as that in the 2019 IRP Process (0.8 percent). Lower residential customer counts, lower residential use per customer, lingering COVID-19 effects, and the inclusion of recent data on cold weather days in calculating weather sensitivity reduced demand.

In this IRP, the Base Demand Forecast is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the 30 years ending in 2019. For the 2021 IRP, the natural gas and electric analysis included a temperature sensitivity on demand. PSE proposed three alternative temperature assumptions to stakeholders, and

stakeholders selected the temperature assumption with the greatest warming trend. This sensitivity has temperatures warming over time following the trend of one model that the Northwest Power and Conservation Council is using in its climate analyses. More information on this sensitivity can be found in Chapter 5, Key Analytical Assumptions, and the related demand forecast is discussed later in this chapter.

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low Forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast. For the High and Low Demand Forecasts, historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

CONSERVATION IMPACTS. Demand is reduced significantly when forward projections of additional conservation savings are applied, as shown in Figure 6-1. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most cost-effective amount of conservation to include in the resource plan.

NOTE: Throughout this chapter, charts labeled “before additional DSR” include only demand-side resource (DSR) measures implemented before the study period begins in 2022. Charts labeled “after applying DSR” include the cost-effective amount of DSR identified in the 2021 IRP.

Figure 6-1: Effect of Conservation Impacts on Demand Forecasts

2021 IRP Base Forecast at End of Forecast Period	Before Additional DSR	After Applying DSR
Electric Energy Demand (aMW) (2045)	3,316	2,604
Electric Peak Demand (MW) (2045)	6,159	4,966
Natural Gas Energy Demand (Mdth) (2041)	112,918	100,678
Natural Gas Peak Demand (Mdth) (2041)	1,130	1,019

2. ELECTRIC DEMAND FORECAST

Highlights of the IRP Base, High and Low Demand Forecasts developed for the electric service area are presented below in Figures 6-2 through 6-5. The population and employment assumptions for all three forecasts are summarized in the section titled “Details of Electric Forecast” and explained in detail in Appendix F, Demand Forecasting Models.

Only DSR measures implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Energy Demand

In the 2021 IRP Base Demand Forecast, energy demand before additional DSR is expected to grow at an average rate of 1.2 percent annually from 2022 to 2045, increasing energy demand from 2,500 aMW in 2022 to 3,316 aMW in 2045.

Residential and commercial demand are driving the growth in total energy. Excluding losses, these customer classes are projected to represent 50 percent and 38 percent of demand in 2022, respectively. On the residential side, use per customer is expected to be relatively flat for the short term but to grow over time, mainly due to the adoption of electric vehicles. This, plus population growth, is driving residential energy demand. On the commercial side, use per customer is relatively flat as well, with a small amount of growth in the later part of the forecast due to electric vehicle growth. Rising customer counts therefore drive much of the growth.

The 2021 IRP High Demand Forecast projects an average annual growth rate (AARG) of 1.6 percent; the Low Demand Forecast projects 0.9 percent.

Figure 6-2: Electric Energy Demand Forecast before Additional DSR

Base, High and Low Scenarios (aMW)

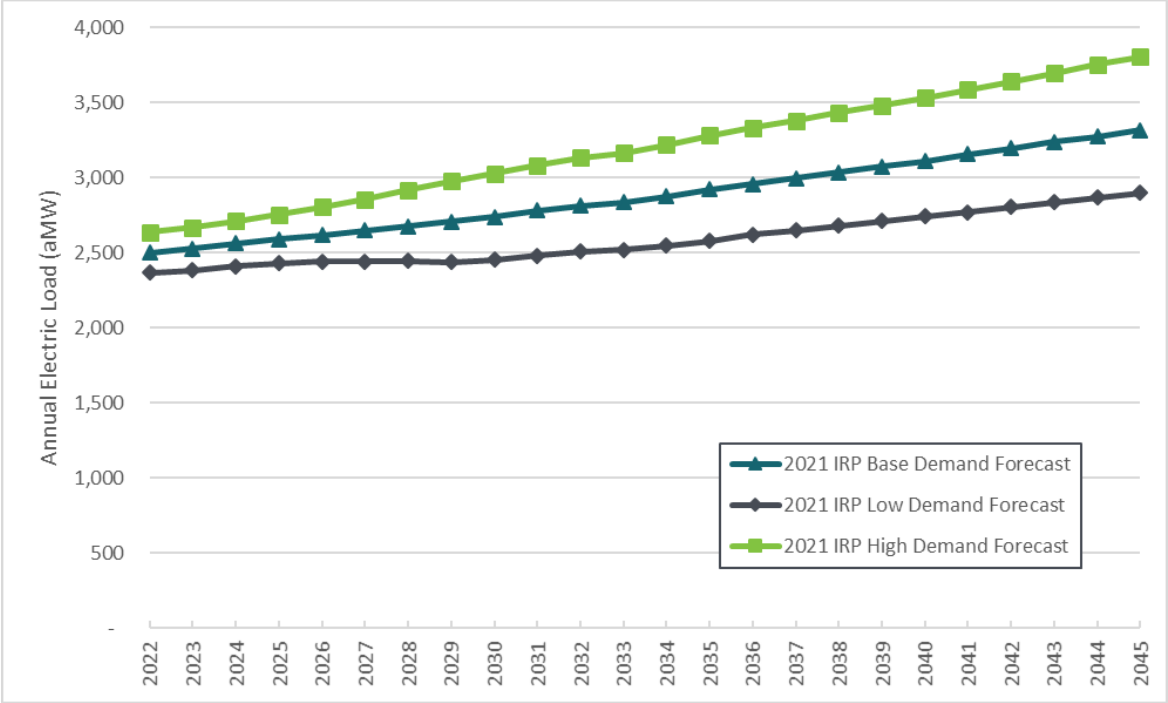


Figure 6-3: Electric Energy Demand Forecast before Additional DSR (Table)

Base, High and Low Scenarios

2021 IRP ELECTRIC ENERGY DEMAND FORECAST SCENARIOS (aMW)							
Scenario	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
2021 IRP Base Demand Forecast	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
2021 IRP High Demand Forecast	2,636	2,753	3,029	3,281	3,531	3,803	1.6%
2021 IRP Low Demand Forecast	2,367	2,429	2,454	2,580	2,742	2,897	0.9%

Electric Peak Demand

PSE is a winter peaking utility, meaning that the one hour during the year with the highest demand occurs during the winter. The capacity expansion model analyzes winter peaks. However, summer peaks are growing with warming summer temperatures and increased saturation of air conditioning in the region. Different types of supply-side or demand-side resources may better meet a summer or a winter peak. Therefore, PSE considers demand during all hours of the year in the resource adequacy modeling to help determine the best resources to meet load from our customers. This section describes the winter and summer electric peaks.

Winter Electric Peak Demand

The normal electric winter peak hour demand is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is a winter peaking utility, this peak has historically occurred in December but is occurring in other winter months as well. The 2021 IRP Base Demand Forecast shows a 1.2 percent average annual growth rate for peak demand; this would increase peak demand from 4,687 MW in 2022 to 6,159 MW in 2045.

The 2021 IRP High Demand Forecast shows an average annual peak demand growth rate of 1.5 percent, and the Low Demand Forecast shows a 0.9 percent average annual growth rate.

Figure 6-4: Winter Electric Peak Demand Forecast before Additional DSR
Base, High and Low Scenarios, Hourly Annual Peak (MW)

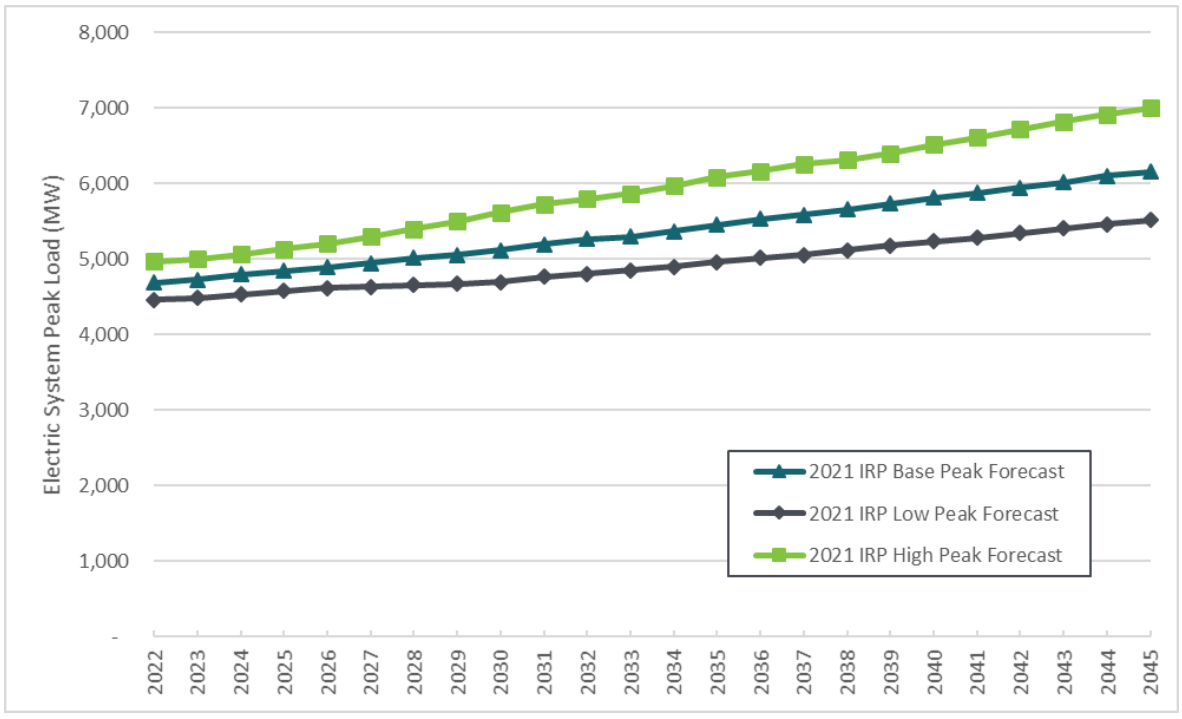
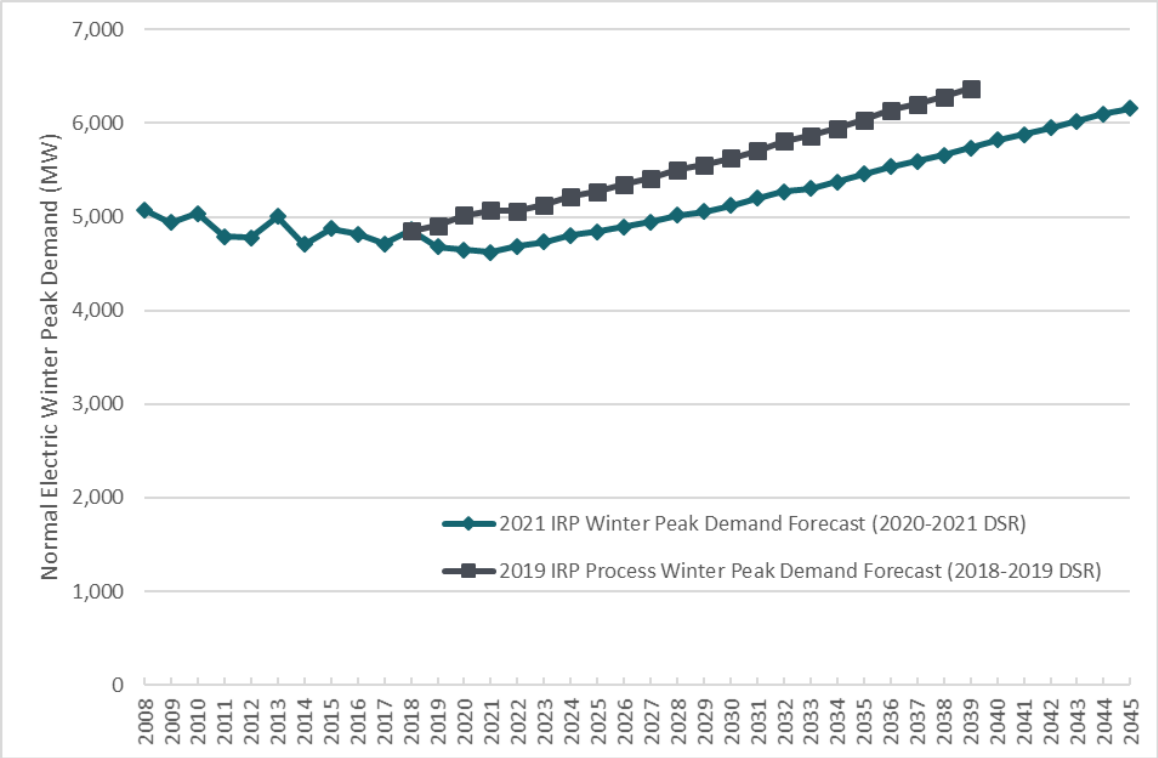


Figure 6-5: Winter Electric Peak Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (MW)

2021 IRP WINTER ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW)							
Scenario	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
2021 IRP Base Demand Forecast	4,687	4,844	5,123	5,455	5,819	6,159	1.2%
2021 IRP High Demand Forecast	4,972	5,138	5,622	6,085	6,521	7,001	1.5%
2021 IRP Low Demand Forecast	4,466	4,581	4,697	4,966	5,240	5,519	0.9%

Peak demand in the 2021 IRP Base Demand Forecast is lower at the end of the study period (6,159 MW in 2040) compared to the 2019 IRP Process (6,370 MW in 2039). Additionally, the 2021 IRP Peak Demand Forecast has a slower average annual growth rate (1.2 percent) compared to the 2019 IRP Process (1.3 percent). The 2021 IRP Peak Demand Forecast projects slower growth than the 2019 IRP Process Peak Demand Forecast because the 2021 IRP Demand Forecast grows at a slower rate than the 2019 IRP Process due to slower anticipated customer growth (particularly commercial) and lower projected use per customer in all non-residential classes. Observed actual residential customers and sales growth in 2018 and 2019 offset the non-residential trends; however, the downward growth drivers related to lower commercial usage and COVID-19 result in a lower long-term growth rate.

Figure 6-6: Winter Electric Peak Demand Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Hourly Annual Peak (23 Degrees, MW)



Summer Electric Peak Demand

The normal electric summer peak hour demand is modeled using 93 degrees Fahrenheit as the design temperature. Summer peaks typically occur in July or August. Figure 6-7 shows the 2021 IRP Base Peak Demand Forecast for the winter and the summer. The 2021 IRP Base summer peak demand forecast has an average annual growth rate of 1.7 percent. This increases the summer peak demand from 3,515 MW in 2022 to 5,183 MW in 2045. Because the summer peak forecast does not exceed the winter peak forecast in the timeframe shown, it is assumed that PSE will continue to be a winter peaking utility for the planning period of this IRP.

Figure 6-7: Winter and Summer Electric Peak Demand Forecasts before Additional DSR Base Scenario, Hourly Annual Peak (MW)

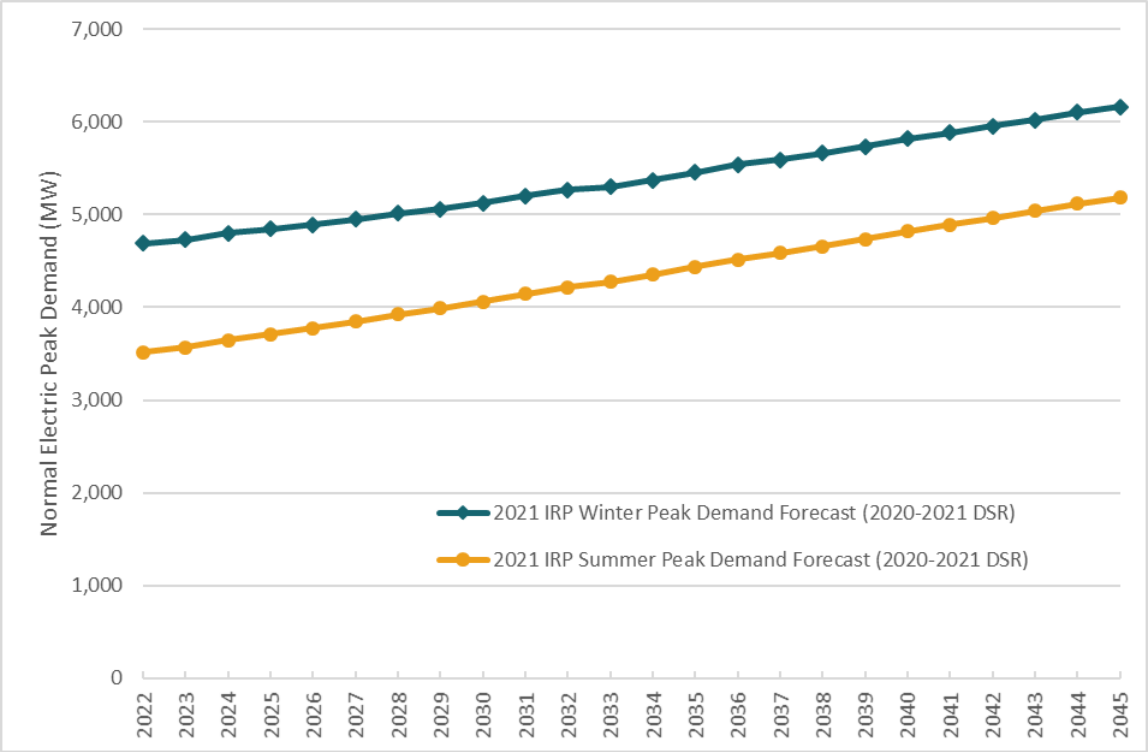


Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2020 and 2021, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2022 to 2045.

However, PSE also examines the effects of conservation on the energy and peak demand over the full planning horizon. Forecasts with conservation are used internally at PSE for financial and system planning decisions. To illustrate conservation impacts, the cost-effective demand-side resources identified in this IRP[1] are applied to the Base Scenario energy and peak demand forecasts for 2022 to 2045. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The results are illustrated in Figures 6-8 and 6-9, below.

[1] / *For demand-side resource analysis, see Chapter 8, Electric Analysis, and Appendix E, Conservation Potential Assessment and Demand Response Assessment.*

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied to the energy demand forecast:

- Electric energy demand in 2045 is reduced 21 percent to 2,604 aMW.
- Electric energy demand after DSR grows at an average annual rate of 0.23 percent from 2022 to 2045.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 portfolio analysis are applied to the peak demand forecast:

- Electric system peak demand in 2045 is reduced 19 percent to 4,966 MW.
- Electric system peak demand after DSR grows at an average annual rate of 0.3 percent from 2022 to 2045.

Figure 6-8: Electric Energy Demand Forecast (aMW), before Additional DSR and after Applying DSR

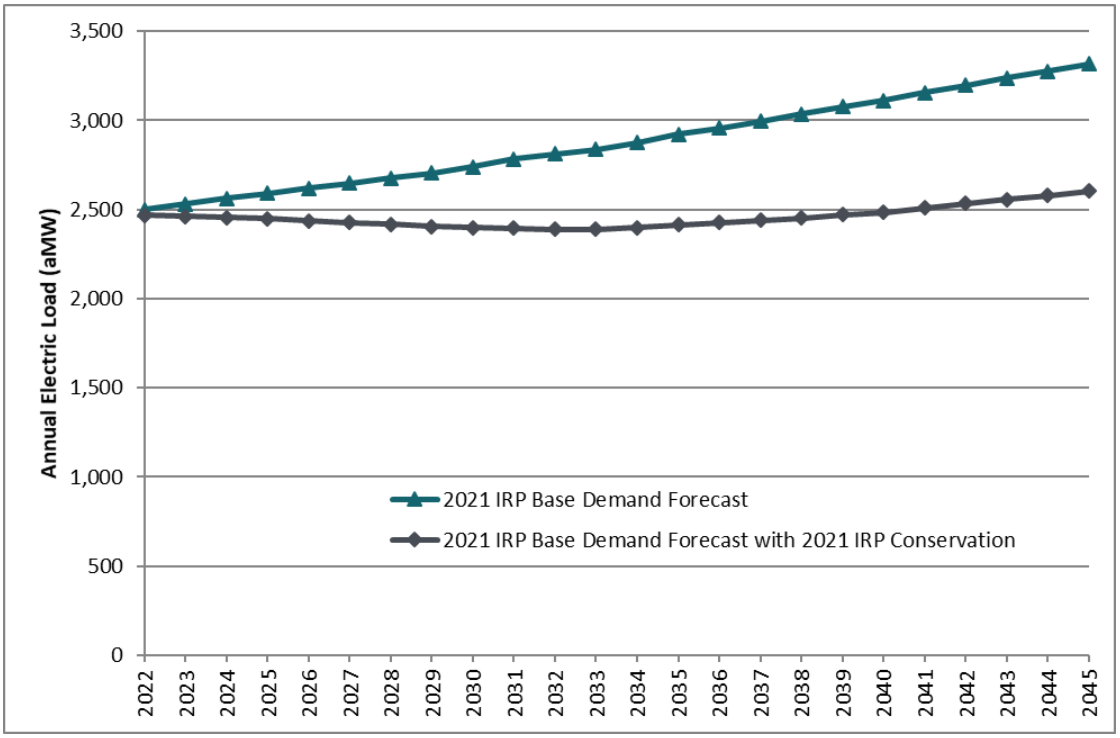
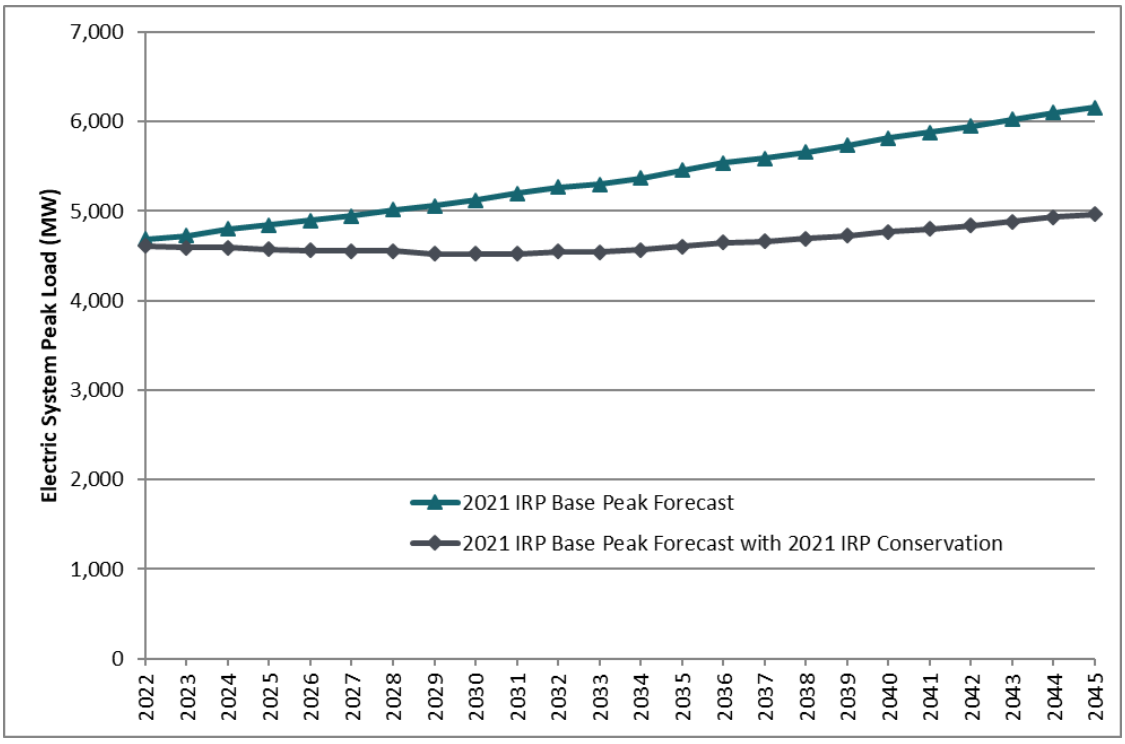


Figure 6-9: Electric Peak Demand Forecast (MW), before Additional DSR and after Applying DSR



Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.0 percent per year on average, from 1.21 million customers in 2022 to 1.53 million customers in 2045. This is slower than the average annual growth rate of 1.2 percent projected in the 2019 IRP Process Base Demand Forecast.

Residential customers are driving the overall customer count increase, since they are projected to represent 88 percent of PSE's electric customers in 2022. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2023 to 2045. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.9 percent. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service area shifts toward more commercial and less industrial industries.

Figure 6-10: December Electric Customer Counts by Class, 2021 IRP Base Demand Forecast

2021 IRP DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST							
Class	2022	2025	2030	2035	2040	2045	AARG 2022-2045
Total	1,210,701	1,253,182	1,324,465	1,395,434	1,463,388	1,529,051	1.0%
Residential	1,066,293	1,103,799	1,167,538	1,230,936	1,291,536	1,349,980	1.0%
Commercial	133,023	137,547	144,357	151,236	157,975	164,647	0.9%
Industrial	3,249	3,193	3,106	3,023	2,948	2,882	-0.5%
Other	8,130	8,643	9,464	10,239	10,929	11,542	1.5%

Electric Demand by Class

Over the next 20 years, the residential and commercial classes are both expected to have positive demand growth, with the residential class growing faster than the commercial class, before conservation. Residential class demand growth is driven by new additional customers and projected adoption of electric vehicles. Commercial class demand growth is driven by growth in the region's technology sector, which also increases the need for support services such as health care, retail, education and other public services.

Figure 6-11: Electric Energy Demand by Class,
2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND BY CLASS, 2021 IRP BASE DEMAND FORECAST (aMW)							
Class	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
Total	2,500	2,592	2,740	2,921	3,110	3,316	1.2%
Residential	1,248	1,300	1,392	1,497	1,609	1,722	1.4%
Commercial	954	987	1,036	1,100	1,167	1,249	1.2%
Industrial	120	121	119	117	115	114	-0.2%
Other	8	8	8	8	7	7	-0.7%
Losses	170	176	186	199	211	226	-

Electric Use per Customer

Residential use per customer[2] before conservation is expected to decline in the short term but is forecast to grow over the long term. Near-term efficiency gains and multifamily housing growth will continue to reduce electric use per customer, but the forecast projects that the increasing adoption of electric vehicles will outweigh this and create slightly positive growth, especially in the later part of the forecast. Commercial use per customer is expected to decline in the short term, due to efficiency gains as well as lingering effects from the pandemic on the commercial sector. Commercial use per customer has some positive growth in the long term due to increasing electric vehicle growth.

Figure 6-12: Electric Use per Customer, 2021 IRP Base Demand Forecast before Additional DSR

2021 IRP ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh/CUSTOMER)							
Type	**2022**	**2025**	**2030**	**2035**	**2040**	**2045**	**AARG 2022-2045**
Residential	10.3	10.4	10.5	10.7	11.0	11.2	0.4%
Commercial	63.1	63.1	63.0	63.9	65.1	66.6	0.2%
Industrial	321.9	330.5	333.6	337.3	341.4	344.7	0.3%

2 / Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.

Electric Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 6-13. Demand share by class is shown in Figure 6-14. The residential class is expected to increase as a percent of both total customers and total demand, and the commercial class is expected to decline as a percent of both.

Figure 6-13: December Electric Customer Count Share by Class, 2021 IRP Base Demand Forecast

ELECTRIC CUSTOMER COUNT SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	88.1%	88.3%
Commercial	11.0%	10.8%
Industrial	0.3%	0.2%
Other	0.7%	0.8%

Figure 6-14: Electric Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

ELECTRIC DEMAND SHARES BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2045**
Residential	49.9%	51.9%
Commercial	38.1%	37.6%
Industrial	4.8%	3.4%
Other	0.3%	0.2%
Losses	6.8%	6.8%

3. NATURAL GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's natural gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized in the section titled "Details of the Natural Gas Forecast" and explained in detail in Appendix F, Demand Forecasting Models.

Only demand-side resources implemented through December 2021 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Natural Gas Energy Demand

The 2021 IRP Natural Gas Base Demand Forecast is a forecast of both firm and interruptible demand, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For delivery system planning, however, transport demand must be included in total demand; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2021 IRP Base Demand Forecast, natural gas energy demand before additional DSR is projected to grow 0.8 percent per year on average from 2022 to 2041; this would increase demand from 96,156 MDth in 2022 to 112,918 MDth in 2041. This is slightly higher than the annual growth rate of 0.7 percent in the 2019 IRP Process Base Demand Forecast. While the growth rate is higher, the levels of demand are lower in the 2021 IRP Base Demand Forecast than in the 2019 IRP Process Demand Forecast because lower residential customer additions, lower residential usage in the first half of the forecast and lingering COVID-19 pandemic effects lower demand in the first part of the forecast, compared to the 2019 IRP Process Forecast.

Before additional DSR, the 2021 IRP High Natural Gas Demand Forecast projects an average annual growth rate of 1.4 percent; the Low Natural Gas Demand Forecast projects a growth rate of 0.2 percent per year.

Figure 6-15: Natural Gas Energy Demand Forecast before Additional DSR
Base, High and Low Scenarios, without Transport Load (MDth)

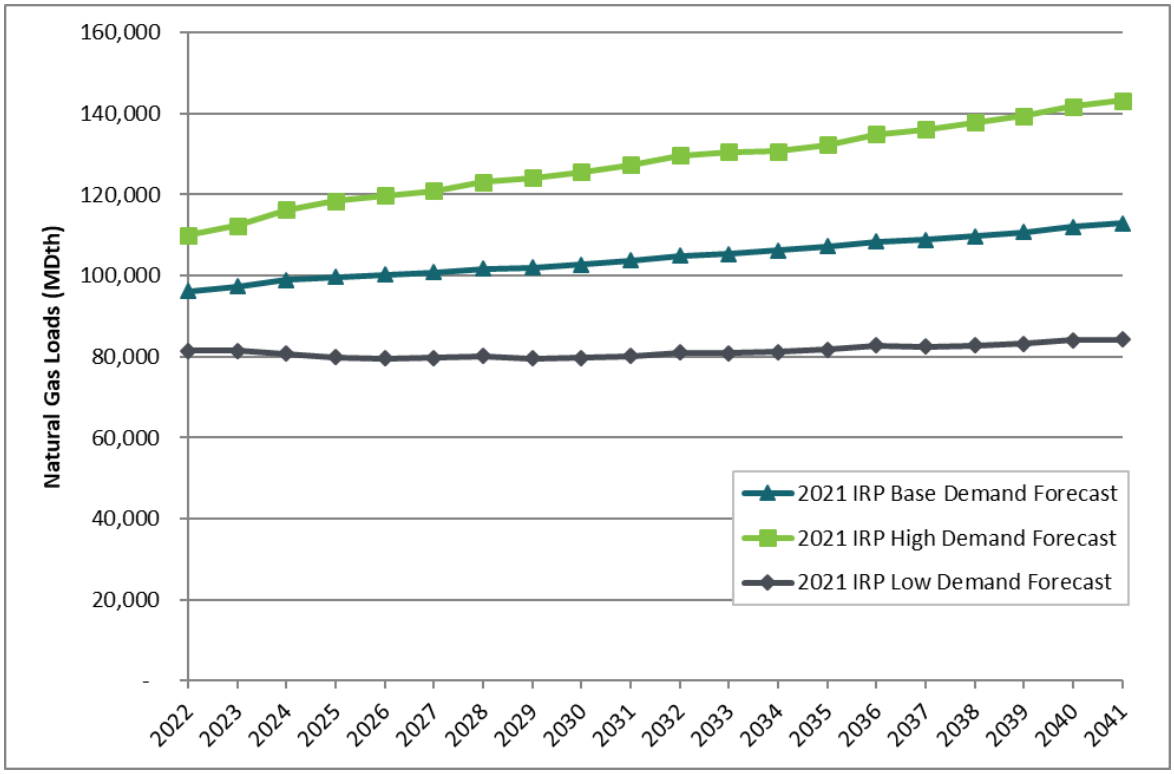


Figure 6-16: Natural Gas Energy Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios without Transport (MDth)

2021 IRP NATURAL GAS ENERGY DEMAND FORECAST SCENARIOS (MDth), WITHOUT TRANSPORT						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	96,156	99,653	102,769	107,195	112,918	0.8%
2021 IRP High Demand Forecast	110,024	118,424	125,542	132,321	143,261	1.4%
2021 IRP Low Demand Forecast	81,498	79,852	79,680	81,707	84,266	0.2%

Natural Gas Peak Demand

The natural gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day. Only firm sales customers are included when forecasting peak natural gas demand; transportation and interruptible customers are not included.

For peak natural gas demand, the 2021 IRP Base Demand Forecast projects an average increase of 0.8 percent per year from 2022 to 2041; peak demand would rise from 967 MDth in 2022 to 1,130 MDth in 2041. The High Demand Forecast projects a 1.1 percent annual growth rate, and the Low Demand Forecast projects 0.6 percent.

Figure 6-17: Natural Gas Peak Day Demand Forecast before Additional DSR Base, High and Low Scenarios (13 Degrees, MDth)

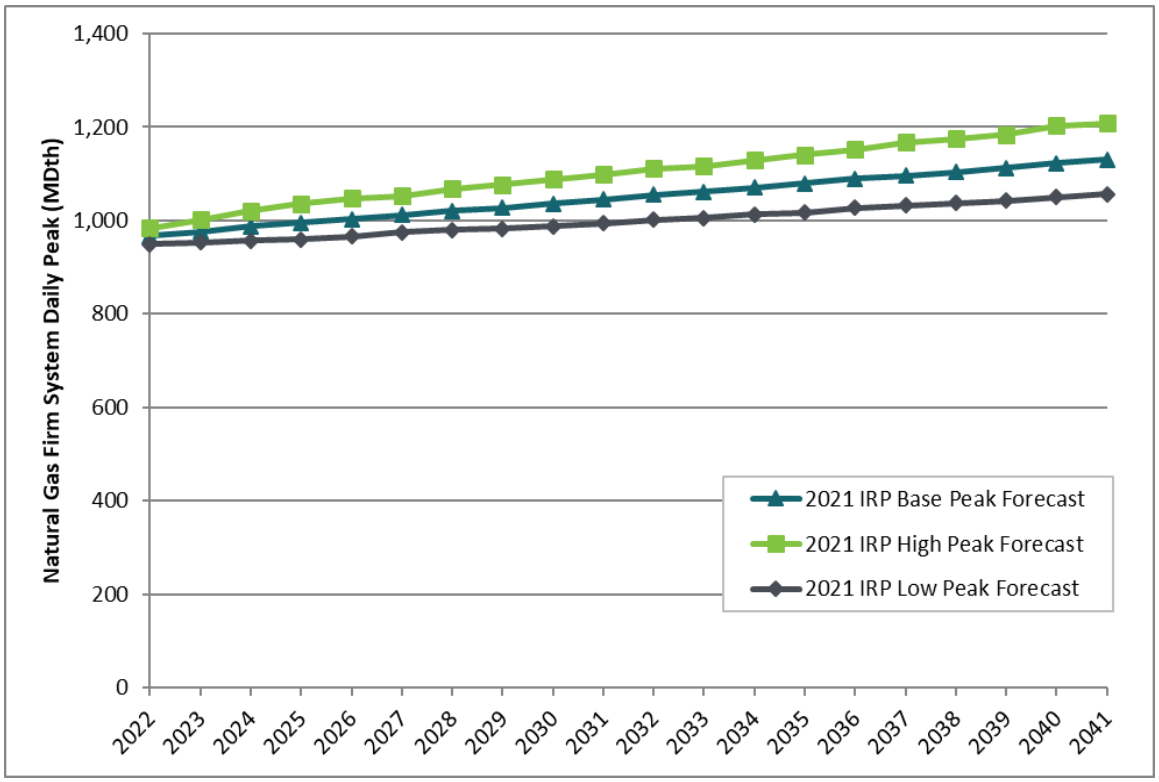


Figure 6-18: Natural Gas Peak Day Demand Forecast before Additional DSR (Table)
Base, High and Low Scenarios (13 Degrees, MDth)

2021 IRP FIRM NATURAL GAS PEAK DAY FORECAST SCENARIOS (MDth)						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	967	995	1,036	1,079	1,130	0.8%
2021 IRP High Demand Forecast	984	1,036	1,088	1,141	1,208	1.1%
2021 IRP Low Demand Forecast	950	960	988	1,017	1,056	0.6%

The peak demand growth rate in the 2021 Base Demand Forecast is the same as the growth rate in the 2019 IRP Process (0.8 percent), but the highest levels of peak are lower in the 2021 IRP. This is partially due to the lower customer forecast, especially in the latter years of the forecast period, and the lingering effects of the COVID-19 pandemic in the first few years of the forecast period. Also, cold winter weather in 2018 and 2019 allowed the 2021 IRP natural gas peak forecast model to better capture the sensitivity of customers to cold weather.

Figure 6-19: Firm Natural Gas Peak Day Forecast before Additional DSR
2021 IRP Base Scenario versus 2019 IRP Process Base Scenario
Daily Annual Peak (13 Degrees, MDth)

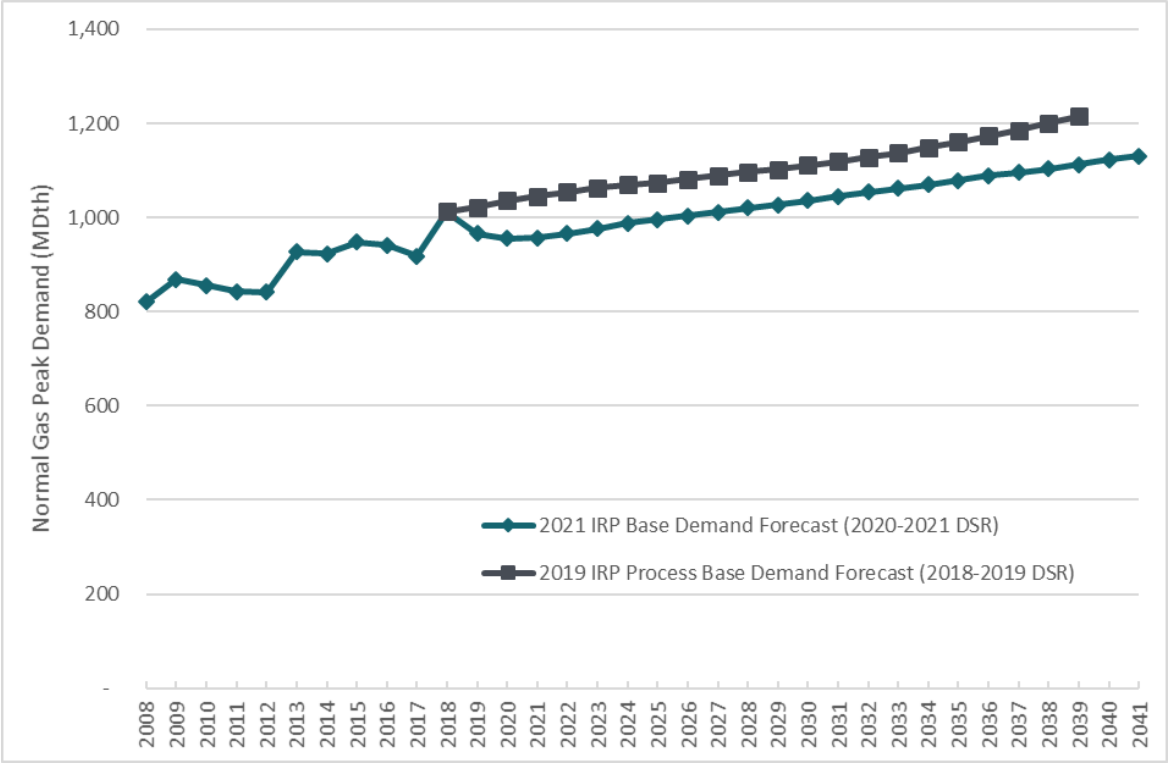


Illustration of Conservation Impacts

As explained at the beginning of the chapter, the natural gas demand forecasts include only demand-side resources implemented through December 2021, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the energy and peak forecasts, the cost-effective amount of DSR determined in this IRP[3] is applied to the energy demand (without transport) and peak demand forecast for 2022 to 2041. To account for the 2017 General Rate Case, an additional 5 percent of conservation is also applied for that period. Forecasts with conservation are used internally at PSE for financial and system planning decisions. The results are illustrated in Figures 6-20 and 6-21, below.

DSR IMPACT ON ENERGY DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas energy demand in 2041 is reduced 10.8 percent to 100,678 Mdth.
- Natural gas energy demand grows at an average annual rate of 0.26 percent from 2022 to 2041.

DSR IMPACT ON PEAK DEMAND. When the DSR bundles chosen in the 2021 IRP portfolio analysis are applied:

- Natural gas system peak demand in 2041 is reduced 9.8 percent to 1,019 Mdth.
- Natural gas system peak demand grows at an average annual rate of 0.3 percent from 2022 to 2041.

3 / For demand-side resource analysis, see Chapter 9, Natural Gas Analysis, and Appendix E, Conservation Potential Assessment.

Figure 6-20: Natural Gas Base Demand Forecast for Energy, before Additional DSR and after Applying DSR

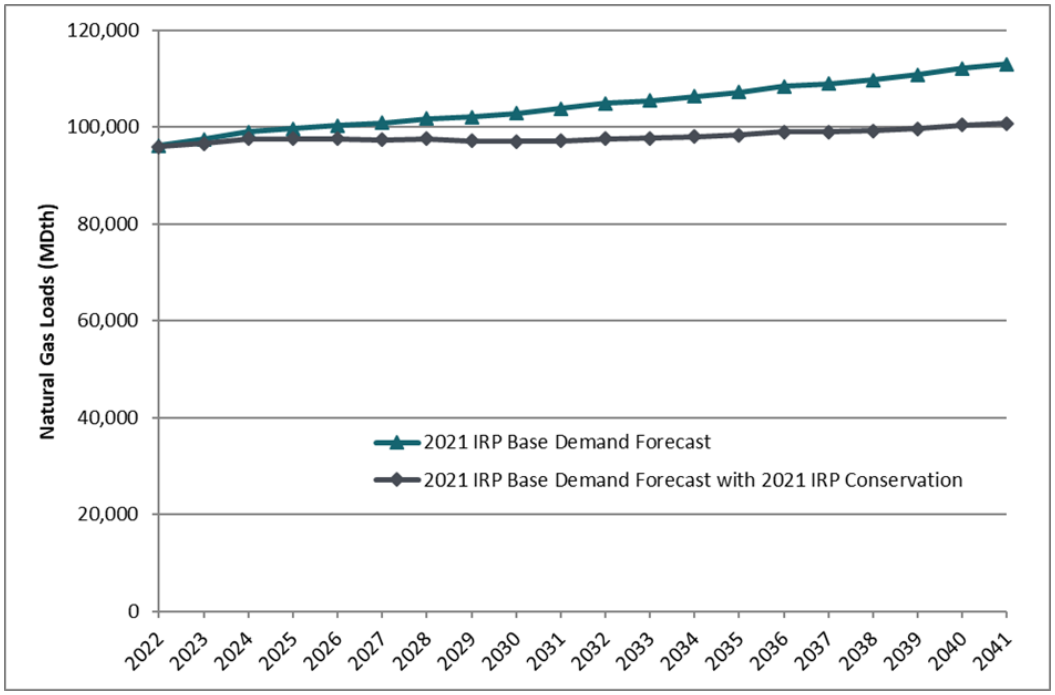
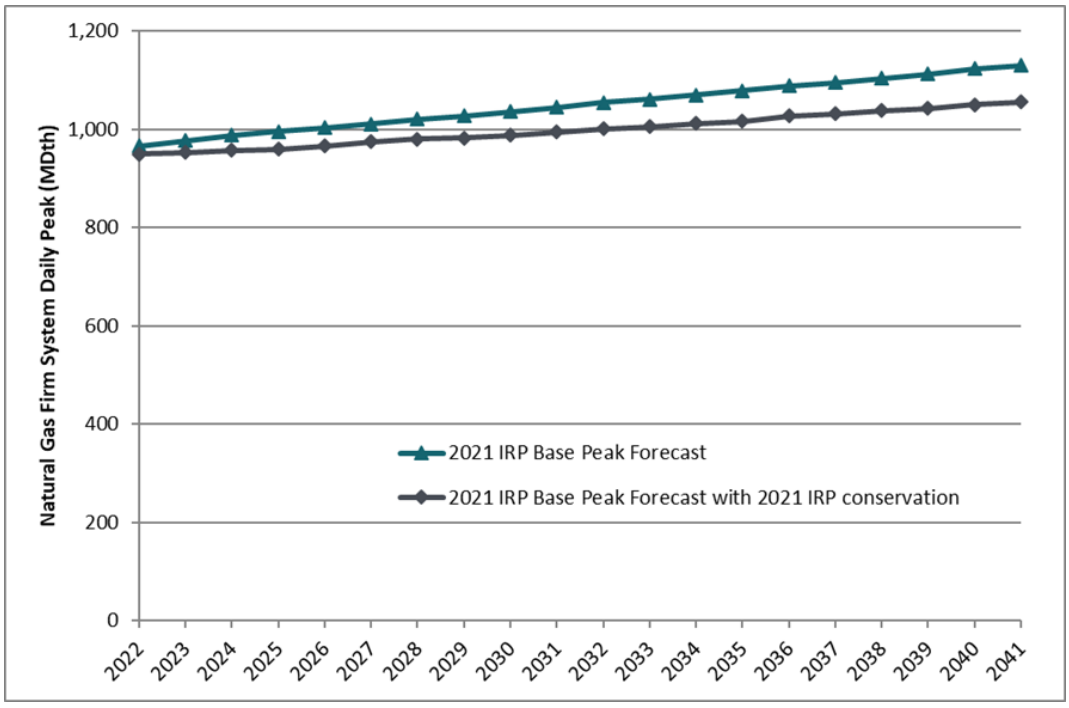


Figure 6-21: Natural Gas Peak Day Base Demand Forecast, before Additional DSR and after Applying DSR



Details of Natural Gas Forecast

Natural Gas Customer Counts

The Base Demand Forecast projects the number of natural gas customers will increase at a rate of 1.0 percent per year on average between 2022 and 2041, reaching 1.059 million customers by the end of the forecast period for the system as a whole. Overall, customer growth is slower than the 1.3 percent average annual growth rate projected in the 2019 IRP Process for 2020 to 2039.

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE's natural gas sales customers. Residential customer counts are expected to grow at an average annual rate of 1.0 percent from 2022 to 2041. The next largest group, commercial customers, is expected to grow at an average annual rate of 0.6 percent from 2022 to 2041. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Figure 6-22: December Natural Gas Customer Counts by Class, 2021 IRP Base Demand Forecast

DECEMBER NATURAL GAS CUSTOMER COUNTS BY CLASS 2021 IRP BASE DEMAND FORECAST						
Customer Type	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
Residential	817,317	845,918	892,765	939,222	993,155	1.0%
Commercial	57,264	58,444	60,095	61,734	63,666	0.6%
Industrial	2,244	2,191	2,103	2,016	1,910	-0.8%
Total Firm	876,825	906,553	954,963	1,002,972	1,058,731	1.0%
Interruptible	145	129	102	74	41	-6.4%
Total Firm & Interruptible	876,970	906,682	955,065	1,003,046	1,058,772	1.0%
Transport	225	225	225	225	225	0.0%
System Total	877,195	906,907	955,290	1,003,271	1,058,997	1.0%

Natural Gas Use per Customer

Table 6-23 below shows all firm use per customer at the meter.[4] Residential use per customer before conservation is slowly declining, showing a -0.1 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.6 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years and is expected to stay relatively flat. Note the commercial and industrial classes do not include interruptible or transport class usage. These classes can have very different sized customers and therefore the use per customer value can be skewed by very large customers.

Figure 6-23: Natural Gas Use per Customer before Additional DSR
2021 IRP Gas Base Demand Forecast

NATURAL GAS USE PER CUSTOMER (THERMS/CUSTOMER) 2021 IRP BASE DEMAND FORECAST						
Customer	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
Residential	784	783	766	763	765	-0.1%
Commercial	4,960	5,122	5,234	5,376	5,553	0.6%
Industrial	10,685	10,691	10,692	10,692	10,694	0.0%

4 / Use per customer is defined as billed energy sales per customer, that is, the amount of energy consumed at the meter.

Natural Gas Demand by Class

Total energy demand, including transport, is expected to increase at an average rate of 0.7 percent annually between 2022 and 2041. Residential demand, which is forecast to represent 53 percent of demand in 2022, is expected to increase on average by 0.9 percent annually during the forecast period. Commercial demand, which is forecast to represent 24 percent of demand in 2022, is expected to increase 1.2 percent on average annually.

Population growth is driving residential demand growth. Commercial demand growth is driven by increases in both customer counts and use per customer. Demand in the industrial and interruptible sectors is expected to decline as manufacturing employment in the Puget Sound area continues to slow. Demand from the transport class is expected to grow slowly over time.

Figure 6-24: Natural Gas Energy Demand by Class (MDth), 2021 IRP Base Demand Forecast before Additional DSR

NATURAL GAS DEMAND (MDth) BY CLASS 2021 IRP BASE DEMAND FORECAST						
Class	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
Residential	62,949	65,092	67,228	70,454	74,690	0.9%
Commercial	28,039	29,645	31,133	32,857	34,991	1.2%
Industrial	2,390	2,335	2,242	2,149	2,038	-0.8%
Total Firm	93,379	97,072	100,604	105,460	111,719	0.9%
Interruptible	2,585	2,382	1,960	1,520	974	-5.0%
Total Firm and Interruptible	95,964	99,454	102,564	106,981	112,692	0.8%
Transport	22,169	22,445	22,414	22,574	22,948	0.2%
System Total before Losses	118,133	121,899	124,978	129,555	135,641	0.7%
Losses	237	244	250	260	272	-
System Total	118,370	122,143	125,228	129,815	135,912	0.7%

Natural Gas Customer Count and Energy Demand Share by Class

Customer counts as a percent of PSE's total natural gas customers are shown in Figure 6-25. Demand share by class is shown in Figure 6-26.

Figure 6-25: Natural Gas Customer Count Share by Class
2021 IRP Base Demand Forecast

NATURAL GAS CUSTOMER COUNT SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2041**
Residential	93.2%	93.8%
Commercial	6.5%	6.0%
Industrial	0.3%	0.2%
Interruptible	0.02%	0.004%
Transport	0.03%	0.02%

Figure 6-26: Natural Gas Demand Share by Class, 2021 IRP Base Demand Forecast before Additional DSR

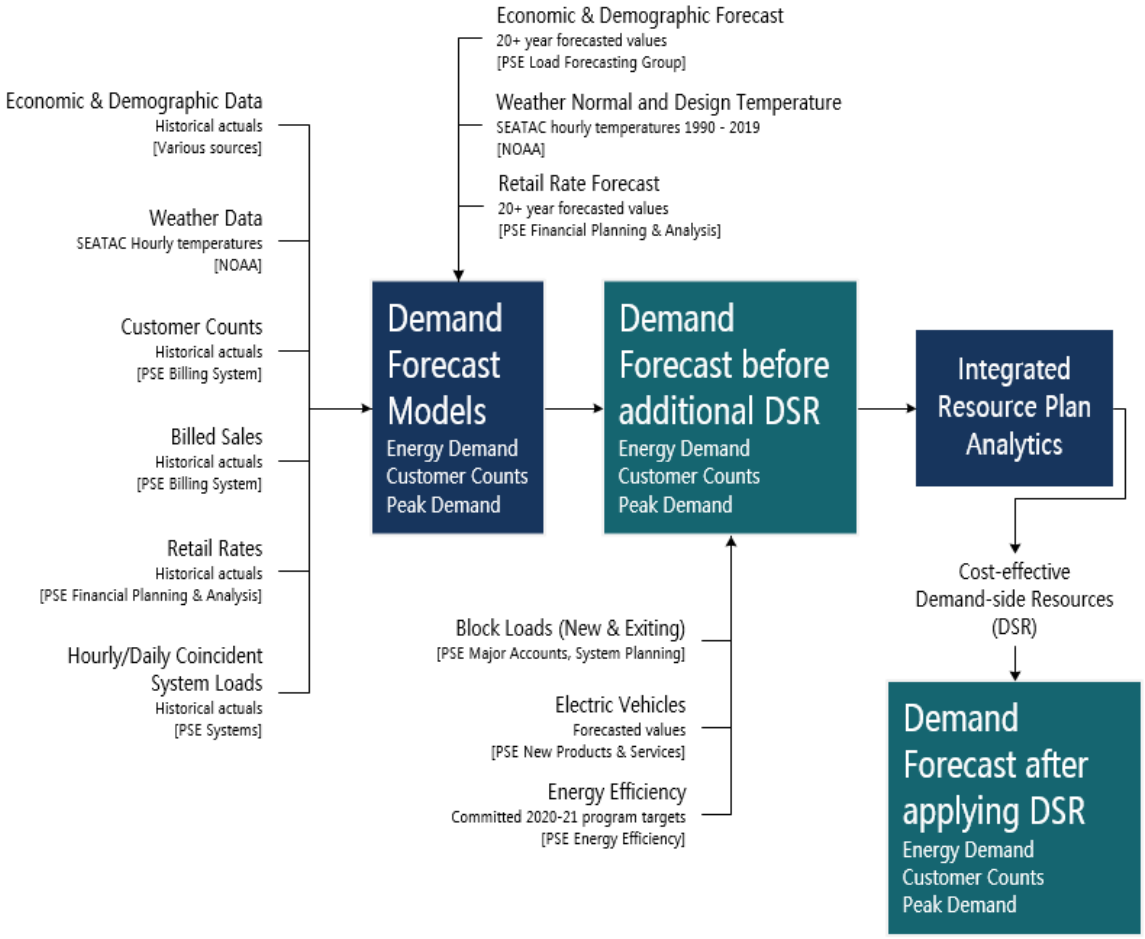
NATURAL GAS DEMAND SHARE BY CLASS, 2021 IRP BASE DEMAND FORECAST		
Class	**Share in 2022**	**Share in 2041**
Residential	53.2%	55.0%
Commercial	23.7%	25.7%
Industrial	2.0%	1.5%
Interruptible	2.2%	0.7%
Transport	18.7%	16.9%
Losses	0.2%	0.2%

4. METHODOLOGY

Forecasting Process

PSE's regional economic and demographic model uses both national and regional data to produce a forecast of total employment, types of employment, unemployment, personal income, households and consumer price index (CPI) for both the PSE electric and natural gas service territories. The regional economic and demographic data used in the model are built up from county level or metropolitan statistical area (MSA) level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. The demand forecasting process is illustrated in Figure 6-27, and the sources for economic and demographic input data are listed in Figure 6-28.

Figure 6-27: PSE Demand Forecasting Process



To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes and/or service levels are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport (customers purchasing their power not from PSE but from third-party suppliers).



- Natural gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers
"Transport" in the electric and natural gas industries has historically referred to customers that acquire their own electricity or natural gas from third-party suppliers and rely on the utility for distribution service. It does not refer to natural gas fueled vehicles or electric vehicles.

Multivariate time series econometric regression equations are used to derive historical relationships between trends and drivers, which are then employed to forecast the number of customers and use per customer by class or service level. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population, unemployment rates, retail rates, personal income, weather, total employment, manufacturing employment, consumer price index (CPI) and U.S. Gross Domestic Product (GDP). Demand, which is presented in this chapter, is calculated from sales and includes transmission and distribution losses in addition to sales. Weather inputs are based on temperature readings from Sea-Tac Airport. Peak system demand is also projected by examining the historical relationship between actual peaks, temperature at peaks, and the economic and demographic impacts on system demand.

> > > See Appendix F, Demand Forecasting Models*, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts and peak loads for electricity and natural gas; hourly distribution of electric demand; and forecast uncertainty.*

Figure 6-28: Sources for U.S. and Regional Economic and Demographic Data

DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL	
County-level Data	**Source**
Labor force, employment, unemployment rate	U.S. Bureau of Labor Statistics (BLS) www.bls.gov
Total non-farm employment, and breakdowns by type of employment	WA State Employment Security Department (WA ESD), using data from Quarterly Census of Employment and Wages esd.wa.gov/labormarketinfo
Personal income	U.S. Bureau of Economic Analysis (BEA) www.bea.gov
Wages and salaries	
Population	WA State Employment Security Department (WA ESD) esd.wa.gov/labormarketinfo/report-library
Households, single- and multi-family	U.S. Census www.census.gov
Household size, single- and multi-family	
Housing permits, single- and multi-family	U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / Building Industry Association of Washington (BIAW) www.biaw.com
Aerospace employment	Puget Sound Economic Forecaster www.economicforecaster.com
U.S.-level Data	**Source**
GDP	Moody's Analytics www.economy.com
Industrial Production Index	
Employment	
Unemployment rate	
Personal income	
Wages and salary disbursements	
Consumer Price Index (CPI)	
Housing starts	
Population	
Conventional mortgage rate	
T-bill rate, 3 months	

High and Low Scenarios

PSE also develops high and low growth scenarios by performing stochastic simulations with stochastic outputs from PSE's economic and demographic model, using historic weather to predict future weather.

- The natural gas high and low scenarios were modelled using 250 stochastic simulations.
- The electric high and low scenarios were created with an additional 60 simulations (for a total of 310), in order to capture variation in electric vehicle loads. The electric modeling also varied the seasonal design peak temperature.

The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment and income. They also vary the equation coefficients around the standard error of the coefficient to include potential model coefficient errors. In the electric scenarios, EV assumptions were held constant in 250 of the scenarios; a high EV forecast was applied to 30 scenarios; and a low EV forecast was applied to 30 scenarios. The high and low EV forecasts were derived using assumptions from the high and low EV scenarios in the July 2020 Pacific Northwest National Lab report, *Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid*. (The base EV forecast is described in more detail in Section 5 of this chapter, Chapter 5, Key Analytical Assumptions, and Chapter 4, Planning Environment.)

High and low growth scenarios also use historic weather scenarios that can reflect higher or lower temperature conditions. Historic weather scenarios use one year of weather data randomly drawn between 1990 and 2019 in each of the simulations. In contrast, the "normal" weather used for the base scenario is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The low and high scenarios represent the 10th and 90th percentile of the simulations, respectively.

The high and low scenarios are run in the AURORA model to examine how a portfolio would change with high and low growth. The 310 electric stochastic scenarios are run in the AURORA portfolio model to test the robustness of the portfolio under various conditions. The 250 natural gas stochastic scenarios are run in SENDOUT. Detailed descriptions of the stochastics are available in Chapter 8, Electric Analysis, and Chapter 9, Natural Gas Analysis.

> > > See Appendix F, Demand Forecasting Models*, for a detailed discussion of the stochastic simulations.*

Resource Adequacy Model Inputs

In addition to the stochastics used to create the high and the low scenarios, PSE also develops 88 electric demand draws for the resource adequacy (RA) model. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2017 is represented in the 88 demand draws. Since the RA model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. RA demand draws were created for the hydro years of 2027 to 2028 and 2031 to 2032.

Additionally, the RA model examines adequacy in each hour of a given future year; therefore, the RA model inputs are scaled to hourly demand using the hourly demand model, described in detail in Chapter 7, Resource Adequacy Analysis. To account for growth in electric vehicles, each of the 88 hourly demand forecasts was first created without electric vehicle demand. Then the hourly forecast of electric vehicle demand was added to each demand forecast, to create the final 88 hourly demand forecasts.

> > > See Chapter 7, Resource Adequacy Analysis *and* ***Appendix F, Demand Forecasting Models****, for detailed discussions of the hourly model.*

Temperature Sensitivity

PSE committed to run a future temperature sensitivity as part of the IRP. To that end, in addition to the definition of normal temperature used for the base energy demand model, PSE offered three alternative average temperature assumptions to the IRP stakeholders and asked them to select one of the options for further analysis. The three options used different future temperature assumptions, representing a wide range of future outcomes. PSE then ran a sensitivity based on the option chosen.

The three temperature sensitivities presented as options were:

1. **15-year normal temperature:** PSE currently uses a 30-year normal for the base demand forecast. That is, the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. This normal weather is held constant into the future. The 15-year normal would instead use the most recent 15 years of weather data to create average monthly weather, and that weather would be held constant into the future. Option 1 results in the least amount of future warming.
2. **Historical trended temperature:** PSE contracted with Itron to examine the historic warming trend in temperatures at Sea-Tac Airport. The warming trend at Sea-Tac was determined to be linear over time at 0.4 degrees Fahrenheit warming per decade. This warming trend was then projected linearly into the future. A detailed write-up of this analysis is presented in Appendix L, Temperature Trend Study. Option 2 results in more future warming than Option 1, but less than Option 3.
3. **Council climate model:** A recent project by Bonneville Power Administration, U.S. Army Corps of Engineers, and the Bureau of Reclamation produced downscaled climate models for the Northwest region. The Northwest Power and Conservation Council (NWPCC) has been working with three of these models (CanESM2_BCSD, CCSM4_BCSD and CNRM-CM5_MACA). Each of these models is on the Representative Concentration Pathway of 8.5; some would argue this is a "business as usual" pathway, while others would argue that this is a more extreme climate warming scenario. The three models represent different amounts of warming over time. PSE presented the NWPCC model with the middle amount of warming (CCSM4_BCSD) as an option, which results in 0.9 degrees Fahrenheit of warming per decade. Option 3 represents a more extreme warming trend than Option 2.

Figure 6-29 below further describes the three future temperature options that IRP stakeholders chose from for this sensitivity.

Figure 6-29: Attributes of Temperature Sensitivity Options Compared to the Base Demand Forecast Temperatures Used

	Future Weather in Base Demand Model	Temperature Sensitivity Option 1	Temperature Sensitivity Option 2	Temperature Sensitivity Option 3
Description	30-year normal temperature	15-year normal temperature	Historical temperature trend (developed by Itron)	Council climate model
General Modeling Approach	Industry standard approach of using last 30 years of data to create flat projected temperature	Same methodology as 30-year normal, but using last 15 years of data	Uses historical warming trend to forecast future warming	Global Climate Model down-scaled to Pacific Northwest region
Weather Station Used	Sea-Tac	Sea-Tac	Sea-Tac	Sea-Tac
Historical Sea-Tac Weather Used	Last 30 years	Last 15 years	Data back to 1950 to develop a trend, 30-year normal used to define the starting point for the trend	Uses historic year of 1987 to map forecasted daily min and max temperatures to hourly temperatures
Global Climate Model, down-scaling method, and Representative Climate Pathway (RCP) assumed	NA	NA	NA, results similar to RCP 4.5	CCSM4_BCSD (Community Climate Systems Model v4: Bias Corrected Spatial Disaggregation), RCP 8.5
Energy Demand Modeling Approach	Uses last 30 years of data to create flat projected temperature for future	Uses last 15 years of data to create flat projected temperature for future	Uses historical trend to forecast warming trend in the future. Uses the middle of the last 30 years of weather as a starting point for weather trend.	Draw a trend line through the future temperatures to get warming per year. Uses the middle of the last 30 years of weather as a starting point for weather trend.
Average Warming in the Forecast Period for Energy Demand Modeling	0º F per decade	0º F per decade	0.4º F per decade	0.9º F per decade

To incorporate the future temperature options into the demand forecast, they first had to be converted into heating degree days (HDDs) and cooling degree days (CDDs). Heating and cooling degree days are a measure of how much heating or cooling is expected to be done by electric or natural gas appliances in a given month. Additional information on how to calculate heating and cooling degree days and how they factor into the demand forecast can be found in Appendix F, Demand Forecasting Models.

Figures 6-30 and 6-31 show the resulting heating degree days and cooling degree days from the three temperatures scenarios presented to the stakeholders compared to the current 30-year normal weather approach.

Figure 6-30: Annual Heating Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast

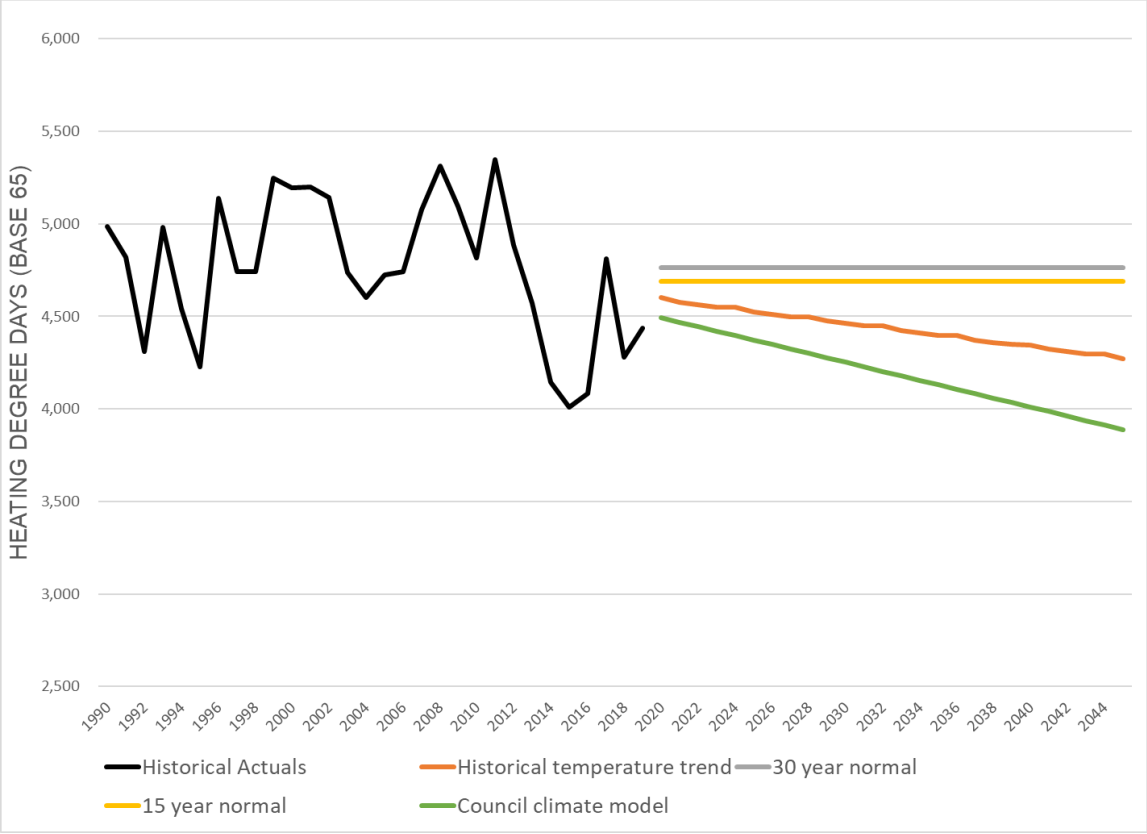
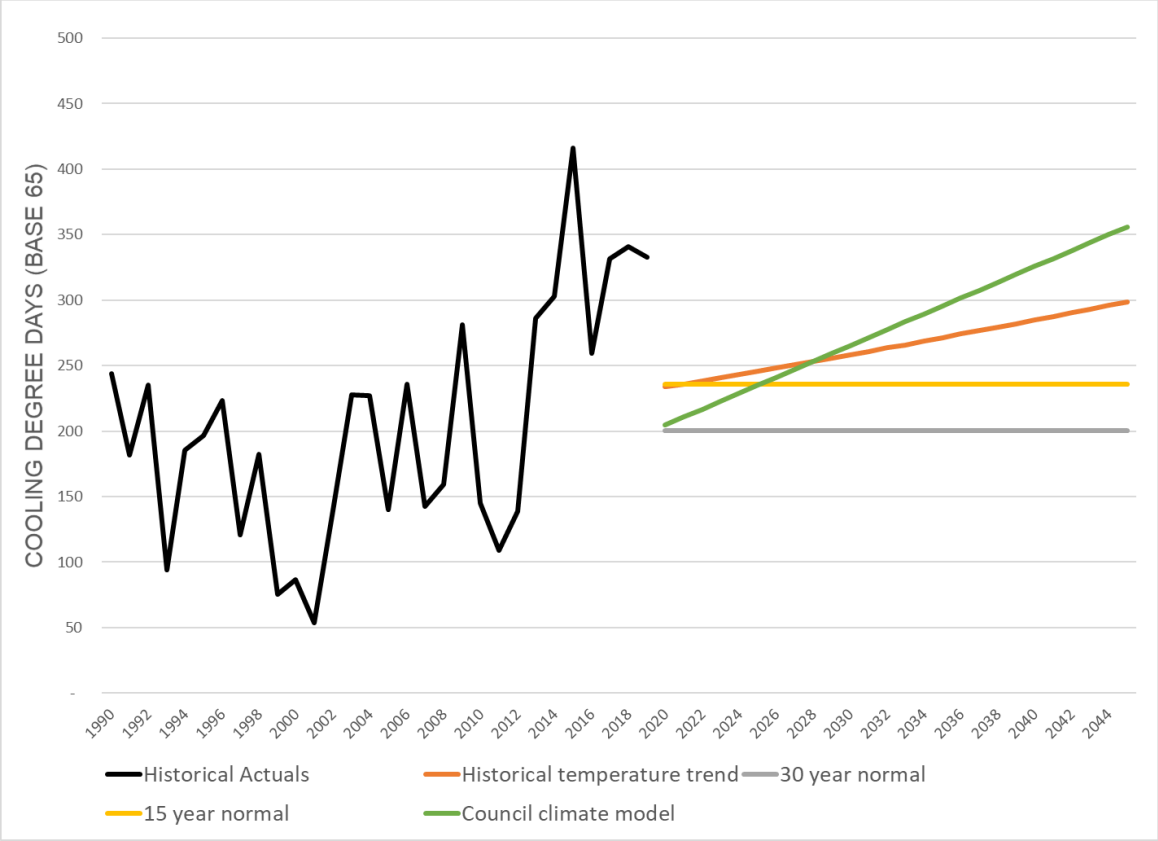


Figure 6-31: Annual Cooling Degree Days (Base 65) for the Three Temperature Sensitivity Options Compared to 30-year Normal HDDs Used in the Base Demand Forecast



Through the sensitivity prioritization process, stakeholders selected temperature sensitivity Option 3, which is based on the Northwest Power and Conservation Council climate model that assumes 0.9 degrees Fahrenheit warming per decade. Figures 6-32 and 6-33 compare the IRP base electric and natural gas energy demand forecasts with the forecasts that result from using this future temperature assumption.

With climate change, average temperatures are increasing over time. However, extreme weather events, both hot and cold, may still occur. Therefore, PSE did not change the peak temperature assumptions for this analysis, and therefore the peak demand did not change with this analysis.

In addition to the electric and gas energy demand forecasts, the electric RA model was run for this temperature sensitivity. The RA model examines a number of possible future conditions, including temperatures. The base RA model uses 88 historic temperature years: to create a wider range of possible future temperatures, PSE used all three of the NWPCC models, which mirrors the range of temperatures in NWPCC's RA analysis.

To create the RA model inputs temperatures from all three NWPCC models were used (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA). Weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RA model run, while weather from 2030 to 2039 was used for the 2031 to 2032 RA model run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model.

Figure 6-32: Base Electric Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast (aMW)

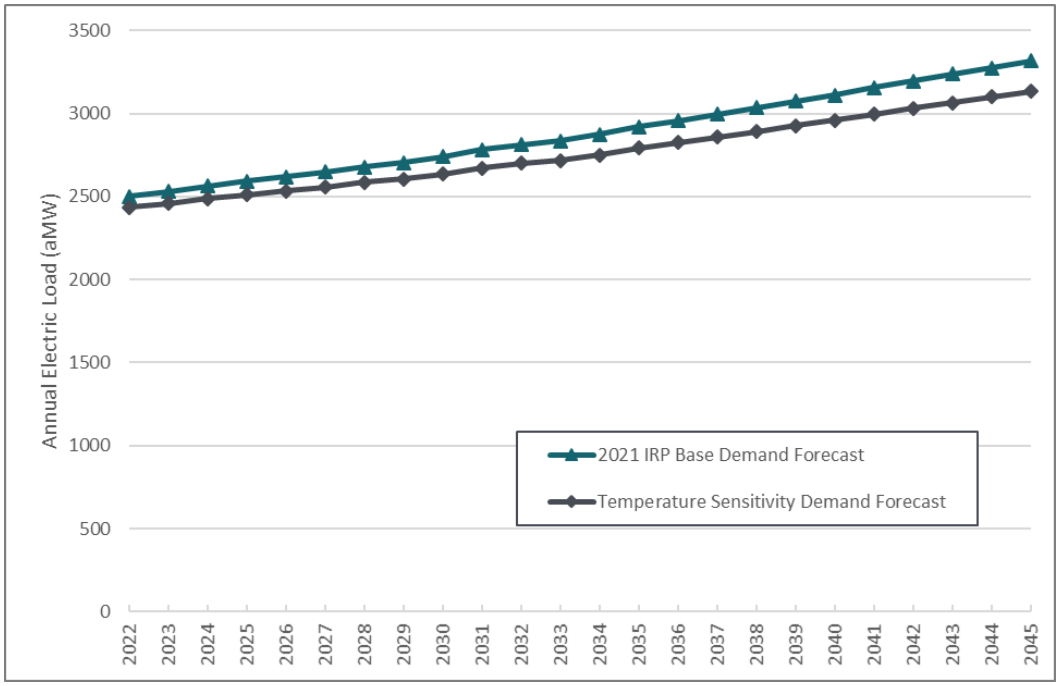
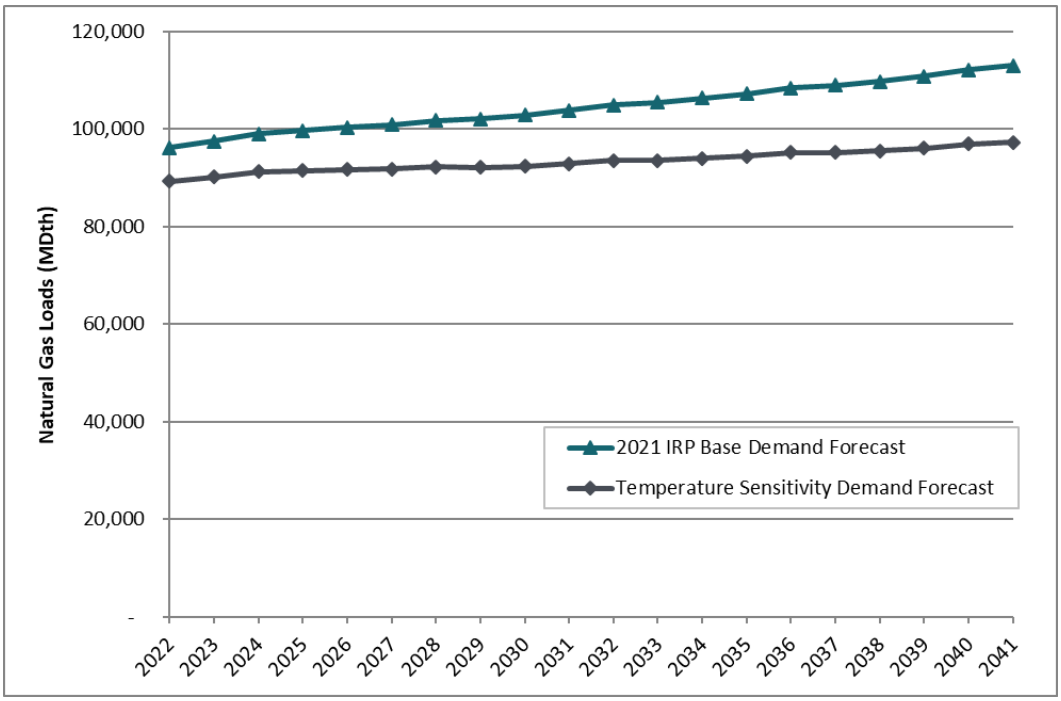


Figure 6-33: Base Natural Gas Energy Demand Forecast before Additional DSR Compared to Temperature Sensitivity Demand Forecast, without Transport Load (MDth)



Updates to Inputs and Equations

Updates to the demand forecast inputs and equations made since the 2019 IRP Process are summarized below.

POPULATION FORECAST. In previous IRPs, PSE has used Moody's forecast of U.S. population along with the economic and demographic model to forecast population in the electric and natural gas service areas. This has been under-forecasting population growth in the Puget Sound Area. In the 2021 IRP, population forecast is built up from county population forecasts that the Washington Employment Security Department (WA ESD) publishes. This better aligns the electric and natural gas forecasts of residential customers with population growth. Therefore, as population growth slows in the later part of the forecast period, the residential customer counts also slow.

ELECTRIC COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES. To better model the different segments of the electric commercial and industrial classes, the classes were broken out into smaller segments, including small/medium, large, high voltage and commercial lighting. Customer counts and use per customer were modeled for each segment individually, then added up to create the total customer counts and energy demand for each class.

SUMMER PEAK MODELING. The electric peak model was updated to include an index of air conditioning (AC) saturation in lieu of a linear trend as a proxy of past and future AC adoption. The AC index is created by using PSE's historical Residential Characteristics Survey (RCS) data points and calibrating to the U.S. Energy Information Administration (EIA) trend (West Region). The model driver was adopted to better track the non-linear nature of historical and future AC adoption.

MODELING SOFTWARE UPDATE. PSE transferred the demand forecast model from the Eviews application to energy forecasting software developed by Itron. The transition to Itron software enables PSE to manage the forecast input and output data in a database format (rather than separate Excel spreadsheets) and is modular in nature, organizing the forecasting steps in a consistent fashion across models. The modeling approach and methodology has not materially changed with this transition.

5. KEY ASSUMPTIONS

To develop PSE's demand forecasts, assumptions must be made about economic growth, energy prices, weather and loss factors, including certain system-specific conditions. These and other assumptions are described below.

Economic Growth

Economic activity has a significant effect on long-term energy demand. While the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating/cooling, water heating, lighting, cooking, dishwashing/clothes washing, electric vehicles and various other electric plug loads. The growth in residential building stock therefore directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting and for various plug loads. Energy is also an important input into many industrial production processes. Economic activities in the commercial and industrial sectors are therefore important indicators for the overall trends in energy consumption.

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, the IRP forecast begins with assumptions about what is happening in the broader U.S. economy. PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. The May 2020 Moody's forecast was used for this IRP.

The Moody's forecast calls for:

- A drop in employment and a sharp rise in unemployment in the second quarter of 2020 due to the COVID-19 pandemic. Unemployment stays above 6 percent until the first quarter of 2022, and is above 5 percent until the first quarter of 2023.
- After 2023 Moody's predicts the economy grows modestly as the U.S. population growth rate slows in the long term.
- U.S. GDP to continue to grow over the forecast period with 2.2 percent average annual growth from 2022 to 2045. This growth rate is higher compared to the Moody's forecast used in the 2019 IRP Process, which projected 2.0 percent average annual growth, but some of this growth is from the projected recovery from COVID-19.

- Average annual population growth of 0.4 percent for 2022-2045. This is down from the 0.6 percent growth rate Moody's forecast in the 2019 IRP Process for 2020-2039. However, this IRP did not use Moody's population projections because PSE's regional projections based on Moody's U.S. forecasts were consistently under-forecasting population growth in the electric and natural gas service areas. Instead, PSE used the Washington State Employment Security Department (WA ESD) population projections by county for the electric and natural gas service areas.

Moody's identified possible risks that could affect the accuracy of this forecast:[5]

- The Moody's forecast assumes that COVID-19 infections peak in May 2020 and begin to abate in July 2020. There is a downside risk if additional outbreaks occur, which are possible until a vaccine is widely available.
- Re-imposition of social distancing and forced business closures could derail any recovery that the economy has made.
- Moody's assumes that government and lawmakers provide monetary and fiscal responses to the pandemic to stabilize financial markets. The timing and size of this response is critical for determining the shape of the recovery.
- Changes to the economies of other global powers could affect the U.S. economy, especially as the demand for goods and services changes with the pandemic.
- Retaliations to U.S. tariffs could cause lower U.S. and global growth.

Regional Economic Outlook

PSE prepares regional economic and demographic forecasts using econometric models based on historical economic data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

PSE's service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. PSE serves more than 1.1 million electric customers and more than 840,000 natural gas customers in 10 counties.

Within PSE's service area, demand growth is uneven. Most of the economic growth is driven by growth in the high tech, information technology or retail (including online retail) sectors; supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for half or more of the system's electric and

5 / Moody's Analytics (2020, May) Forecast Risks. Precis U.S. Macro. Volume 25 Number 2.

natural gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

Electric Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2021 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate of 0.6 percent between 2022 and 2045, which is the same as the annual growth rate forecasted in the 2019 IRP Process.
- Local employers are expected to create about 310,000 total jobs between 2022 and 2045, mainly driven by growth in the commercial sector, compared to about 257,000 jobs forecasted in the 2019 IRP Process.
- Manufacturing employment is expected to decline by 0.1 percent annually on average between 2022 and 2045 due to the outsourcing of manufacturing processes to lower wage or less expensive states or countries, and due to the continuing trend of capital investments that create productivity increases.
- An inflow of 975,000 new residents (by birth or migration) is expected to increase the local area population to 5.3 million by 2045, for an average annual growth rate of 0.9 percent. This growth rate is not constant over time, and the population growth rate is expected to be higher in the near term and lower in the long term. However, on average, this growth rate is higher than the 2019 IRP Process forecast, which projected an average annual population growth of 0.6 percent that would have resulted in 4.6 million electric service area residents by 2039. The 2021 forecast has a different growth rate because the population forecast in this IRP is based on the WA ESD forecast of population instead of Moody's population forecast.

Local economists at Western Washington University have identified possible risks to the regional economy:[6, 5]

- It is unknown when the COVID-19 vaccine will achieve widespread immunity.
- Employers are taking on debt to make ends meet as their customers are spending less.
- Unforeseen layoffs from struggling businesses could slow economic recovery.
- Political and social unrest will have unknown effects on the economy.
- Lingering U.S.-China tension could affect the economy.

HIGH SCENARIO OUTLOOK. For the Electric High Demand Forecast scenario, population grows by 1.1 percent annually from 2022 to 2045, and employment grows by 0.8 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Electric Low Demand Forecast scenario, population grows by 0.7 percent annually from 2022 to 2045. Employment grows 0.3 percent annually from 2022 to 2045.

The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 6-34 and 6-35.

5 / Western Washington University Center of Economic and Business Research (2020, June) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 2.

6 / Western Washington University Center of Economic and Business Research (2020, March) Regional Outlook. Puget Sound Economic Forecaster. Volume 28 Issue 1.

Figure 6-34: Population Growth, Electric Service Counties

2021 IRP POPULATION GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	4,334	4,482	4,715	4,936	5,134	5,310	0.9%
2021 IRP High Demand Forecast	4,398	4,609	4,902	5,158	5,398	5,609	1.1%
2021 IRP Low Demand Forecast	4,267	4,363	4,536	4,723	4,869	4,989	0.7%

Figure 6-35: Employment Growth, Electric Service Counties

2021 IRP EMPLOYMENT GROWTH, ELECTRIC SERVICE COUNTIES (1,000s)							
Scenario	2022	2025	2030	2035	2040	2045	AARG 2022-2045
2021 IRP Base Demand Forecast	2,172	2,268	2,327	2,385	2,436	2,482	0.6%
2021 IRP High Demand Forecast	2,365	2,488	2,562	2,669	2,744	2,814	0.8%
2021 IRP Low Demand Forecast	1,996	2,047	2,088	2,103	2,145	2,159	0.3%

Natural Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Natural Gas Demand Forecast scenario, population grows by 1.0 percent annually from 4.5 million people in 2022 to 5.45 million people by 2041. Employment is expected to grow by 1.2 percent annually from 2022 to 2041.

HIGH SCENARIO OUTLOOK. For the High Natural Gas Demand Forecast scenario, population grows by 1.2 percent annually from 2022 to 2041, and employment grows by 2.1 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Natural Gas Demand Forecast scenario, population grows 0.8 percent annually from 2022 to 2041, and employment grows 0.2 percent annually.

The Base, High and Low population and employment forecasts for PSE's natural gas sales service area are compared in Figures 6-36 and 6-37.

Figure 6-36: Population Growth, Natural Gas Service Counties

2021 IRP POPULATION GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	4,542	4,703	4,953	5,197	5,452	1.0%
2021 IRP High Demand Forecast	4,619	4,842	5,159	5,437	5,766	1.2%
2021 IRP Low Demand Forecast	4,461	4,575	4,769	4,955	5,146	0.8%

Figure 6-37: Employment Growth, Natural Gas Service Counties

2021 IRP EMPLOYMENT GROWTH, NATURAL GAS SERVICE COUNTIES (1,000s)						
Scenario	**2022**	**2025**	**2030**	**2035**	**2041**	**AARG 2022-2041**
2021 IRP Base Demand Forecast	2,225	2,368	2,497	2,628	2,780	1.2%
2021 IRP High Demand Forecast	2,478	2,748	3,043	3,257	3,655	2.1%
2021 IRP Low Demand Forecast	1,975	1,987	1,989	2,022	2,042	0.2%

Other Assumptions

Weather

For the IRP Base Demand scenario, the energy demand forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2019. The 2021 IRP forecast methodology, as described in this chapter and Appendix F, Demand Forecasting Models, employs various thresholds of heating and cooling degree days, consistent with industry practices. Employing monthly degree days helps estimate the amount of weather-sensitive demand in the service area. PSE rolls forward the 30-year period employed in each IRP to capture recent climate conditions. To create the High and Low Demand Forecasts historic monthly temperature observations are used to project a distribution of possible future temperature-sensitive demand, thereby modeling a wider range of warmer and colder conditions than the Base Demand Forecast.

In this IRP, PSE is including a temperature sensitivity that explores how changing heating and cooling degree days could affect loads in the future as the climate warms. This sensitivity is described in detail in Chapter 5, Key Analytical Assumptions.

Additionally, PSE is following and participating in the regional efforts of the Northwest Power and Conservation Council to include climate change in its planning process. These efforts include both forecasting future temperatures as well as considering secondary effects of climate change on population and economic growth. Future IRPs will incorporate climate change impacts as regionally accepted information becomes available.

COVID-19 Adjustments

In early March 2020, the COVID-19 pandemic reached the Puget Sound region in earnest. The governor issued a "Stay Home, Stay Healthy" order on March 23 that had immediate impacts on the local economy. To account for the pandemic's effects on the economy, customer counts and demand, PSE incorporated the May 2020 Moody's Analytics economic forecast, the most current Moody's forecast at the time the IRP forecast was developed. Moody's forecast included the following economic and epidemiological assumptions about the severity of the disease and its effects on the economy: that new infections would abate in July 2020 without a second wave of infections; that unemployment would spike in 2Q 2020; and that the recovery from the resulting recession would last through 2023, when unemployment would return to around 5 percent.

The typical relationship between historic economic assumptions and the forecast was not able to capture all of the immediate impacts to the demand forecast for year 2020, so PSE made additional assumptions and adjustments to reflect the impacts of COVID-19 by tracking the observed effects on each customer class. For the commercial class, PSE assessed the potential

impacts by building type, since some sectors of the economy were hit harder than others. Adjustments from these additional analyses were then aligned with the epidemiological assumptions made by Moody's May 2020 forecast.

After 2020, no additional adjustments were made above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was a slow recovery over the following few years and a recovered economy by 2024, with lingering effects from the recession persisting thorough out the remainder of the forecast.

PSE performed stochastic simulations that varied the economic forecast around this base forecast. These included simulations with better and worse economic outcomes that were the basis for the high and low forecasts. Since the IRP determines the resource need starting in 2022, the high and low forecasts show alternative ways the pandemic could resolve in the future.

Loss Factors

The electric loss factor is 6.8 percent, compared to 7.1 percent in the 2019 IRP Process. The gas loss factor in this IRP is 0.2 percent, which is the same as the loss factor in the 2019 IRP Process. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past 2 to 3 years.

Block Load Additions

Beyond typical economic change, the demand forecast also takes into account known major demand additions and deletions that would not be accounted for though typical load growth in the forecast. The majority of these additions are from major infrastructure projects. These additions to the forecast are called block loads and they use information provided by PSE's system planners. The adjustments to non-transport customers add 91.1 MW of connected demand by 2025 for the electric system as a whole. These block loads are included in the commercial class, and King County has the majority of the additions.

The natural gas forecast includes block loads of 0.1 MDth per day which are included in the industrial class.

Schedule Switching

In addition to block loads, PSE accounts for customers that switch between rate schedules. Customers that purchase their own electricity or natural gas are called transportation customers and they rely on PSE for distribution services. Because PSE is not responsible for acquiring supply resources for electric or natural gas transportation customers, in the IRP they are removed from the forecast before supply-side resource need is determined.

Interruptible Loads

PSE has 152 electric interruptible customers; six of these are commercial and industrial customers and 146 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 14 MW of coincident peak demand. In this IRP, PSE did not count the 14 MW of DR potential, but this will be included in future modeling.

For a number of natural gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was assumed when forecasting peak natural gas demand.

Electric Vehicles

An electric vehicle (EV) forecast was created for PSE by Guidehouse in early 2020. The forecast assumes 60,000 customer-owned light duty EVs on the road in PSE's service area in 2022, increasing to 705,000 EVs in 2045. Annual energy sales from new electric vehicles total 83,000 MWh in 2022 and 1,960,000 MWh in 2045. Initially, 81 percent of this charging is assumed to occur on residential accounts, while the remaining 19 percent is assumed to occur through commercial accounts. During the forecast period this percentage changes as charging at commercial locations becomes more widely available, resulting in 56 percent charging on residential accounts and 44 percent charging on commercial accounts in 2045. Electric vehicles are an emerging technology, thus PSE anticipates this forecast will be revised on an ongoing basis in the future. The additional demand by electric vehicles grows to an 8 percent share of total peak demand by 2045, before including cost-effective DSR identified in the 2021 IRP. Figure 6-38 below shows the December evening peak demand and annual average energy demand from new electric vehicles. Figure 6-39 shows the forecast of electric vehicles as a percent of all vehicles purchased in the PSE service territory.

Figure 6-38: Electric Vehicle Peak Demand and Average Energy Demand from New Vehicles (aMW, MW)

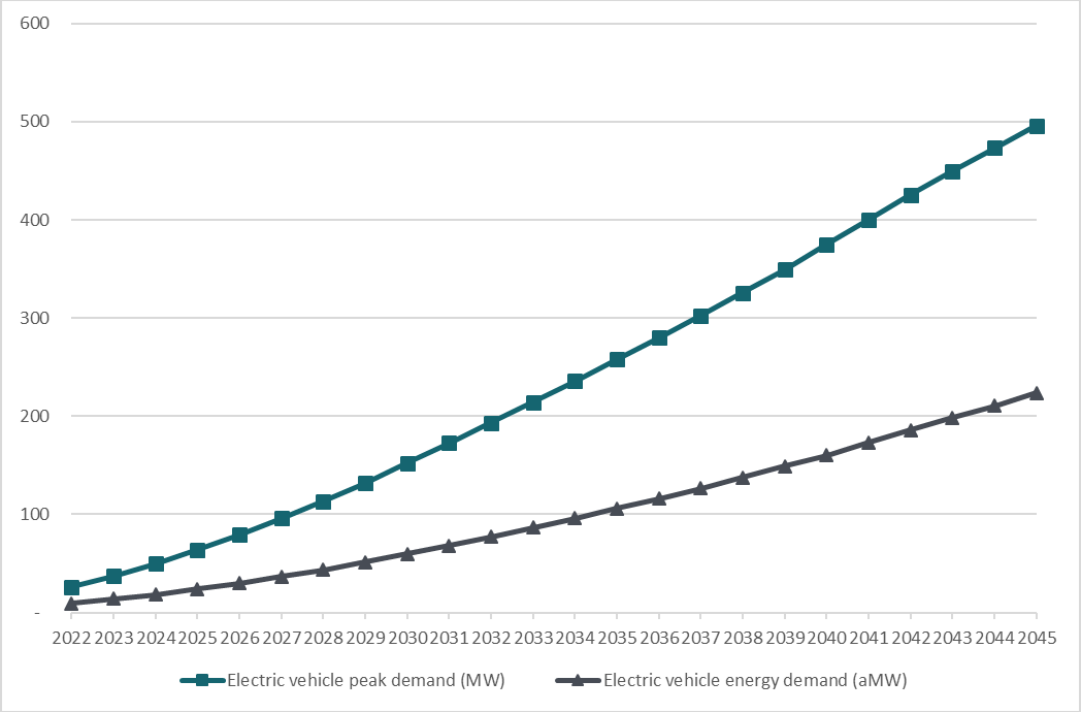
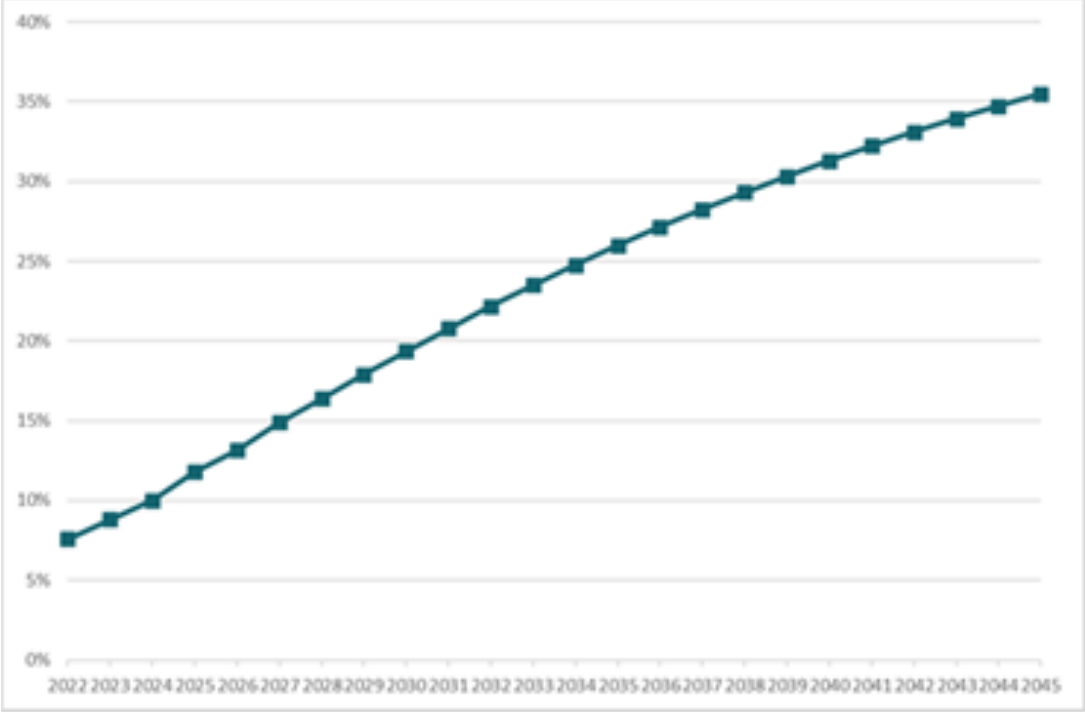


Figure 6-39: Electric Vehicles as a Percent of Purchased Vehicles



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2021 IRP Natural Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2022, this adds 365 MDth to the forecast. This demand is expected to grow at an average annual rate of 3.5 percent, based on the Annual Energy Outlook 2019 published by the U.S. Department of Energy.

Retail Rates

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models, because in the long run, they affect customer choices about the efficiency level of newly acquired appliances, how those appliances are used, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Distributed Generation

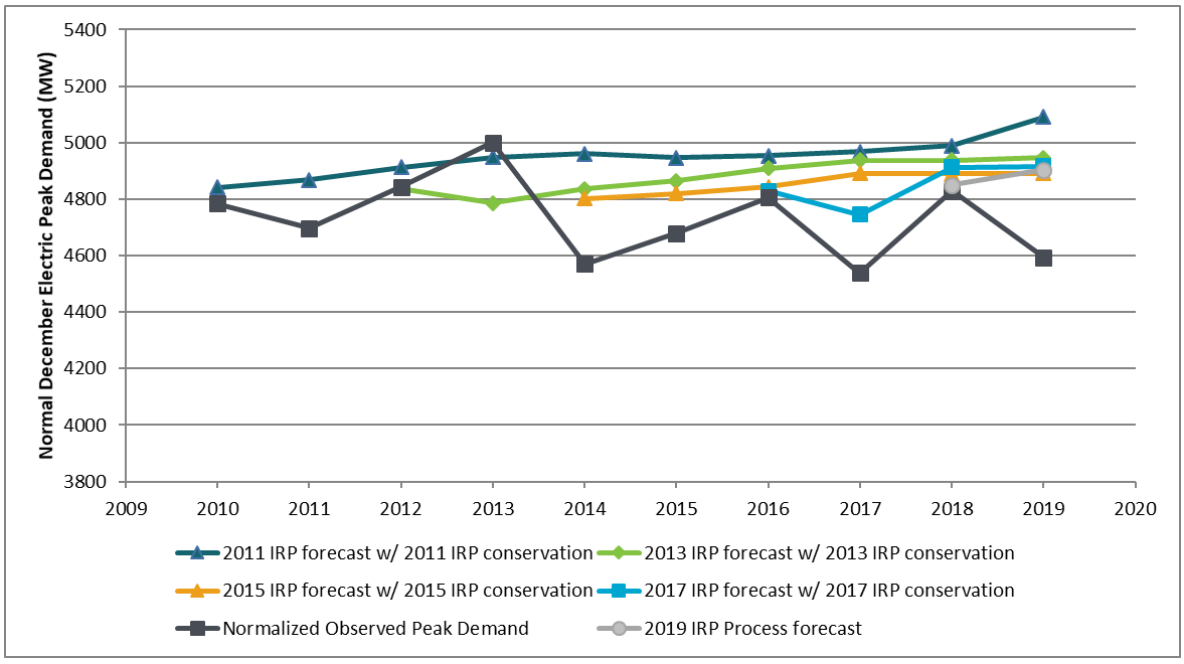
Distributed generation, including customer-level generation via solar panels, was not included in the demand forecast; this energy production is captured in the IRP modeling process as a demand-side resource. A description is included in the Appendix E, Conservation Potential Assessment and Demand Response Assessment.

6. RETROSPECTIVE OF PREVIOUS DEMAND FORECASTS

IRP Peak Demand Forecasts Compared to Actual Peaks

Figure 6-40 compares the 2011, 2013, 2015, 2017 and 2019 IRP Process electric Base Scenario peak demand forecasts after DSR with normalized[7] actual observations. The normalized actual observations account for peak hourly temperature, monthly HDDs, and the day of week and time of day the actual peak was observed. The percent difference of normalized actual values compared to each IRP forecast is presented for each year in Figure 6-41.

Figure 6-40: Observed Normalized Electric December Peak Demand Compared to Previous IRP forecasts



7 / Given that the forecasts are for peaks at a design temperature, observed actual peaks are adjusted to reflect what would have been the peak if the design peak temperatures had been achieved.

Figure 6-41: Observed Electric Peak Demand and Difference from Previous IRP Forecasts

ELECTRIC DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**	**2019 IRP Process**
2010	1.2%				
2011	3.6%				
2012	1.5%	-0.1%			
2013	-1.0%	-4.3%			
2014	8.5%	5.8%	5.1%		
2015	5.7%	4.0%	3.0%		
2016	3.1%	2.1%	0.8%	0.5%	
2017	9.5%	8.8%	7.8%	4.6%	
2018	3.3%	2.3%	1.2%	1.7%	0.5%
2019	10.8%	7.7%	6.5%	7.1%	6.8%

Similarly, weather normalized actual natural gas peak demand is compared to the natural gas peak forecasts after conservation from the 2011, 2013, 2015, 2017 IRPs and the 2019 IRP Process in Figures 6-42 and 6-43.

Figure 6-42: Observed Weather Normalized Natural Gas Peak Demand Compared to Previous IRP Forecasts of Natural Gas Peak Demand

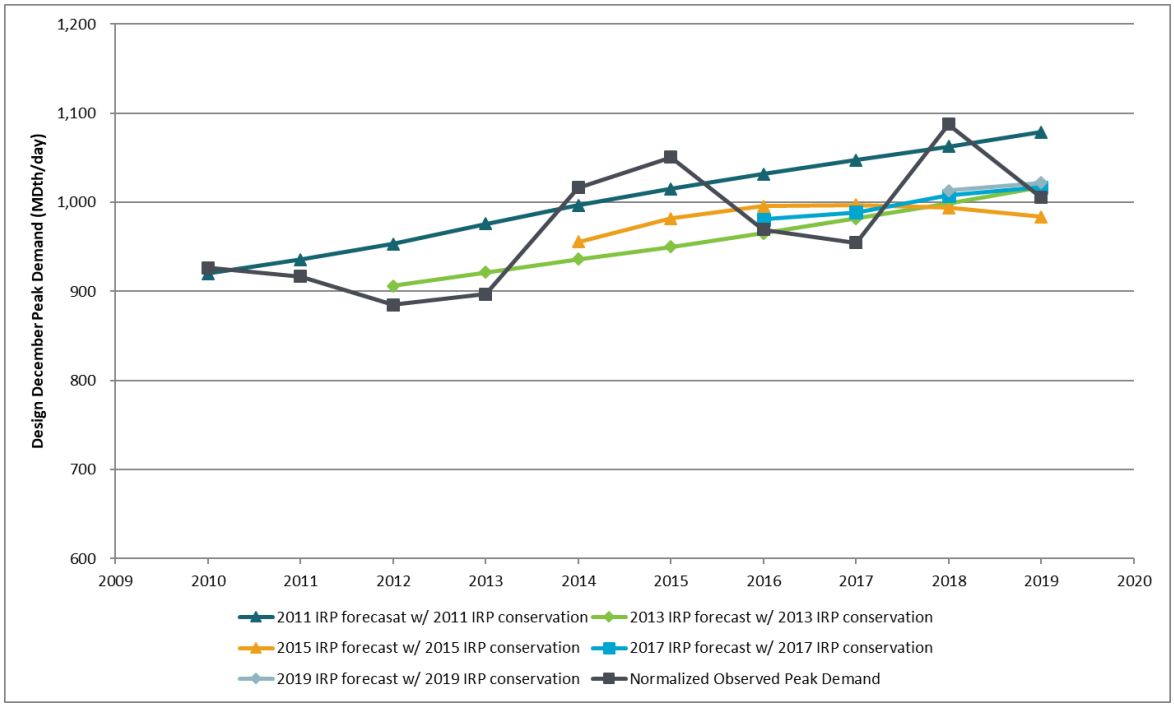


Figure 6-43: Observed Natural Gas Peak Demand and Difference from Previous IRP Forecasts

NATURAL GAS DECEMBER PEAK DEMAND % DIFFERENCE OF IRP FORECAST VERSUS WEATHER NORMALIZED ACTUAL OBSERVATION					
Year	**2011 IRP**	**2013 IRP**	**2015 IRP**	**2017 IRP**	**2019 IRP Process**
2010	-0.7%				
2011	2.0%				
2012	7.8%	2.4%			
2013	8.8%	2.7%			
2014	-2.0%	-7.9%	-5.6%		
2015	-3.4%	-9.6%	-6.1%		
2016	6.4%	-0.4%	3.2%	1.2%	
2017	9.7%	2.8%	5.0%	3.6%	
2018	-2.3%	-8.2%	-8.2%	-7.4%	-6.9%
2019	7.3%	1.1%	-1.7%	1.1%	1.6%

Reasons for Forecast Variance

As explained throughout this chapter, the IRP peak demand forecasts are based on forecasts of key demand drivers that include expected economic and demographic behavior, conservation, customer usage and weather. When these forecasts diverge from observed actual behavior, so does the IRP forecast. These differences are explained below.

Economic and Demographic Forecasts

Economic and demographic factors are key drivers for the IRP peak demand forecast. After the 2008 recession hit the U.S. economy, many economists, including Moody's Analytics, assumed that the economy would recover sooner than it did. A full recovery was pushed out with each successive forecast as the U.S. economy failed to bounce back to its previous state year after year. The charts below compare the Moody's forecasts of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP Process with actual U.S. housing starts and population growth. Moody's too-optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP Process, forecasts of housing starts are no longer used as a driver in the demand forecast; instead, forecasts of population based on WA ESD data are now used to forecast population in PSE's service territories. The Moody's forecast of housing starts and population from May 2020 are included in the two charts below for comparison

Additionally, while the Moody's forecast used in the 2019 IRP Process did predict a softening of the economy in 2020, it did not forecast the magnitude of the effects from the COVID-19 pandemic. Therefore, Moody's forecasts used prior to the 2021 IRP have likely over-estimated economic growth in 2020 and the following few years. It is likely that the full extent of the pandemic's repercussions on the economy and energy demand will not be known during this IRP cycle.

Figure 6-44: Moody's Forecasts of U.S. Housing Starts Compared to Actual Housing Starts

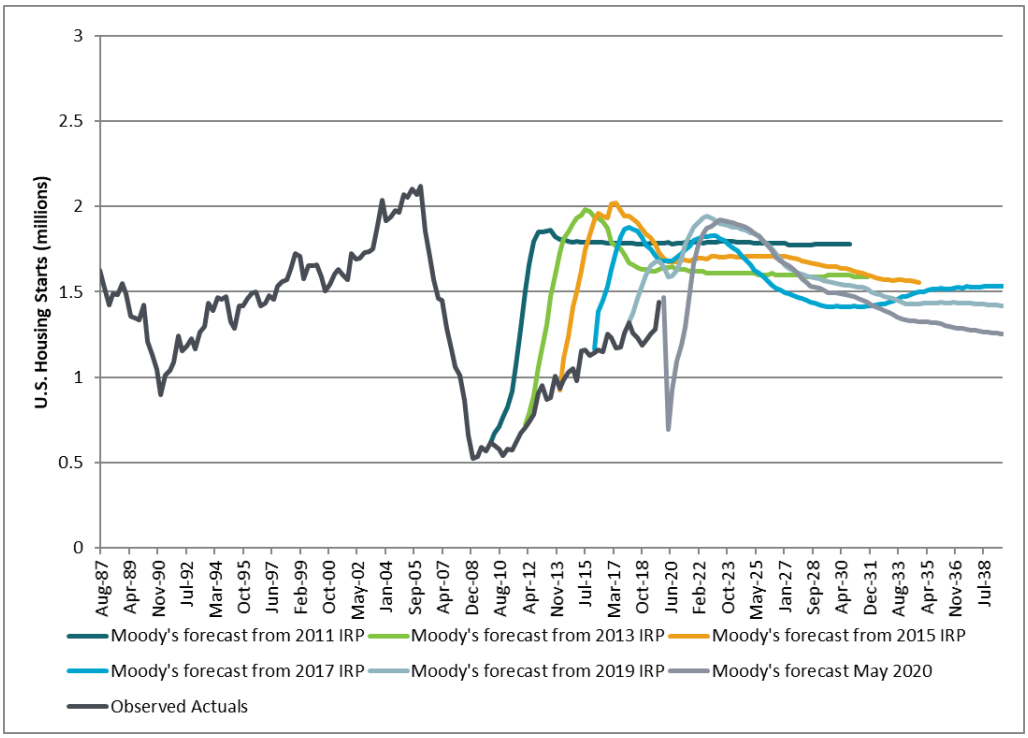
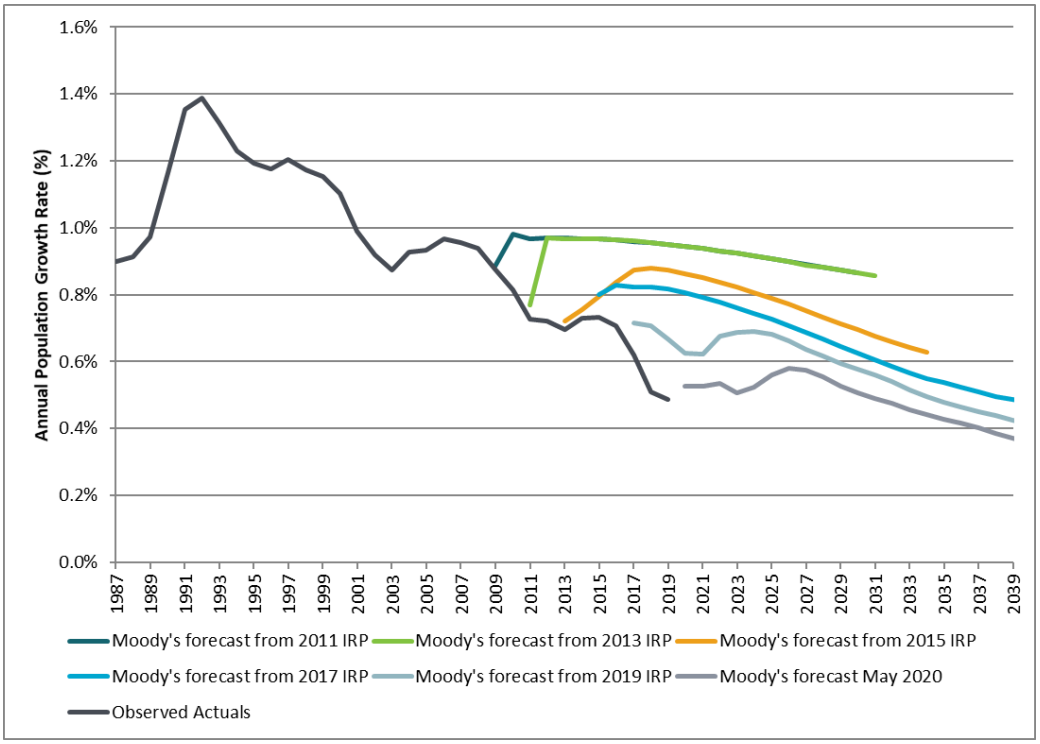


Figure 6-45: Moody's Forecasts of U.S. Population Growth Compared to Actual Population Growth



Conservation and Customer Usage

The comparison in Figures 6-40 and 6-42 of weather normalized peak observations to the IRP peak demand forecasts after conservation assumes that the forecasted conservation will be implemented. However, consumers can adopt energy efficient technologies that are above and beyond what is incentivized by utility-sponsored conservation programs and building codes and standards. This leads to more actual conservation taking place than forecasted. Additionally, conservation programs can change over time. Programs that were not cost effective in the past, and therefore not included in the optimal bundle, can be chosen in a later IRP as cost effective. This can make an older forecast out of date, making the forecast of conservation too low and therefore the load forecast after conservation too high.

Also, due to the Global Settlement from the 2013 General Rate Case (GRC) PSE and the 2017 GRC, PSE decisions accelerate electric and natural gas conservation, respectively, by 5 percent each year. This is additional conservation that is not taken into account in this comparison of IRP forecasts with normalized actuals.

Normal Weather Changes

Normal weather assumptions change from forecast to forecast. For each IRP, the normal weather assumption is updated by rolling off two older years of data and incorporating two new years of weather data into the 30-year average. Over time, normal heating degree days have been declining and normal cooling degree days have been increasing. As temperatures change over time, the forecast of demand with normal weather changes.

Additionally, over time our customers' weather sensitivity has been changing. As energy efficiency measures have been implemented, customers use less energy at a given temperature, including at peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

Non-design Conditions during Observed Peaks

Peak values are weather normalized using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand and peak temperature. However, some of the observed December peaks shown above occurred on atypical days rather than typical days. For example, natural gas peaks in 2010, 2013, 2016, and 2017 fell on weekends. Natural gas peaks in 2010, 2012, and 2015 fell on New Year's Eve and the 2019 peak fell on Boxing Day (the day after Christmas). Additionally, in 2014, the electric peak fell on the Monday morning after Thanksgiving weekend, in 2015 it fell on New Year's Eve, and in 2019 it fell on the day after Christmas. Usage on these days is likely to be different than usage on a typical non-holiday weekday peak. Therefore, when these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

Service Area Changes

In March 2013, Jefferson County left the PSE service area. Jefferson County usage was included in the electric peak demand forecast in the 2011 IRP, therefore, when comparing that forecast to today's actuals, those forecasts would be expected to be higher than the actual peak demand.



7 Resource Adequacy Analysis

This appendix provides an overview of PSE's resource adequacy modeling framework and how it aligns with other regional resource adequacy analyses.

7 Resource Adequacy Analysis

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1. OVERVIEW

The energy supply industry is in a state of transition as major decarbonization policies are implemented in most states. Significant amounts of coal-fired generation is being retired, and new intermittent, renewable generation is being constructed. These changes will cause PSE and other utilities to significantly change how they plan, especially with regard to resource adequacy. To maintain confidence in the wholesale market and ensure that sufficient resources are installed and committed, PSE, along with Northwest Power Pool members, is designing and implementing a regional resource adequacy program. The detailed design phase of the resource adequacy program is under way, with completion expected in mid-2021. As more details are understood, PSE will begin the evaluation of various resource adequacy elements in the resource adequacy analysis included in the 2021 IRP. At this time, the regional resource adequacy program has not been contemplated or included in the analysis described in this chapter.

In the past, relying on short-term wholesale energy markets has been a very cost-effective strategy for customers. This strategy also avoided building significant amounts of new baseload natural gas generation that might have created significant stranded cost concerns under the new policies. Recent experience shows that while wholesale electricity prices remain low, on average, in the Pacific Northwest (PNW), the region is starting to experience periods of high wholesale electricity prices and low short-term market liquidity.

In addition to the resource adequacy analysis, PSE has a completed a market risk assessment which evaluates the availability of short-term market purchases for peak capacity. It is important that PSE continue to closely monitor the region's projected winter and summer season load/resource balance and any changes in the liquidity of the short-term market, and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

2. 2021 IRP RESOURCE ADEQUACY ANALYSIS

Resource adequacy planning is used to ensure that all of PSE customer's load obligations are reliably met by building sufficient generating capacity, or acquiring sufficient capacity through contracts, to be able to meet customer demand with appropriate planning margins and operating reserves. The planning margin and operating reserves refer to capacity above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events with minimal interruption of service. Unexpected events can be variations in temperature, hydro and wind generation, equipment failure, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Reliability requires that the full range of potential demand conditions are met even if the potential of experiencing those conditions is relatively low.

The physical characteristics of the electric grid are very complex, so for planning purposes, a 5 percent loss of load probability (LOLP) reliability metric is used to assess the physical resource adequacy risk. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulations. Therefore, the likelihood of capacity being lower than load at any time in the year cannot exceed 5 percent. The 5 percent LOLP is consistent with the resource adequacy metric used by the Northwest Power and Conservation Council (NPCC).

Quantifying the peak capacity contribution of a renewable and energy limited resource (its effective load carrying capacity or ELCC) is an important part of the analysis. The ELCC of a resource represents the peak capacity credit assigned to that resource. It is calculated in the resource adequacy model since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

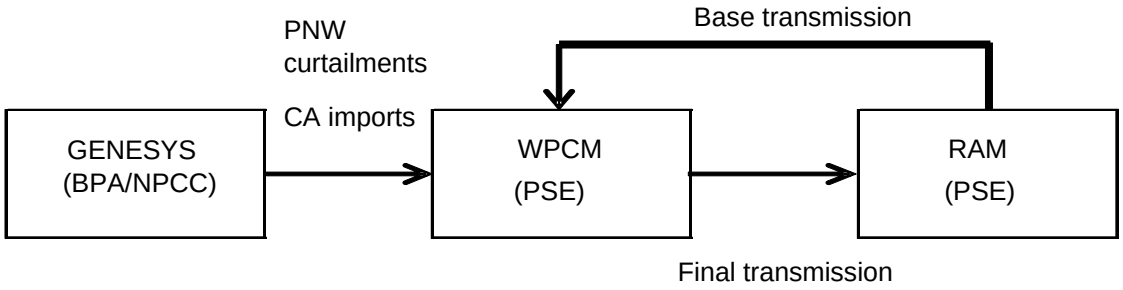
Resource Adequacy Modeling Approach

PSE's Resource Adequacy Model (RAM) is used to analyze load/resource conditions for PSE's power system. Since PSE relies on significant amounts of wholesale power purchases to meet peak need, the analysis must include evaluation of potential curtailments to regional power supplies. To accomplish this, the RAM integrates two other analyses into its results: 1) the GENESYS model developed by the NPCC and BPA, which analyzes regional level load/resource

conditions, and 2) the Wholesale Purchase Curtailment Model (WPCM), developed by PSE, which analyzes the specific effects of regional curtailments on PSE's system. This allows us to evaluate PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

Figure 7-1 illustrates how the inputs and outputs of these models were linked. The outputs of the GENESYS Model provide inputs for both the WPCM model and the RAM/LOLP model. The RAM/LOLP model and WPCM models are used iteratively, with the final output of the RAM/LOLP model used in the next WPCM modelling run.

Figure 7-1: Market Reliability Analysis Modeling Tools



The GENESYS Model

The GENESYS model was developed by the NPCC and the Bonneville Power Administration (BPA) to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions, and as of the 2023 assessment, 88 years of temperature conditions. For the 2021 IRP, PSE started with the GENESYS model from the NPCC power supply adequacy assessment for 2023. When combined with thermal plant forced outages, the mean expected time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW's overall hourly capacity surplus or deficit in 7,040 multi-scenario "simulations." Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to meet PNW firm loads regardless of cost, a regional load-curtailment event will occur on any hour that has a capacity deficit.[1]

1 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the 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, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits of 3,400 MW) utilizing both forward and short-term purchases.

Since the GENESYS model was set for a 2023 assessment, PSE made some updates to capture regional load/resource changes in order to run the model for the years 2027 and 2031. The updates that PSE made to the GENESYS model include:

1. Updated coal plant retirements with retirement years listed in Figure 7-2.

Figure 7-2: Coal Plant Retirements Modeled

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

2. Increased the year 2023 demand forecast using the escalation rate of 0.3 percent to the year 2027 and 2031. The escalation rate is from the NPCC demand growth after conservation.
3. Added planned resources from PSE's portfolio: Skookumchuck Wind (131 MW) and Lund Hill solar (150 MW).

PSE did not include any other adjustments to GENESYS for regional build and retirements, other than the updates described above, relying on the assumptions from NPCC already built into the model.

The Wholesale Purchase Curtailment Model (WPCM)

During a PNW-wide load-curtailment event, there is not enough physical power supply available in the region (including available imports from California) for the utilities of the region to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, PSE developed the WPCM as part of the 2015 IRP. The WPCM links regional events to their specific impacts on PSE's system and on PSE's 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 has a direct impact on the amount of capacity that PSE would be able to purchase. Therefore, the WPCM first assembles load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events. For this analysis, PSE used the capacity data contained in BPA's *2018 Pacific Northwest Loads and Resources Study*, the latest BPA study available at the time this resource adequacy analysis was completed. Due to the pandemic, BPA's 2019 study was delayed and not available for this analysis.

BPA Loads and Resources Study for 2020–2029

BPA published its *2018 Pacific Northwest Loads and Resources Study* in April 2019. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region.

The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads.

- For 2023, the BPA study forecasts an overall regional winter peak load deficiency of 3,056 MW.
- When BPA's 2023 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 3,056 MW capacity deficit noted above would change to a 344 MW surplus.
- Looking forward to 2029 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2020 winter season peak load deficit of approximately 246 MW to a peak load deficit of approximately 4,891 MW in 2029.
- When BPA's 2029 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in its RAM – the region would transition from a 2020 winter capacity surplus of 3,054 MW to a peak load deficit of approximately 1,491 MW by 2029.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2023. The BPA forecast indicates, as does the Pacific Northwest Utilities Conference Committee (PNUCC) study, that the PNW may experience larger winter capacity deficits over time.

> > > BPA's *2018 Pacific Northwest Loads and Resources Study* can be found at: https://www.bpa.gov/p/Generation/White-Book/wb/2018-WBK-Loads-and-Resources-Summary-20190403.pdf

In October 2020, BPA published its *2019 Pacific Northwest Loads and Resources Study*. The study was completed after PSE finalized this resource adequacy analysis, so updated 2019 information could not be incorporated. PSE is reviewing the 2019 BPA study to assess its implications for the analysis.

Allocation Methodology

The WPCM then uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases. In essence, on an hourly basis, the WPCM portion of the resource adequacy analysis translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases. In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the LOLP portion of RAM.

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailment events.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.

SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed 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 (which is usually PSE)

would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually 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.

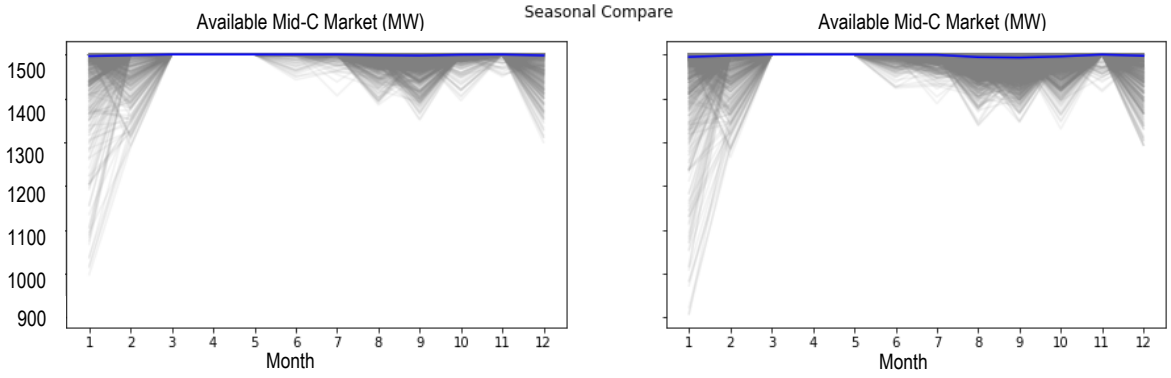
WPCM Outputs

For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-Columbia (Mid-C) transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.

Figure 7-3 shows the results of the WPCM. The charts illustrate the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 7-3: Reduction to Available Mid-C Market



In addition to the WPCM results that are included in PSE's resource adequacy analysis, PSE also conducted a separate market risk assessment. That assessment is described later in this chapter.

The Resource Adequacy Model (RAM)

PSE's probabilistic Resource Adequacy Model enables PSE to assess the following.

1. To quantify physical supply risks as PSE's portfolio of loads and resources evolves over time
2. To establish peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin
3. To quantify the peak capacity contribution of a renewable and energy-limited resource (its effective load carrying capacity, or ELCC)

The RAM allows for the calculation of the following risk metrics.

- **Loss of load probability (LOLP)**, which measures the *likelihood of a load curtailment event occurring* in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s).
- **Expected unserved energy (EUE)**, which measures outage magnitude in MWh and is the *sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations.*
- **Loss of load hours (LOLH)**, which measures outage duration and is *the sum of the hours with load curtailments divided by the number of simulations*.
- **Loss of load expectation (LOLE)**, which measures the *average number of days per year with loss of load* due to system load exceeding available generating capacity.
- **Loss of load events (LOLEV)**, which measures the *average number of loss of load events per year*, of any duration or magnitude, due to system load exceeding available generating capacity.

Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these five risk metrics, once a planning standard has been established.

3. CONSISTENCY WITH REGIONAL RESOURCE ADEQUACY ASSESSMENTS

PSE's reliance on market purchases requires that our resource adequacy modeling also reflect regional adequacy conditions, so consistency with the NPCC's regional GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM.

PSE's RAM operates much like the GENESYS model. Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 7,040 individual simulations; the result of each simulation is PSE's hourly capacity surplus or deficiency. The LOLP, EUE and LOLH for the PSE system are then computed across the 7,040 simulations.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 7,040 simulations made in the NPCC's GENESYS model in terms of temperature and hydro conditions.

The existing resources used by PSE included in this analysis are Mid-Columbia purchase contracts and western Washington hydroelectric resources, several natural gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. Since Colstrip must be out of PSE's portfolio by 2026, it was assumed to retire on 12/31/2025 and was not included as a resource in either GENESYS or RAM.

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

1. **FORCED OUTAGE RATE FOR THERMAL UNITS**. Forced outage refers to a generator failure event, including the time required to complete the repair. The "Frequency Duration" outage method in AURORA is used to model unplanned outages (forced outage) for thermal plants. The Frequency Duration outage method 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 method will employ all or nothing outages for most outages but will use partial outages at the beginning and end of the outage period. The logic considers each unit's forced outage rate and mean repair time. When the unit has a planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not included in the forced outage rate.

2. **HOURLY SYSTEM LOADS**. Hourly system loads are modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 88 temperature years. These demand draws are created with stochastic outputs from PSE's economic and demographic model and two consecutive historic weather years to predict future weather. Each historic weather year from 1929 to 2016 is represented in the 88 demand draws. Since the resource adequacy model examines a hydro year from October through September, drawing two consecutive years preserves the characteristics of each historic heating season. Additionally, the model examines adequacy in each hour of a given future year; therefore, the model inputs are scaled to hourly demand using the hourly demand model.

3. **MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 7,040 combinations of hydro and temperature simulations are consistent with the GENESYS model.

4. **WHOLESALE MARKET PURCHASES.** These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained above. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM. The initial set of hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights is computed 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 plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports was reduced on the hours when a PNW load-curtailment event is identified in the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

5. **WIND AND SOLAR.** PSE models 250 unique 8,760 hourly profiles, which exhibit the typical wind 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 this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind and solar generation are reflected. Wind speed data was obtained from the National Renewable Energy Laboratory's (NREL's) Wind Tool Kit database.[2] Wind speed data was collected from numerous sites within a prescribed radius around a region of interest. Wind speed data was processed with a heuristic wind production model to generate hundreds of possible generation profiles. The 250 profiles which aligned most closely with the average seasonal production of the site, as determined by the average of the entire data set, were selected for use in the RAM. The profiles were then correlated by measurement year. Similarly, solar irradiance data for a given region was obtained from the National Solar Radiation Database[3] and processed with the NREL System Advisory Model to generate production profiles. The 250 solar profiles which were most closely aligned with the annual average production, as determined by the annual average of the entire data set, were selected for use in the RAM. The solar profiles were correlated by measurement year.

Construction risk is not directly incorporated in the resource adequacy model. Permitting and construction times are accounted for in the first year that a new resource is available. For example, if a resource takes four years for permitting and construction, and the IRP planning horizon starts in 2022, the new resource would be available in the year 2026. A full discussion of construction and permitting lead times is available in Appendix D.

2 / https://www.nrel.gov/grid/wind-toolkit.html
3 / https://nsrdb.nrel.gov/

4. OPERATING RESERVES AND PLANNING MARGIN

Operating Reserves

North American Electric Reliability Council (NERC) standards require that utilities maintain "capacity reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool (NWPP), therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves.

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA).

In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60 minutes, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power or curtailing load. The RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, should a forced outage at one of PSE's generating plants cause loads to exceed available resources.

BALANCING AND REGULATING RESERVES. 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 kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves are resources that have the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.

The balancing reserve requirements were assessed by E3 for two study years, using the CAISO flex ramp test. The results depend heavily on the Mean Average Percent Error (MAPE) of the hour-ahead forecasts versus real-time values for load, wind and solar generation. The first study was for the year 2025 and includes PSE's current portfolio plus new renewable resources. The second study is for the year 2030 and includes PSE's current portfolio plus generic wind and solar resources to meet the 80 percent renewable requirement. Figure 7-4 below is a summary of the flex up and flex down requirement given the renewable resources that PSE will balance. By 2030, PSE's balancing reserve requirements will significantly increase with the large increase in intermittent renewable resources. The increase in balancing reserves will increase the need for flexible capacity resources. This analysis was based on the results from the 2019 IRP Process, where PSE estimated that it will balance almost 2,400 MW of wind and 1,400 MW of solar by 2030 to meet CETA goals. These results are in alignment with the 2021 IRP process.

Figure 7-4: Balancing Reserve Requirements

Case	Capacity of PSE-balanced Wind (MW)	Capacity of PSE-balanced solar (MW)	Average Annual Flex up (MW)	Average Annual Flex down (MW)	99th percentile of forecast error (flex up cap)	1st percentile of forecast error (flex down cap)
2025 Case	875	-	141	146	190	196
2030 Case	2,375	1,400	492	503	695	749

This table is a summary of the flexible ramp requirements. RAM uses for the hourly flex up and flex down requirements for each study year.

Planning Margin

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin is defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of reliable service to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

> Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics such as the likelihood (i.e., LOLP), magnitude (i.e., EUE) and duration (i.e., LOLH) of supply-driven customer outages. Those metrics can then be used to quantify the relative capacity contributions of different resource types towards meeting PSE's firm peak loads. These include thermal resources, variable-energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

In this IRP, PSE continues to utilize the LOLP metric to determine its capacity planning margin and establishes the 5 percent LOLP level used by the NPCC as adequate for the region. This value is obtained by running the 7,040 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using "perfect" capacity, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

5. 2021 IRP RAM INPUT UPDATES

The following key updates to the RAM inputs were made since the 2019 IRP Progress Report:

1. The load forecast was updated to reflect the 2021 IRP demand forecast assumptions.
2. The hourly draws of the existing PSE wind fleet and new wind resources were based on NREL wind data set of 250 stochastic simulations.
3. The hourly draws of existing PSE solar resources and new solar resources were based on NREL solar data set of 250 stochastic simulations.
4. Colstrip Units 3 & 4 and Centralia were removed.
5. New resources from the 2018 RFP were added.
6. The balancing reserve requirements were updated to include new results for study years 2025 and 2030.

YEARS MODELED. The 2021 IRP time horizon starts in 2022, so PSE modeled a 5-year and 10-year resource adequacy assessment. The first assessment is the 5-year assessment for the period of October 2027 – September 2028. The second assessment is the 10-year assessment for the period of October 2031 – September 2032. The modeled year follows the hydro year (October – September) and allows the full winter and summer seasons to stay intact for the analysis. This is consistent with the NPCC's GENESYS model. If PSE modeled the calendar year, it would break up the winter season (November – February).

PSE also updated the 2023 forecasts from the 2018 NPCC Resource Adequacy Assessment in the RAM model. Since PSE is modeling the years 2027 and 2031, the GENESYS model was updated from the year 2023 to match the years 2027 and 2031. This was done by updating the demand forecast using the Council's demand escalation, updating plant retirements such as Colstrip and Centralia, and including new resources from PSE's portfolio (Skookumchuck and Lund Hill). The detailed updates were discussed earlier in this chapter.

RAM is an annual model. It is run for all hours of the year studied. All of the loss of load events are then added up for the year and accounted for in the annual modeling process. The model is set up to track annual events to a planning margin that is applied at the system peak. Monthly or seasonal RAM metrics are not available for this IRP but are being considered for the next IRP.

Study Year 2027

The incremental impact of each modeling update on the capacity need for the study year 2027 is documented in Figure 7-5. The starting point is the 2019 IRP Process capacity need with Colstrip Units 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-5: Impact of Key Input Revisions for 2027

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2027 - Sep 2028
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	1,867
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2027-2028	960	
	Updated balancing reserves for 2025 Case	918	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	982	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP Load Forecast for October 2027 – September 2028		1,334
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,273
	Updated Lund Hill generation to NREL data		1,291
	Add Golden Hills		1,161
	Add new RFP resource		1,018
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		887
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		881
	Fixed correlations for wind and solar data		907

Figure 7-6 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 907 MW of perfect capacity is needed in the year 2027 to meet the 5 percent LOLP.

Figure 7-6: Reliability Metrics at 5% LOLP for 2027

Metric	Base System – no added resources	System at 5% LOLP – add 907 MW
LOLP	68.84%	4.99%
EUE	5,059 MWh	430 MWh
LOLH	11.06 hours/year	0.83 hours/year
LOLE	12.58 days/year	0.12 days/year
LOLEV	2.49 events/year	0.14 events/year

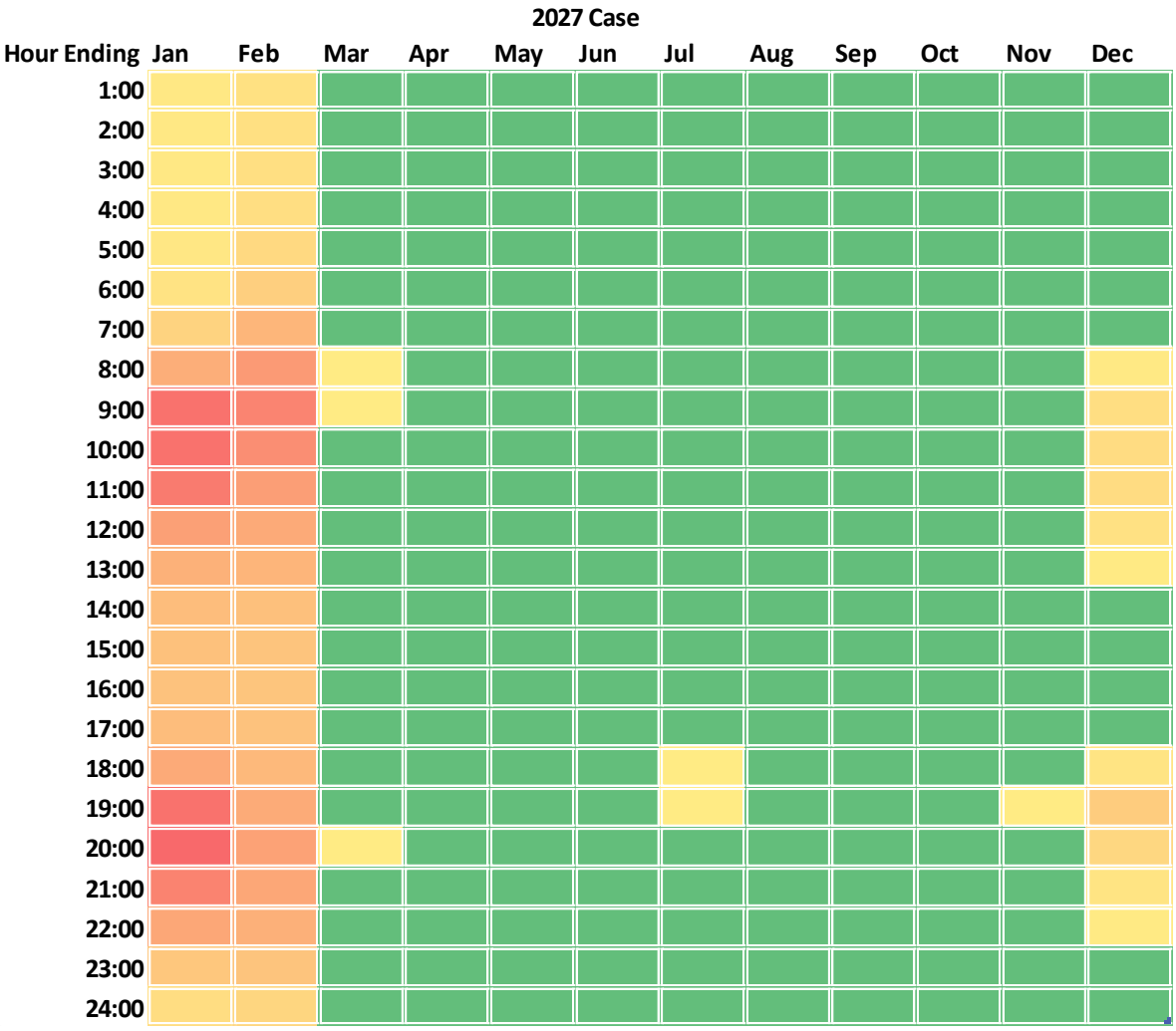
A loss of load event can be caused by many factors, which may include temperature, demand, hydro conditions, plant forced outages and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. Figure 7-7 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February. However, this is the first time that we are seeing events occur in the summer, even though they affect few hours (about 0.04 percent of total hours). Given this result, PSE is still strongly winter peaking; we do not see this changing but will continue to monitor the summer events.

Figure 7-7: Hours of Loss of Load across 7,040 Simulations for 2027

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	4,846	2,893
2	3,296	2,553
3	10	5
4	-	-
5	-	-
6	10	-
7	3	2
8	-	-
9	-	-
10	-	-
11	5	1
12	474	275

Figure 7-8 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-8: Loss of Load Hours for 2027



Study Year 2031

The incremental impact of each modeling update on the capacity need for the study year 2031 is documented in Figure 7-9. The starting point is the 2019 IRP Process capacity need with Colstrip 3 & 4 removed from the PSE portfolio in 2026.

Figure 7-9: Impact of Key Input Revisions for 2031

	REVISIONS	MW Needed for 5% LOLP Oct 2022 - Sep 2023	MW Needed for 5% LOLP Oct 2031 - Sep 2032
2019 IRP Base	2019 IRP Process resource need	685	
	2019 IRP Process resource need, no Colstrip 1 & 2	1,026	2,217
2021 IRP Updates	Updated contracts to include 2018 RFP contracts	968	
	Updated Wholesale Market Purchase Risk model for years 2031-2032	956	
	Updated balancing reserves for 2030 case	1,071	
	Updated transmission assumptions • Add 50 MW BPA contract • Goldendale firm transmission	1,134	
	GENESYS load growth for 2027 and coal plant retirements Updated outage draws and resource capabilities 2021 IRP demand forecast for October 2027 – September 2028		1,635
	Updated Wild Horse, Hopkins Ridge, LSR and Skookumchuck shapes to NREL data		1,581
	Updated Lund Hill generation to NREL data		1,596
	Add Golden Hills		1,469
	Add new RFP resource		1,326
	Demand Forecast • Fixed some errors in March • Updated A/C saturation to align with 2021 IRP demand forecast		1,344
	Fixed generation profile for Lund Hill – discovered error that generation was in DC and updated to AC		1,361
	Fixed correlations for wind and solar data		1,381

Figure 7-10 summarizes the resulting metrics when the LOLP meets the 5 percent standard. The Base System represents the current PSE resource portfolio without any new resources. RAM determined that 1,361 MW of perfect capacity is needed in the year 2031 to meet the 5 percent LOLP.

Figure 7-10: Reliability Metrics at 5% LOLP for 2031

Metric	Base System – no added resources	System at 5% LOLP – add 1361 MW
LOLP	98.45%	5.00%
EUE	19,243 MWh	419 MWh
LOLH	51.90 hours/year	0.86 hours/year
LOLE	11.25 days/year	0.12 days/year
LOLEV	13.80 events/year	0.17 events/year

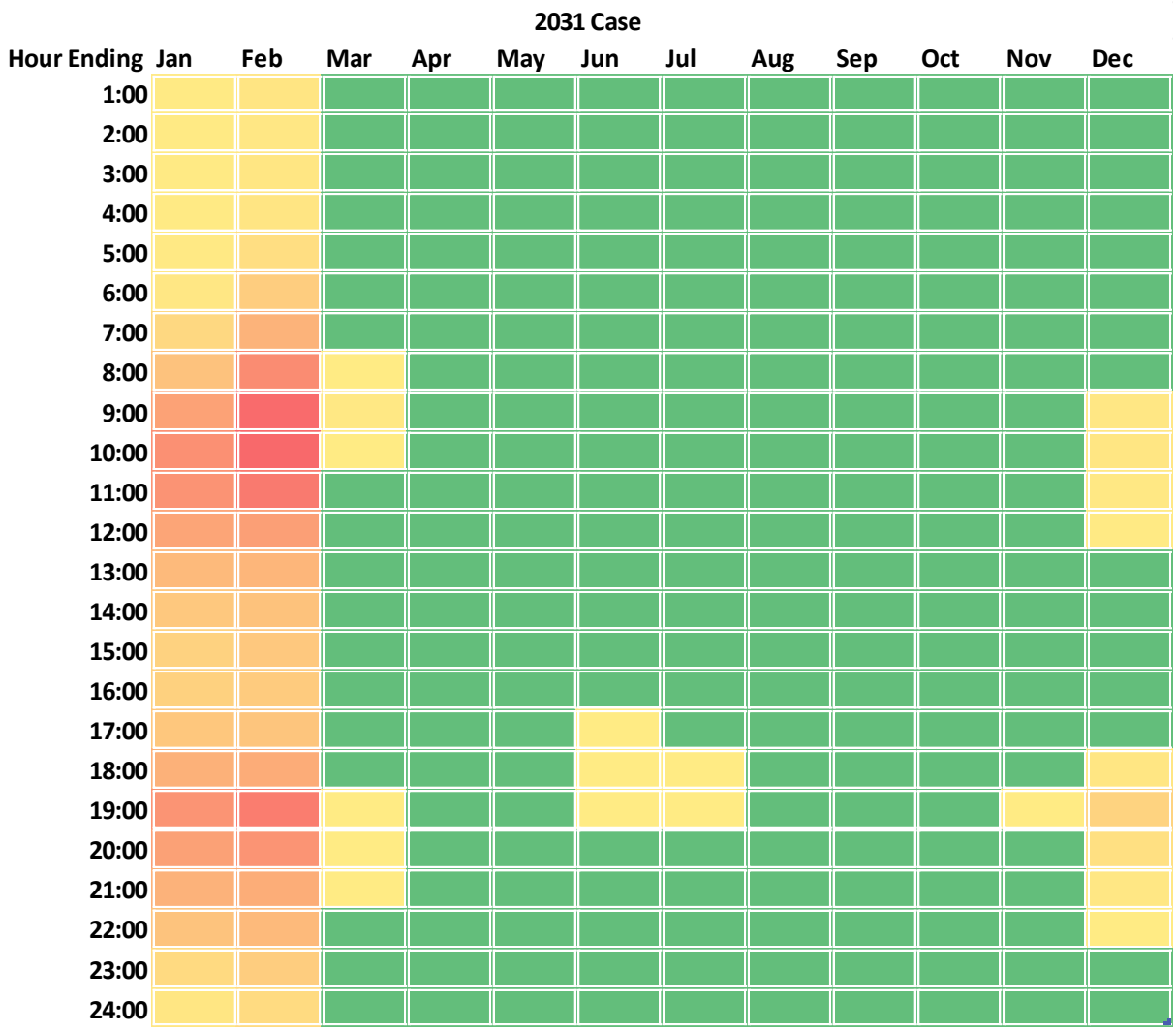
Figure 7-11 shows the number of hours over the 7,040 simulations where a loss of load event occurred. The majority of the loss of load events occur in the winter, during the months of January and February.

Figure 7-11: Hours of Loss of Load across 7,040 Simulations for 2031

Month	Loss of Load (h) Base	Loss of load (h) at 5% LOLP
1	3,860	2,387
2	4,267	3,365
3	40	14
4	-	-
5	-	-
6	12	5
7	4	2
8	4	-
9	-	-
10	-	-
11	9	1
12	325	160

Figure 7-12 is a 12x24 table of the loss of load hours. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, we can see long duration periods, 24 hours or more, with a loss of load event.

Figure 7-12: Loss of Load Hours for 2031



6. RESOURCE NEED

Planning Margin Calculation

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. Using the LOLP methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031. The planning margin is used as an input into the AURORA portfolio capacity expansion model. It is simply a calculation used as an input into the model to make sure that the expansion model targets 907 MW of new capacity in the year 2027 and 1,381 MW in the year 2031. The planning margin calculation for the 2021 IRP is summarized in Figure 7-13. The Total Resources Peak Capacity Contribution is the combined peak capacity contribution of all the existing resources in PSE's portfolio and is also referred to as the effective load carrying capability (ELCC). The peak capacity contribution of planned future resources is described later in this chapter.

Figure 7-13: 2021 IRP Planning Margin Calculation

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	907 MW	1,381 MW
Total Resources Peak Capacity Contribution	3,591 MW	3,599 MW
Short-term Market Purchases	1,471 MW	1,473 MW
Generation Capacity	5,969 MW	6,453 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.7%**	**24.2%**

The total peak capacity contribution of existing and new resources has been updated based on the 2021 IRP ELCC calculation.

Peak Capacity Credit of Resources

The effective load carrying capability (ELCC) of a resource represents the peak capacity credit assigned to that resource. It is calculated in RAM since this value is highly dependent on the load characteristics and the mix of portfolio resources. The ELCC of a resource is therefore unique to each utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of perfect capacity that would yield the same level of reliability. For resources such as a wind, solar, or other energy-limited resources such as batteries and demand response programs, the ELCC is expressed as a percentage of the equivalent perfect capacity. Since the

ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's ELCC numbers with other entities. Some of the ELCCs are higher and some are lower, depending on PSE's needs, demand shapes and availability of the supply-side resources.

The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. For example, LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency, expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries and demand response, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies.

HYDRO RESOURCES CAPACITY CREDITS. The estimated peak contribution of hydro resources was modeled in the RAM. We only modeled the ELCC of PSE owned hydro, Baker River Projects and Snoqualmie Falls. The peak capacity contribution of the Mid-C hydro is based on the Pacific Northwest Coordination Agreement (PNCA) final regulation and represents PSE's contractual capacity less losses, encroachment and Canadian Entitlement.

Figure 7-14: Peak Capacity Credit for Hydro Resources
Based on 5% LOLP Relative to Perfect Capacity

Hydro Resources	ELCC Year 2027 (MW)	ELCC Year 2031 (MW)
Upper Baker Units 1 and 2	90	90
Lower Baker Units 3 and 4	82	79
Snoqualmie Falls	38	37

Figure 7-15: Peak Capacity Credit for Mid-C Hydro Resources
Based on Contractual Capacity Less Losses, Encroachment and Canadian Entitlement

Hydro Resources	Peak Capacity Credit Year 2027 (MW)	Peak Capacity Credit Year 2031 (MW)
Priest Rapids	5	5
Rock Island	121.2	121.2
Rocky Reach	313	313
Wanapum	6.1	6.1
Wells	115	115

THERMAL (NATURAL GAS) RESOURCES CAPACITY CREDITS. The peak capacity contribution of natural gas resources is different than other resources. For natural gas plants, the role of ambient temperature change has the greatest effect on capacity. Since PSE's peak need is at 23 degrees Fahrenheit, the capacity of natural gas plants is set to the available capacity of the natural gas turbine at 23 degrees Fahrenheit. The forced outage of natural gas resources is accounted for in the variability of the 7,040 simulations. As mentioned in the "consistency with regional resource adequacy assessments" section above, PSE uses the "Frequency Duration" outage method in AURORA to simulate unplanned outages (forced outage) for thermal plants. The forced outage is already incorporated into the 907 MW capacity need.

Figure 7-16: Peak Capacity Credit for Natural Gas Resources

THERMAL RESOURCES	Peak Capacity Credit based on 23 degrees (MW)
Sumas	137
Encogen	182
Ferndale	266
Goldendale	315
Mint Farm	320
Frederickson CC	134
Whitehorn 2 & 3	168
Frederickson 1 & 2	168
Fredonia 1 & 2	234
Fredonia 3 & 4	126
Generic 1x0 F-Class Dual Fuel Combustion Turbine	237
Generic 1x1 F-Class Combined Cycle	367
Generic 12x0 18 MW Class RICE	219

WIND AND SOLAR CAPACITY CREDITS. In order to implement the ELCC approach for wind and solar in the RAM, the wind and solar projects were added into the RAM incrementally to determine the reduction in the plant's peaking capacity needed to achieve the 5 percent LOLP level. The wind project's peak capacity credit is the ratio of the change in perfect capacity with and without the incremental wind capacity. The order in which the existing and prospective wind projects were added in the model follows the timeline of when these wind projects were acquired or about to be acquired by PSE: 1) Hopkins Ridge Wind, 2) Wild Horse Wind, 3) Klondike Wind, 4) Lower Snake River Wind, 5) Skookumchuck Wind, 6) Lund Hill Solar, 7) Golden Hills Wind, 8) New RFP Resource, and finally 9) a generic wind or solar resource. Figure 7-17 below shows the ELCC of the wind and solar resources modeled in this IRP.

Figure 7-17: Peak Capacity Credit for Wind and Solar Resources Based on 5% LOLP Relative to Perfect Capacity

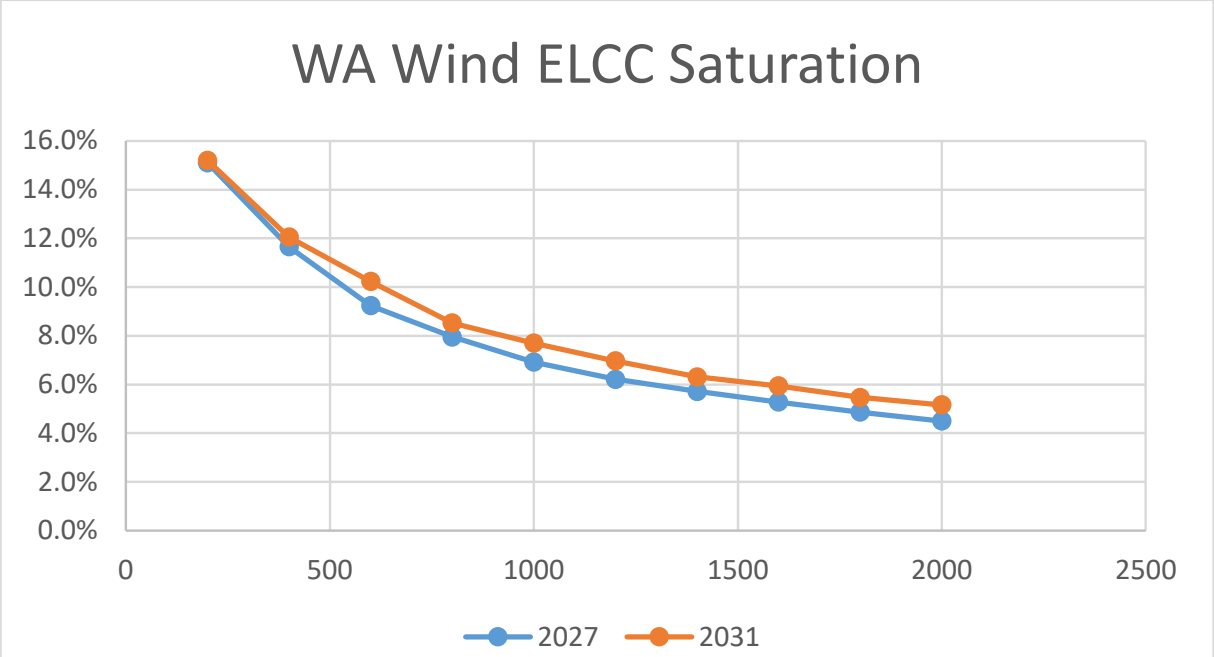
WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027	ELCC Year 2031
Existing Wind	823	9.6%	11.2%
Skookumchuck Wind	131	29.9%	32.8%
Lund Hill Solar	150	8.3%	7.5%
Golden Hills Wind	200	60.5%	56.3%
Generic MT East Wind1	350	41.4%	45.8%
Generic MT East Wind2	200	21.8%	23.9%
Generic MT Central Wind	200	30.1%	31.3%
Generic WY East Wind	400	40.0%	41.1%
Generic WY West Wind	400	27.6%	29.4%
Generic ID Wind	400	24.2%	27.4%
Generic Offshore Wind	100	48.4%	46.6%
Generic WA East Wind[1]	100	17.8%	15.4%
Generic WY East Solar	400	6.3%	5.4%
Generic WY West Solar	400	6.0%	5.8%
Generic ID Solar	400	3.4%	4.3%
Generic WA East Solar[1]	100	4.0%	3.6%
Generic WA West Solar – Utility-scale	100	1.2%	1.8%
Generic WA West Solar – DER Roof	100	1.6%	2.4%
Generic WA West Solar – DER Ground	100	1.2%	1.8%

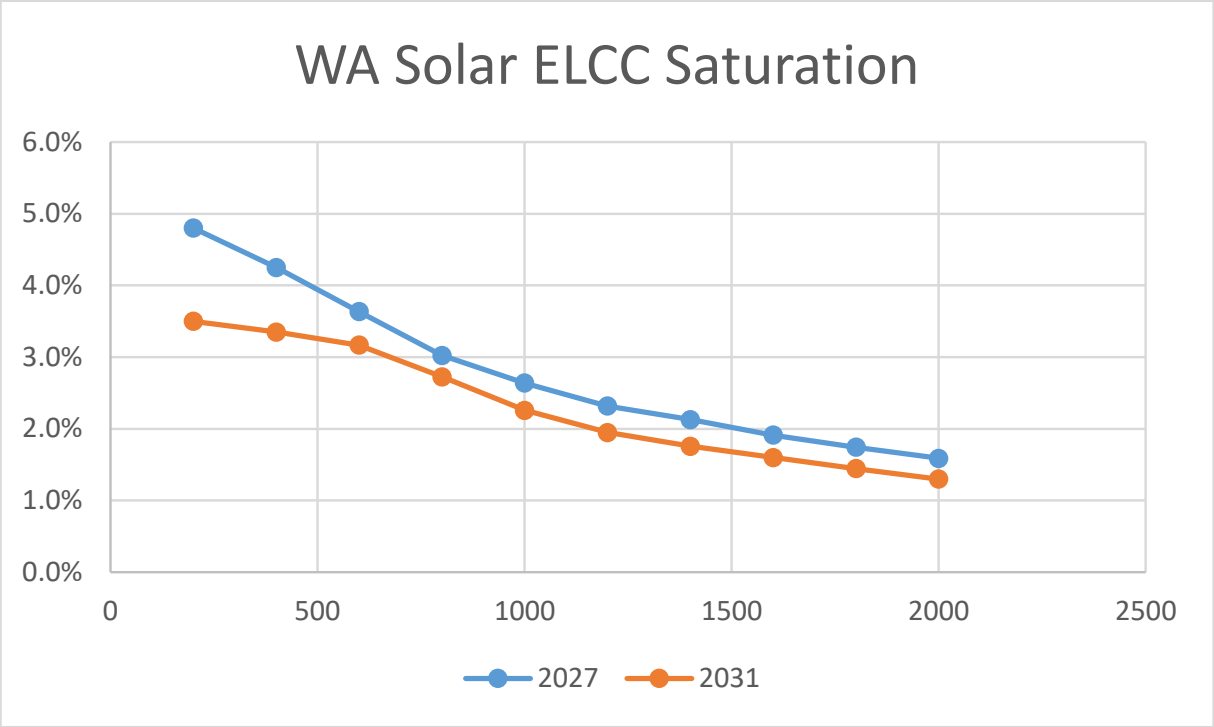
NOTES

1. This ELCC is for the first 100 MW of the resource, the saturation curve for up to 2,000 MW is shown below.

ELCC saturation curves: The peak capacity credit in Figure 7-17 above is for the first 100 MW of installed nameplate capacity for Washington wind and solar. Figure 7-18 below is the ELCC for the next 200 MW and then the next 200 MW after that and so on. The Figure shows a decreasing ELCC as more wind or solar is added to the same region.

Figure 7-18: Saturation Curves for Washington Wind and Solar





STORAGE CAPACITY CREDIT. The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.

As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19.

Since the ELCC is unique to each utility and dependent on load shapes and supply availability, it is hard to compare PSE's peak capacity contributions with other entities. Some of the peak capacity contributions are higher and some lower depending on PSE's needs, demand shapes and availability of the supply-side resources. PSE's winter peak makes it different than the parts of the western interconnect that have a summer peak. Summer peaking events are focused in the late afternoon/evening when the day is the hottest and only last a few hours in the evening, which makes energy storage an ideal solution. However, a winter event can last several days at a time and temperatures can drop low during the night and stay low throughout the day. The low peak capacity contribution for energy storage is because these are short duration resources. As shown in Figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.

Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP

BATTERY STORAGE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	15.8%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	29.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	27.4%
Flow, 6-hr, 73% RT efficiency	100	29.8%	35.6%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	43.8%

HYBRID RESOURCES CAPACITY CREDIT. The capacity contribution of a solar plus battery storage resource is also estimated using EUE. The peak capacity credit of a solar plus battery storage resource is shown in Figure 7-20.

Figure 7-20: Peak Capacity Credit for Hybrid Resource Based on EUE at 5% LOLP

SOLAR + BATTERY RESOURCE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	15.4%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	23.0%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	57.7%

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response program is also estimated using EUE, since this resource is also energy limited like storage resources. The same methodology was used as for storage resources. The peak capacity contribution of demand response is shown in Figure 7-21.

Figure 7-21: Peak Capacity Credit for Demand Response

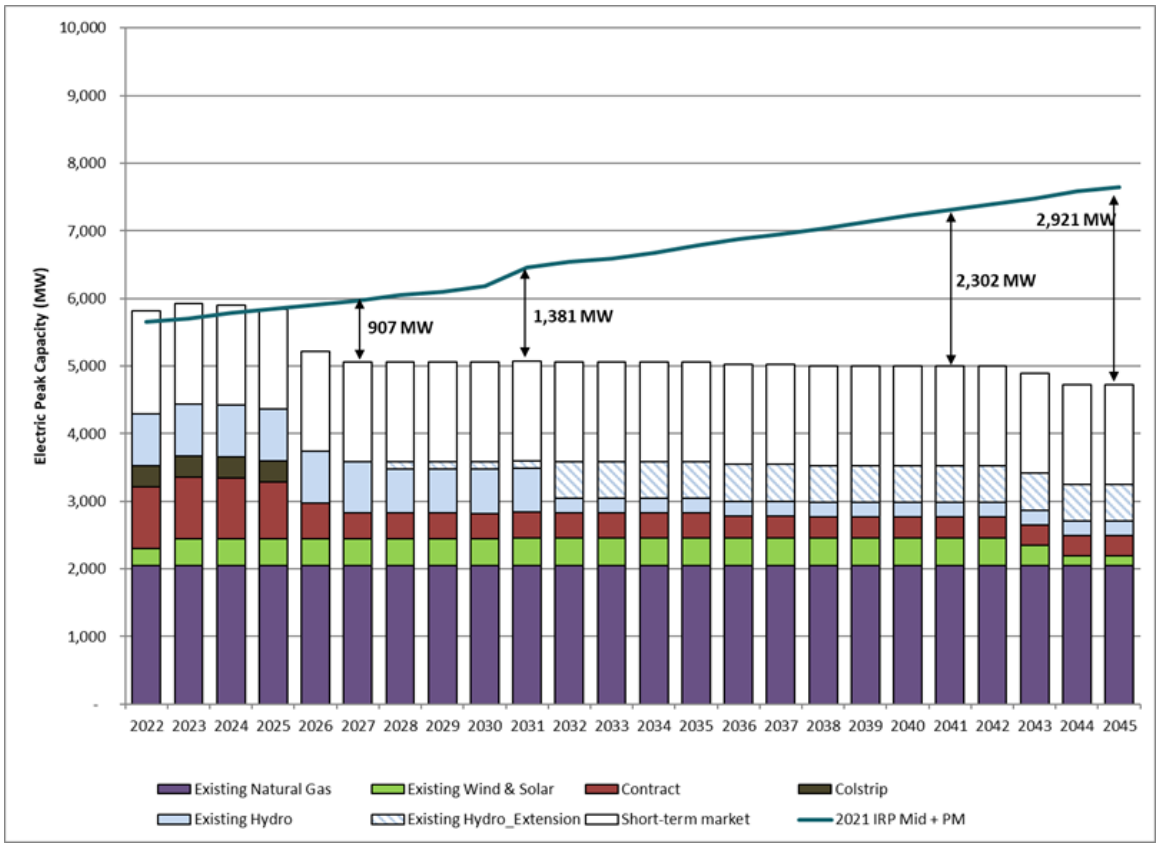
DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

Peak Capacity Need

Figure 7-22 shows the peak capacity need for the mid demand forecast modeled in this IRP. Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW by 2027 and 1,381 MW in 2031 (represented by the teal line in Figure 7-22). This includes a 20.7 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent LOLP planning standard. The graph shows a noticeable drop in PSE's resource stack at the end of 2025. The drop is caused by the elimination of Colstrip 3 & 4 from PSE's energy supply portfolio starting in 2026, which removes approximately 370 MW of capacity, and the expiration of PSE's 380 MW coal-transition contract with TransAlta when the Centralia coal plant is retired at the end of 2025.

The peak capacity deficit assumes that 1,500 MW of market purchases is available to meet peak capacity need. Further analysis of market risk is described below.

Figure 7-22: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



7. ALTERNATIVE FUEL NEED FOR RESOURCE ADEQUACY

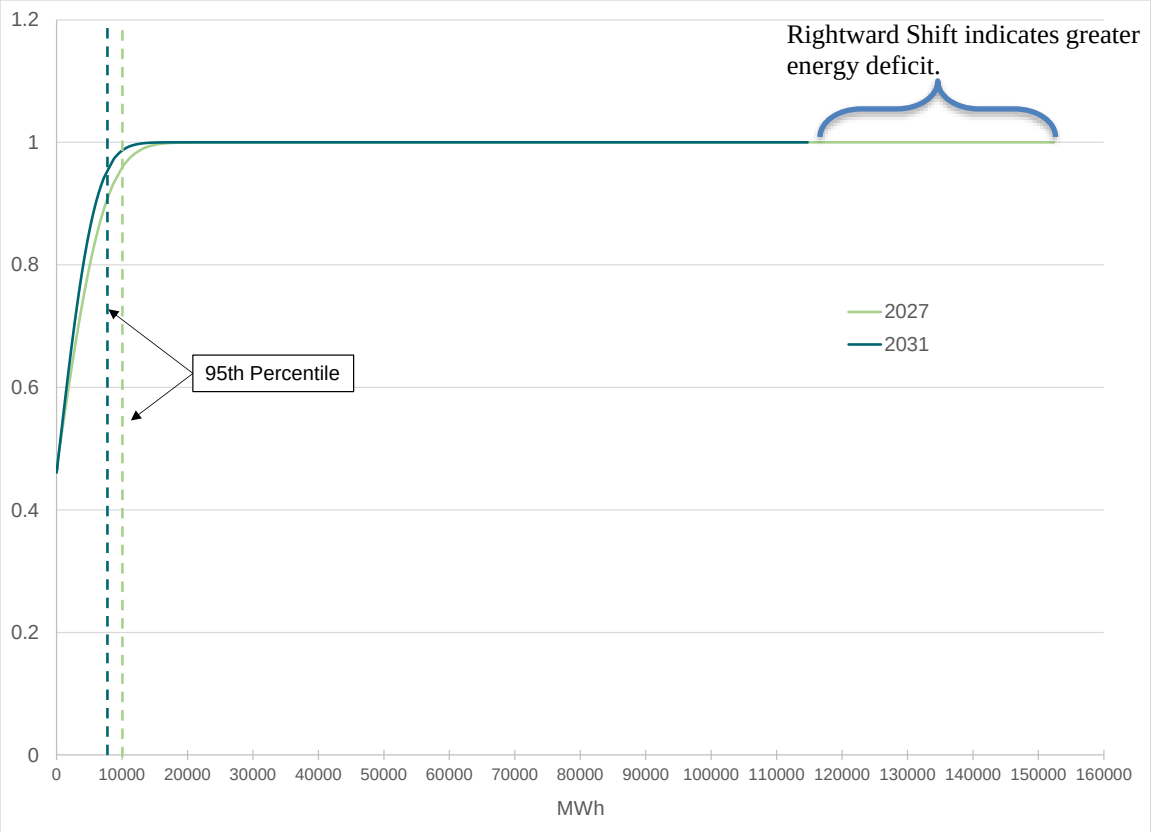
As part of the 2021 IRP, PSE tested CETA-compliant alternative fuels for peakers. When analyzing alternative fuels such as biodiesel, two key issues arise:

1. How many hour many run hours are needed for the year in order to maintain resource adequacy?
2. Is there enough fuel supply?

Incremental outages are examined, using RAM, for loss of load events and hours of outages. Because RAM is a stochastic model performing analysis over 7,040 draws, both the MWh outages and hours of outages are presented as a cumulative distribution.

Figure 7-32 shows the cumulative distribution of generation (MWh) resulting from the incremental outage events for model years 2027 and 2031. This sensitivity was run by removing the peakers form the portfolio and determining how much generation is needed to maintain resource adequacy. The higher the level of capacity that is unable to run due to the lack of peaker generation, the greater the amount of deficit. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the 95th percentile of generation that the peakers are needed to maintain resource adequacy.

Figure 7-32: Cumulative Distribution of Incremental Deficit for Loss of Load Events for All Simulations in MWh/yr



In 95 percent of simulations, to maintain resource adequacy, the peakers are needed to run for 10,000 MWh or less, which is around 15 hours of run time, and the maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[4] on biofuel production, the total annual production of biodiesel in Washington state is 114 MM gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel or about 0.7 percent of Washington State's annual production.

4 / https://www.eia.gov/biofuels/biodiesel/production/

8. MARKET RISK ASSESSMENT

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases under the WSPP contract schedule C,[5] where physical energy can be sourced in the day-ahead or the real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and ensuing procurement. For this IRP, PSE conducted a market risk assessment to evaluate the 1,500 MW assumption in addition to the evaluation completed with the WPCM.

The market risk assessment results in a proposal to increase firm resource adequacy qualifying capacity contracts while limiting the amount of real-time, day-ahead and term market purchases from 1,500 MW to 500 MW by the year 2027 to satisfy peak capacity needs. Support for such a reduction is based on changing market fundamentals in the Western Electricity Coordinating Council (WECC) that impact PSE's ability to access firm market purchases to meet demand. A reduction from 1,500 MW to 500 MW by 2027 provides a realistic and feasible path towards firm capacity for long-term peak capacity planning. The reduction in market purchases used in IRP planning is supported by the reduced capacity and liquidity in the region, coupled with increased volatility at the Mid-C market hub. The events of August 2020 underscore the need to change the IRP planning assumptions; in that event, PSE and other entities were not able to procure additional supply from the market.

Changing WECC Supply/Demand Fundamentals

Generating Capacity Changes

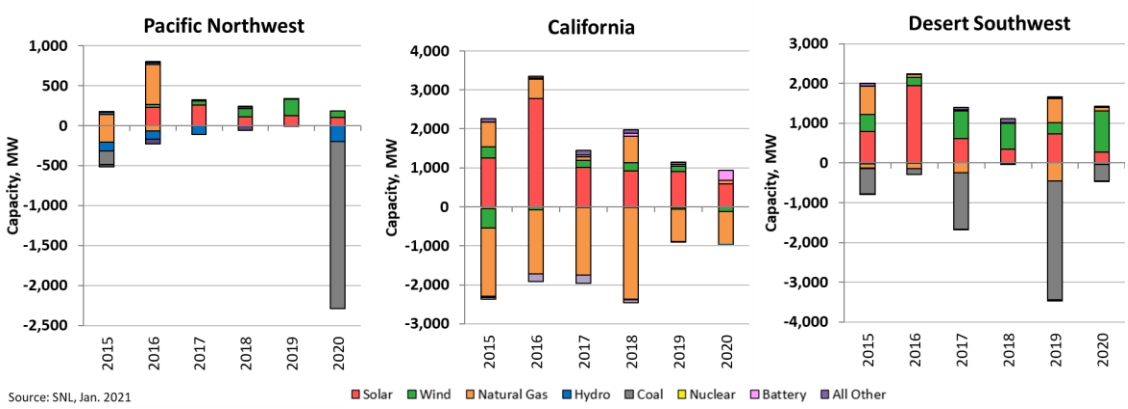
Power market supply/demand fundamentals have changed significantly in recent years. As customers, corporations and state legislatures across the Western Interconnection prefer or require power from clean energy sources, intermittent energy sources – namely wind and solar – have been built while traditional dispatchable capacity resources have been retired or mothballed. The growing capacity deficit in the region has been well documented in several recent studies.[6] Since 2016, nearly 15,000 MW of clean capacity and 500 MW of batteries have been added to

5 / https://www.wspp.org/pages/Agreement.aspx

6 / 2018 Pacific Northwest Loads and Resources Study (White book) (BPA, 2020); Resource Adequacy in the Pacific Northwest (E3, 2019); 2018 Long-Term Reliability Assessment (North American Reliability Corporation and Western Electricity Council, 2018); Pacific Northwest Power Supply Adequacy Assessment for 2023 (Northwest Power and Conservation Council, 2018); Northwest Regional Forecast of Power Loads and Resources: 2020 through 2029 (Pacific Northwest Utilities Conference Committee, 2019); Long Term Assessment of the Load Resource Balance in the Pacific Northwest (Portland Gas and Electric and E3, 2019)

the grid while 12,000 MW of coal and natural gas resources have been retired, as illustrated in Figure 7-23.

Figure 7-23: Capacity Additions and Retirements Since 2016

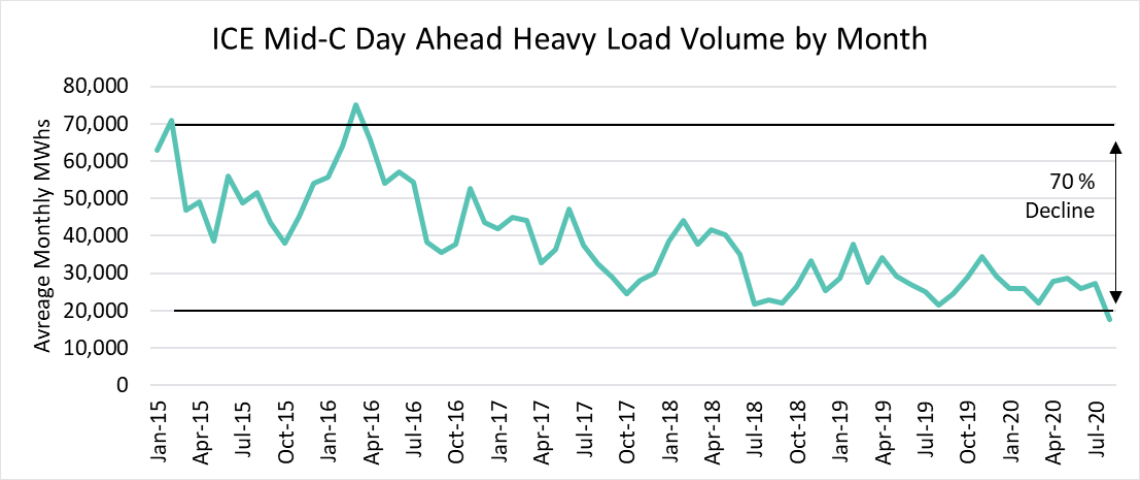


Included in Pacific Northwest thermal retirements are the retirements of Colstrip 1 and 2 in January 2020, which increased PSE's reliance on the short-term market by 300 MW. With less dispatchable generation capacity within the WECC, market supply/demand fundamentals have tightened.

Transaction Volumes and Volatility

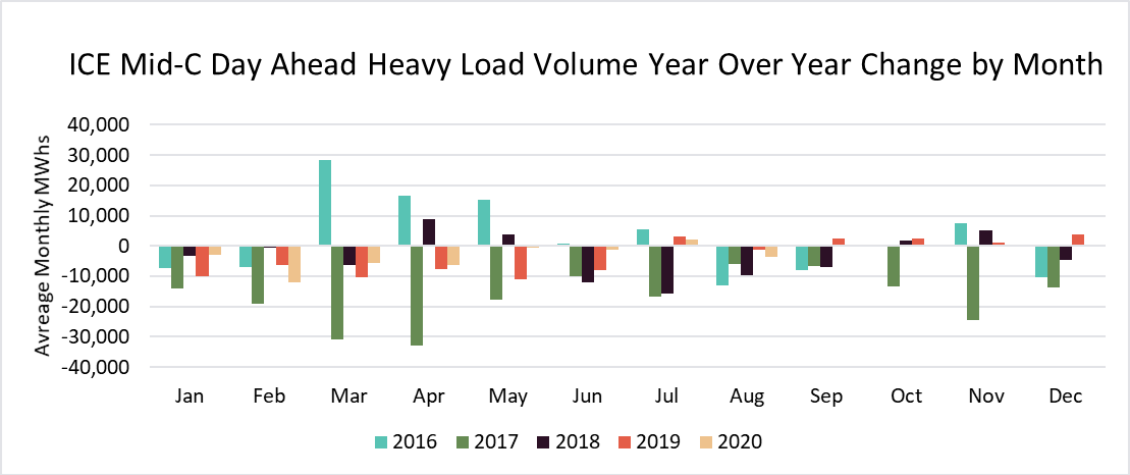
Reductions in traded volume in the day-ahead market also indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available which market participants can trade. This also is suggestive of energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 7-24 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 7-24: Mid-C Day-ahead Heavy Load Volume Timeline



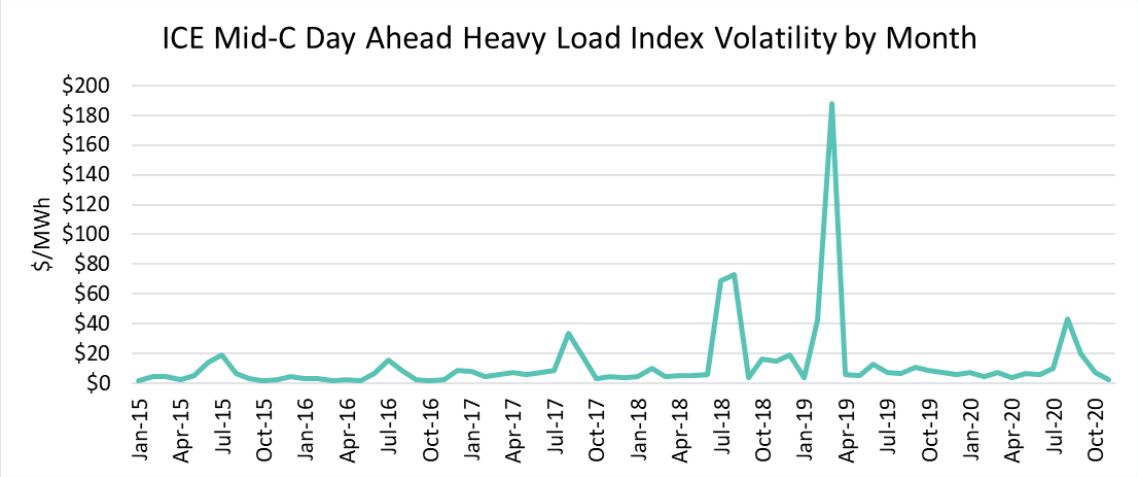
The decline has been consistent in all delivery periods. Figure 7-25 shows the average monthly change in trading volume from one year to the next. Negative bars show a reduction in trading volume while positive bars show an increase in trading volume.

Figure 7-25: Mid-C Day-ahead Heavy Load Volume Monthly Change



Additionally, price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018 when high regional temperatures coincided with forced outages at Colstrip; in March 2019 when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020 during a west-wide heat event. The volatility of day-ahead heavy load prices is presented in Figure 7-26.

Figure 7-26: Volatility of Heavy Load Mid-C Day-ahead Prices



Approach of Regional Investor Owned Utilities

Coinciding with the retirement of legacy baseload capacity and the decline of market liquidity, several regional investor owned utilities (IOUs) have reduced their assumptions of available market capacity in their IRPs. A lack of reliance or a reduced reliance on the market for capacity has precedent as shown in Figure 7-27. While it is difficult to get an exact comparison since IOUs have different resource planning assumptions, hedging and procurement practices, it is clear that PSE's market purchases are higher than other IOUs.

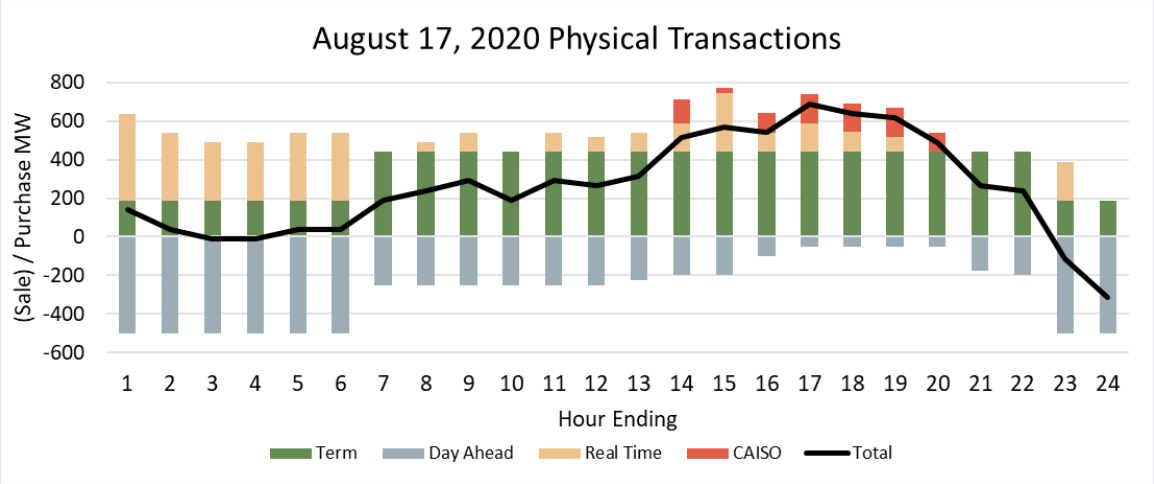
Figure 7-27: Regional IOU Market Reliance

Entity	Planned Summer Market Reliance Limit (MW)	Planned Winter Market Reliance Limit (MW)	Commentary
Avista	330	330	From the draft 2021 IRP. Market purchases are limited to 500 MW during 'unconstrained' hours, and 330 MW during 'constrained' hours
Idaho Power	N/A	N/A	The current IRP (2019) assumes market purchases of 500 MW in the summer and 425 MW in the winter. Specific market purchase limits are not defined in the IRP.
PacifiCorp	500 – Aggregate 150 – Mid-C Seasonal HLH	1000 – Aggregate 0 – Mid-C Seasonal HLH	Proposed Front Office Transaction Limits for the 2021 IRP cycle.
Portland General	50	0	Estimates from *Long Term Assessment of the Load Resource Balance in the Pacific Northwest* (Portland Gas and Electric and E3, 2019)
Puget Sound Energy	1,500	1,500	PSE counts historical energy offers at the Mid-C hub as available capacity to meet peak demand needs in the winter and summer.

Events of August 2020

Amid a west-wide heat wave lasting from August 14, 2020 to August 19, 2020, several balancing authority areas (BAAs) in the Western Interconnect declared various stages of energy emergency. This included the CAISO, which declared a stage 3 emergency and cut firm load on August 14 and 15. PSE's BAA declared a stage 1 emergency on August 17, 2020 as there was concern about the ability to procure capacity to meet load and contingency reserve obligations during hours ending 15 – 18 (3pm – 6pm). PSE's BAA ultimately did not progress further into emergency conditions and all load and contingency reserves were met. PSE ultimately relied on 400-505 MW of market purchases using WSPP-C contracts and 25 to 150 MW of exports from the CAISO, but could not procure additional capacity. This was significantly less than the 1,500 MW of market purchases that has been assumed to be available to meet demand in PSE's IRP. PSE's total market reliance on August 17, 2020 is shown in Figure 7-28. The different color bars show when the energy was procured for each hour on the day of August 17, 2020. Limited amount of imports from California were available.

Figure 7-28: Physical Transactions (MW) on August 17, 2020



Peak Capacity Need

ADJUSTED PEAK CAPACITY NEED. The reduction in market purchases to 500 MW increases the peak capacity deficit in 2027 from 907 MW to 1,853 MW. The planning margin calculation for the adjusted peak capacity need is summarized in Figure 7-29.

Figure 7-29: 2021 IRP Planning Margin Calculation with Declining Market Reliance

	Winter Peak 2027	Winter Peak 2031
Peak Capacity Need to meet 5% LOLP	1,853 MW	2,263 MW
Total Resources Peak Capacity Contribution	3,586 MW	3,599 MW
Short-term Market Purchases	500 MW	500 MW
Generation Capacity	5,940 MW	6,362 MW
Normal Peak Load	4,949 MW	5,199 MW
Planning Margin	**20.0%**	**22.4%**

Figure 7-30 below shows the annual change in peak deficit for the declining market reliance and converting the short-term energy purchases to firm resource adequacy qualifying capacity contracts. The market availability at peak gradually declines over a 5-year period at 200 MW per year through to the year 2027. The gray area is the total available transmission to the Mid-C market. This position is usually left open to the short term market, but based on market availability, the open position will be reduced to 500 MW by 2027 with the remaining available transmission used for firm resource adequacy qualifying capacity purchases.

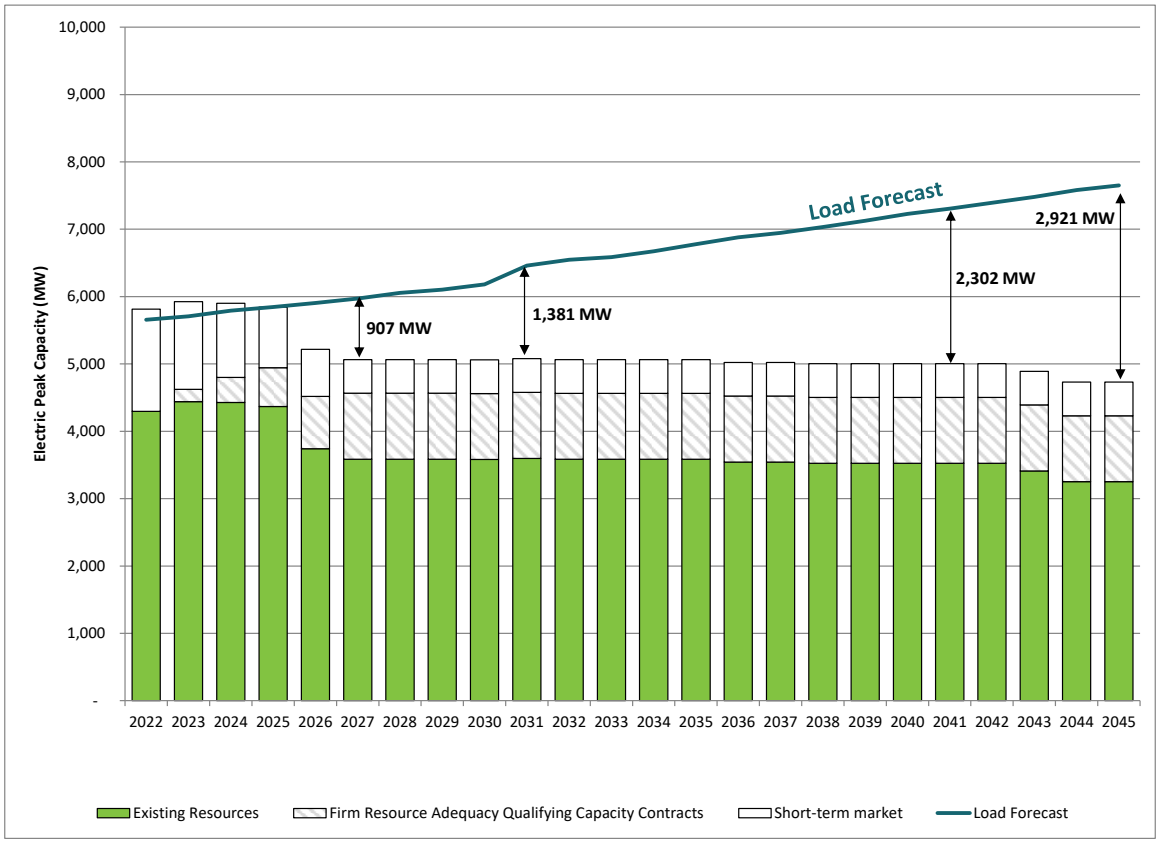
Figure 7-30: Short Term Market Purchases converted to Firm Resource Adequacy Qualifying Capacity Contracts

Year	Available Mid-C transmission (MW)	Short Term Market Purchases (MW)	Firm RA Qualifying Capacity Contracts (MW)
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

After 2031, the short term market stays at 500 MW and the firm resource adequacy qualifying capacity contracts at 979 MW.

Figure 7-31 shows the peak capacity need; the grey dashed bars highlight the reduced market purchases described above. Before any additional demand-side resources, peak capacity needed to meet the demand forecast plus planning margin – after reducing market purchases at peak – is 1,853 MW by the year 2027 and 2,263 MW by the year 2031.

Figure 7-31: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



9. TEMPERATURE SENSITIVITY

PSE committed to run a future temperature sensitivity as a way to begin to evaluate the impacts of climate change. This sensitivity was for the demand forecast only; PSE did not adjust hydro or wind for the adjusted temperature analysis. PSE relies on the Bonneville Power Administration (BPA) to do hydro modeling, and then PSE receives the data through the Pacific Northwest Coordination Agreement Hydro Regulation. This data has long been used by various organizations to estimate hydro variability. PSE will continue to align with BPA hydro modeling and will analyze any new data as it becomes available to better understand the impacts of climate change to the hydro system. There are three components to the temperature sensitivity analysis:

1. An updated energy demand forecast;
2. An alternative resource adequacy analysis; and
3. A portfolio sensitivity using the Aurora Long Term Capacity Expansion portfolio model.

The energy demand forecast is described in Chapter 6. The resource adequacy analysis adjustments made to account for the alternate temperatures is described below and the results of the portfolio sensitivity can be found in Chapter 8.

The base RAM analysis includes 88 historic temperature years. To create a wider range of possible future temperatures, and consistent with the stakeholder-selected energy demand forecast assumptions, PSE used three models that the NPCC has been using in its resource adequacy analyses. These models (CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA) are the product of a recent project by Bonneville Power Administration, U.S. Army Corps of Engineers and the Bureau of Reclamation that down-scaled global climate models to be more specific to the Northwest region. Each of these three models is on the Representative Concentration Pathway of 8.5, which some would argue is a “business as usual” pathway, while others would argue is a more extreme climate warming scenario.

The three models represent different amounts of warming over time. CanESM2_BCSD forecasts 0.9 degree of warming per decade, CCSM4_BCSD forecasts 0.9 degrees of warming per decade, and CNRM-CM5_MACA forecasts 0.5 degrees of warming per decade. While CanESM2_BCSD and CCSM4_BCSD have similar warming trends per decade, the temperatures from the two models are very different from year to year, and CanESM2_BCSD is a full degree warmer than CCSM4_BCSD, on average, over time.

PSE did not change the peak temperature assumptions for this analysis, because while average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Therefore, and as a result, the peak demand forecast did not change.

For each of the three models analyzed, weather from the future decade in which the RA scenario takes place was used; that is, weather from 2020 through 2029 was used for the 2027 to 2028 RAM run, and weather from 2030 to 2039 was used for the 2031 to 2032 RAM run. The 10 years of weather from the three models was repeated almost three times and coupled with 88 economic and demographic draws to create 88 future hourly loads for the RA model. This mirrors the methodology used in the NPCC resource adequacy analysis.

Using the LOLP methodology with the data from this temperature analysis, it was determined that 328 MW of capacity is needed by the year 2027 and 1,019 MW of capacity by the year 2031. The results of this sensitivity are compared with the base RAM results in Figure 7-32.

Figure 7-32: Peak Capacity Need

	Base	Temperature Sensitivity
2027 peak need	907 MW	328 MW
2031 peak need	1,381 MW	1,019 MW

The temperature analysis results showed more loss of load events in the summer caused by inadequate supply while in the base analysis, most loss of load events occurred in the winter season as shown in Figure 7-33. This shift in loss of load events from the winter to summer affects the peak capacity credit of resources. Resources with higher capacities in the summer, such as solar, now have higher peak capacity credit while those with strong winter generation become less effective with a lower peak capacity credit.

Figure 7-33: Frequency of Loss of Load Events by Month and Hour of Day for Model Years 2027 and 2031, Base Scenario and Temperature Sensitivity
(red indicates more loss of load events, green indicates zero loss of load events)

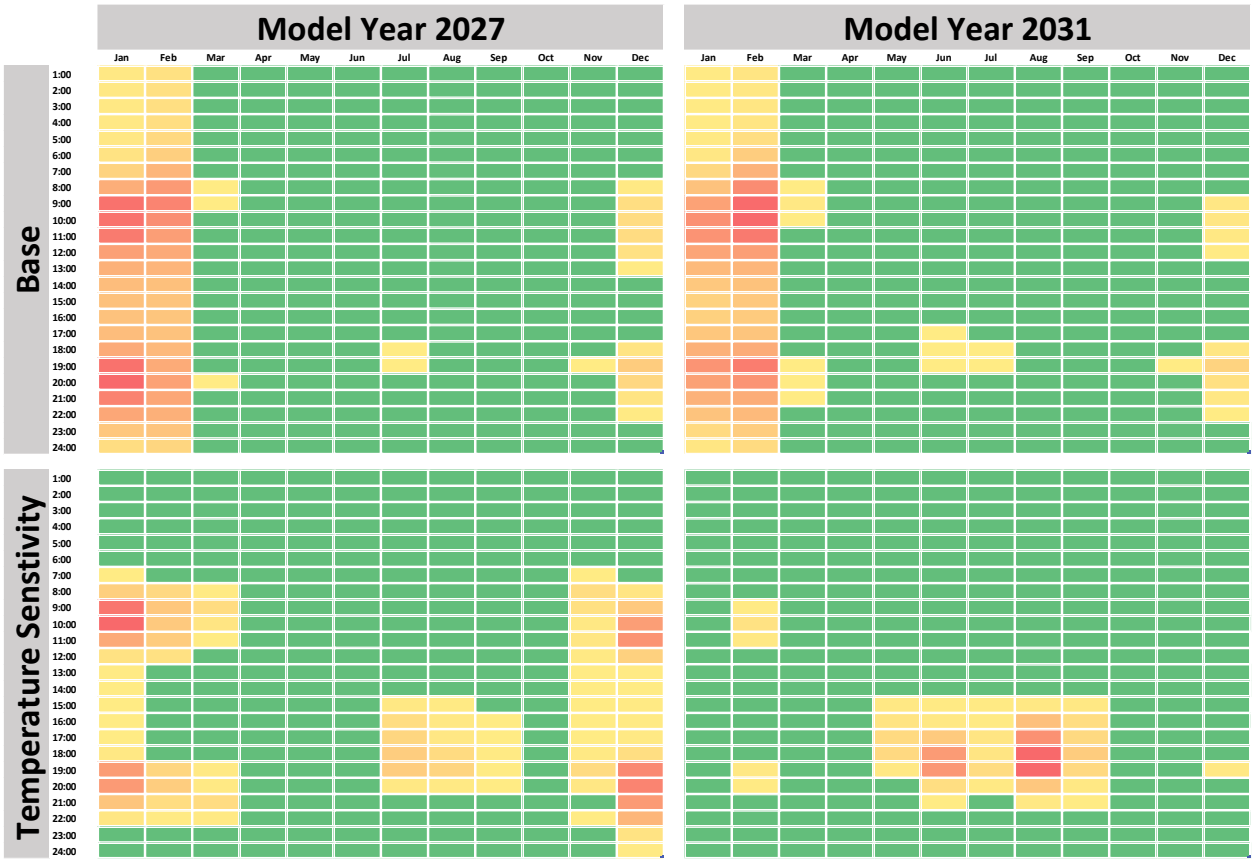


Figure 7-34 presents the effective load carrying capability of the generic resources for the temperature sensitivity as compared to the base scenario. The RAM results presented here were used to develop the inputs for the AURORA portfolio model.

Figure 7-34: Effective Load Carrying Capability for model years 2027 and 2031, Base Scenario and Temperature Sensitivity

WIND AND SOLAR RESOURCES	Capacity (MW)	ELCC Year 2027		ELCC Year 2031	
		Base Scenario	Temp. Sensitivity	Base Scenario	Temp. Sensitivity
Existing Wind	823	9.6%	6.8%	11.2%	6.7%
Skookumchuck Wind	131	29.9%	17.6%	32.8%	9.2%
Lund Hill Solar	150	8.3%	30.3%	7.5%	54.3%
Golden Hills Wind	200	60.5%	49.3%	56.3%	39.3%
Generic MT East Wind1	350	41.4%	28.5%	45.8%	28.1%
Generic MT East Wind2	200	21.8%	13.1%	23.9%	17.7%
Generic MT Central Wind	200	30.1%	23.1%	31.3%	20.9%
Generic WY East Wind	400	40.0%	29.1%	41.1%	32.7%
Generic WY West Wind	400	27.6%	27.2%	29.4%	34.0%
Generic ID Wind	400	24.2%	25.6%	27.4%	28.0%
Generic Offshore Wind	100	48.4%	38.6%	46.6%	27.6%
Generic WA East Wind	100	17.8%	7.8%	15.4%	12.0%
Generic WY East Solar	400	6.3%	13.5%	5.4%	32.5%
Generic WY West Solar	400	6.0%	16.2%	5.8%	36.3%
Generic ID Solar	400	3.4%	16.0%	4.3%	47.3%
Generic WA East Solar	100	4.0%	21.6%	3.6%	45.6%
Generic WA West Solar – Utility-scale	100	1.2%	7.6%	1.8%	20.2%
Generic WA West Solar – DER Roof	100	1.6%	7.6%	2.4%	19.4%
Generic WA West Solar – DER Ground	100	1.2%	7.6%	1.8%	20.2%
BATTERY STORAGE					
Lithium-ion, 2-hr, 82% RT efficiency	100	12.4%	34.2%	15.8%	36.0%
Lithium-ion, 4-hr, 87% RT efficiency	100	24.8%	66.6%	29.8%	68.8%
Flow, 4-hr, 73% RT efficiency	100	22.2%	61.6%	27.4%	63.8%
Flow, 6-hr, 73% RT efficiency	100	29.8%	79.2%	35.6%	84.8%
Pumped Storage, 8-hr, 80% RT efficiency	100	37.2%	89.2%	43.8%	97.8%
SOLAR + BATTERY RESOURCE					
Generic WA Solar, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	14.4%	22.0%	15.4%	56.6%
Generic WA Wind, lithium-ion, 25MW/50MWh, 82% RT efficiency	100	23.6%	26.0%	23.0%	17.8%
Generic MT East Wind, pumped storage, 8-hr, 80% RT efficiency	200	54.3%	73.0%	57.7%	64.0%

DEMAND RESPONSE					
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	60.4%	31.6%	61.4%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	69.8%	37.4%	80.8%

It is important to note that this is one model of possible weather changes and provides a preliminary view of the possible impact of warming temperatures. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made that inform the preferred portfolio in this IRP.

PSE will continue to model weather trends under different scenarios to try to better understand how not only extreme summer events can affect resource adequacy, but also to ensure we are planning for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past, there have been three separate regional energy events outside of PSE's control, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipate future changes to the resource adequacy analysis to include both a winter and summer resource adequacy analysis, and will work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.



8 Electric Analysis

This chapter presents the results of the electric analysis.

8 Electric Analysis

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1. ANALYSIS OVERVIEW

The electric analysis in the 2021 IRP followed the six-step process outlined below. Steps 1, 3, and 4 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Establish Resource Need
Three types of resource need are identified: peak capacity need, energy need and renewable need.

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 5 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 6 presents the 2021 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Analyze Alternatives and Portfolios Using Deterministic and Stochastic Risk Analysis
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.

- All scenarios and sensitivities were analyzed using deterministic optimization analysis.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

- Four portfolios were analyzed using stochastic risk analysis.

4. Analyze Results
Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions for the preferred portfolio.

- Results of the analysis are presented in this chapter and in Appendix H.

5. Develop Resource Plan

Chapter 3 describes the reasoning behind the strategy chosen for this preferred portfolio.

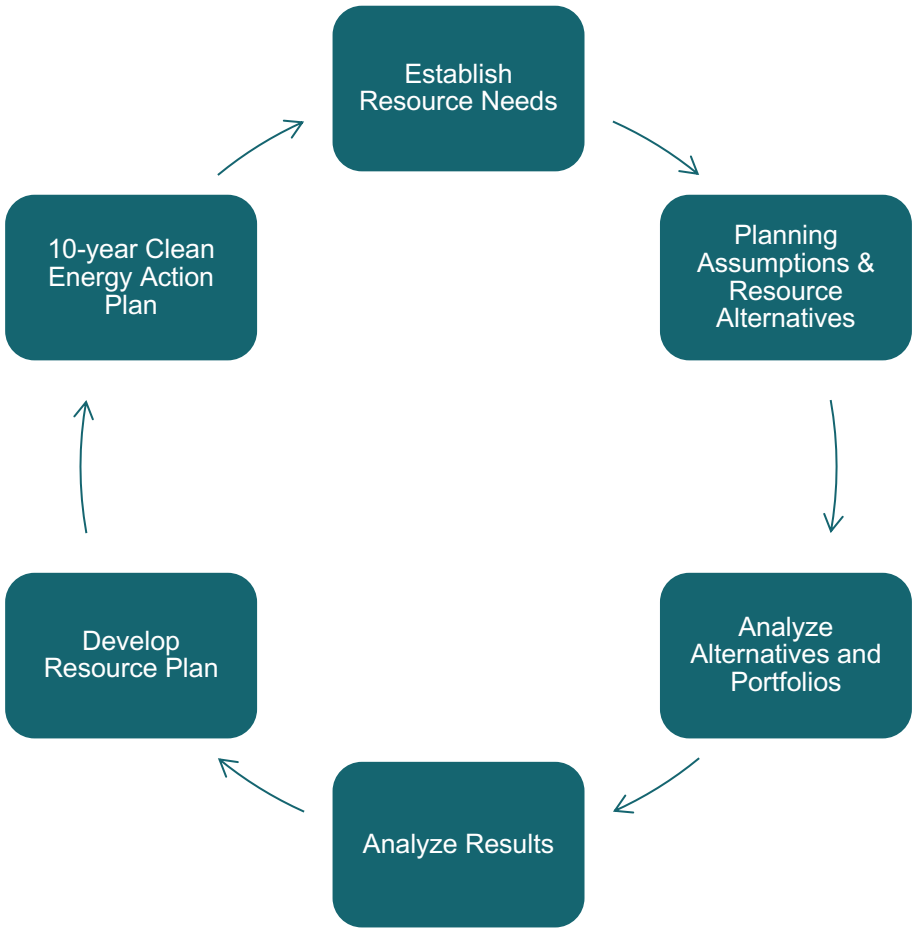
6. Create the 10-year Clean Energy Action Plan

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the IRP Action Plan and the 10-year Clean Energy Action Plan.

- The Action Plan is presented in the Executive Summary, Chapter 1.
- The 10-year Clean Energy Action Plan is presented in Chapter 2.

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



2. SUMMARY OF SUBSTANTIVE CHANGES

The 2021 IRP marks a major departure from past IRPs due in large part to the passage of the Clean Energy Transformation Act. Changes in technology, updates to datasets and other advances have also contributed to differences in the 2021 IRP. This section provides a summary of the substantive changes from the 2017 IRP to the 2021 IRP.

ELECTRIC POWER PRICES. Several updates were made to the development of the electric price model. AURORA, the power system software used for electric price simulations, was updated to version 13.4 in the 2021 IRP from version 12.3 in the 2017 IRP. In addition, the AURORA Zonal database was updated to the "2018 version 1" release in the 2021 IRP from the "2016 version 3" release used in the 2017 IRP. A detailed account of all updates to the electric price model is provided throughout Chapter 5 and Appendix G.

GENERIC RESOURCE COSTS. In the 2021 IRP, PSE developed a new process for obtaining generic resource costs. In past IRPs, PSE has relied on consultants to estimate generic resource costs. In the 2021 IRP, PSE aggregated publically available generic resource costs from a variety of sources. These data were presented to stakeholders during a public meeting and stakeholder input was used to refine generic resource cost assumptions. This framework mirrors the generic resource cost development process used by the Northwest Power and Conservation Council's Generic Resource Advisory Group.

LEGISLATION. In 2019, the Clean Energy Transformation Act (CETA) passed into law. CETA set forth aggressive targets for clean and non-emitting resources. Investor-owned utilities are required to obtain 80 percent of energy sales from non-emitting resources by 2030 and 100 percent of energy sales from non-emitting resources by 2045. This dramatically increases the 15 percent renewable portfolio standard established by RCW 19.285. Furthermore, CETA introduced the need to incorporate the social cost of greenhouse gases and the equitable distribution of customer benefits in the resource planning process.

RESOURCE ADEQUACY MODEL. Between the 2017 IRP and the 2021 IRP, PSE completely overhauled its resource adequacy model. This included moving from a SAS based model to a Python based model that incorporates inputs from regional resource adequacy metrics. A full description of the new resource adequacy model is available in Chapter 7.

ELECTRIC PORTFOLIO MODEL. During the three years since the last IRP was filed, PSE has made significant improvements to the portfolio modeling process. For the 2017 IRP, PSE used an Excel-based model called the Portfolio Screening Model (PSM). This annual model relied on AURORA to dispatch the resources, then the data was pulled into PSM where a solver was added to Excel for the linear programming optimization model. By moving the LP optimization model directly into AURORA, PSE is able to evaluate the economic retirement of resources, increase the selection of new generic resources, model energy storage and hybrid resources, and a utilize a more robust solver engine.

STOCHASTIC MODEL. Since the 2017 IRP, PSE has moved stochastic modeling from a simple SAS model to a full dispatch and forecasting model in AURORA. The SAS model used in 2017 looked at historical trends to forecast out a range of monthly electric prices. By moving the electric price model into AURORA, PSE is able to achieve a more forward looking forecast based on the new legislation and changing mix of resources in the region. In the new stochastic model, no historical data is used, only forward looking changes in the region. AURORA then runs a complete dispatch of resources by hour for each draw and produces a forecast of hourly electric prices instead of monthly prices.

CONSERVATION POTENTIAL ASSESSMENT. In the 2017 IRP, the conservation potential assessment (CPA) was conducted by third-party Navigant Consulting. In the 2021 IRP, PSE retained a different consultant, CADMUS, to conduct the CPA. A full description of the CPA is available in Appendix E.

DEMAND FORECAST. The 2017 IRP base demand forecast was based on 2016 macroeconomic conditions such as population growth and employment; the forecast for the 2021 IRP is based on 2020 macroeconomic conditions. The updates to inputs and equations are documented in Chapter 6.

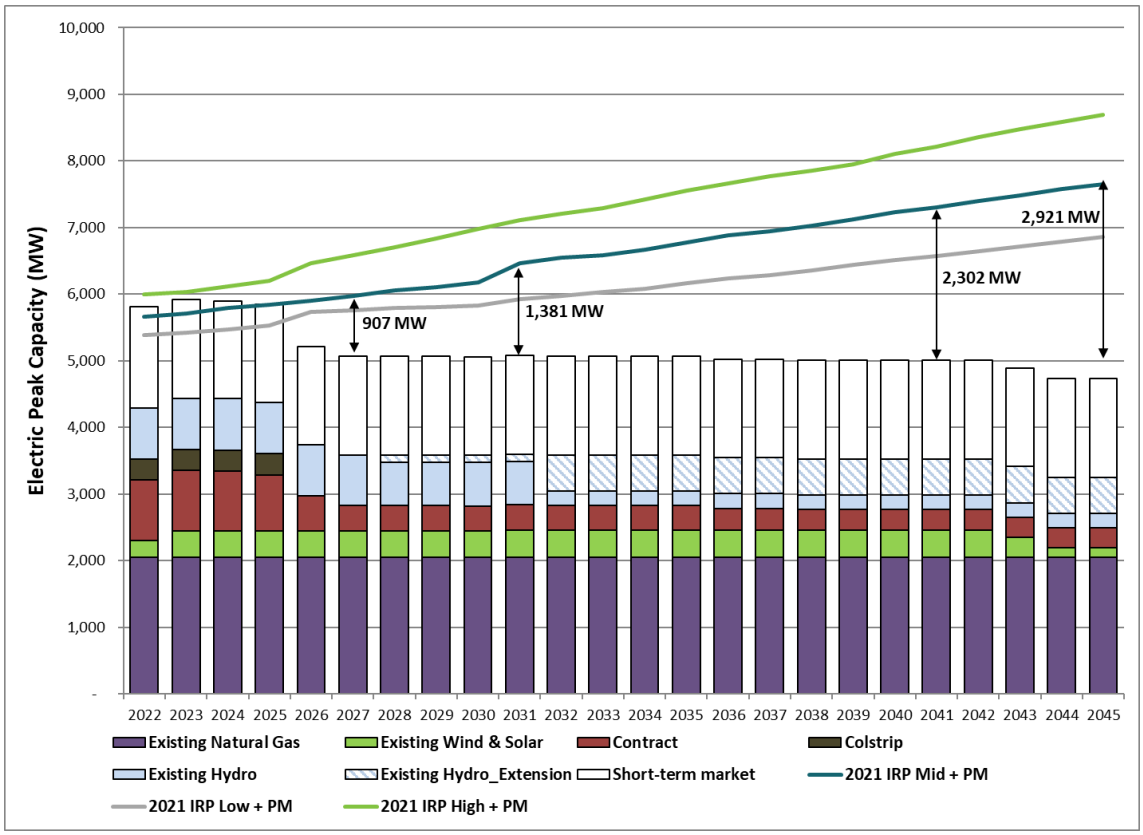
3. RESOURCE NEED

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: 1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; 2) hourly energy, i.e., does PSE have enough energy available in every hour to meet customer's electricity needs; and 3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Using the loss of load probability (LOLP) methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031 before any new conservation. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM).

Figure 8-2: Electric Peak Capacity Need
(physical reliability need, peak hour need compared with existing resources)



Energy Need

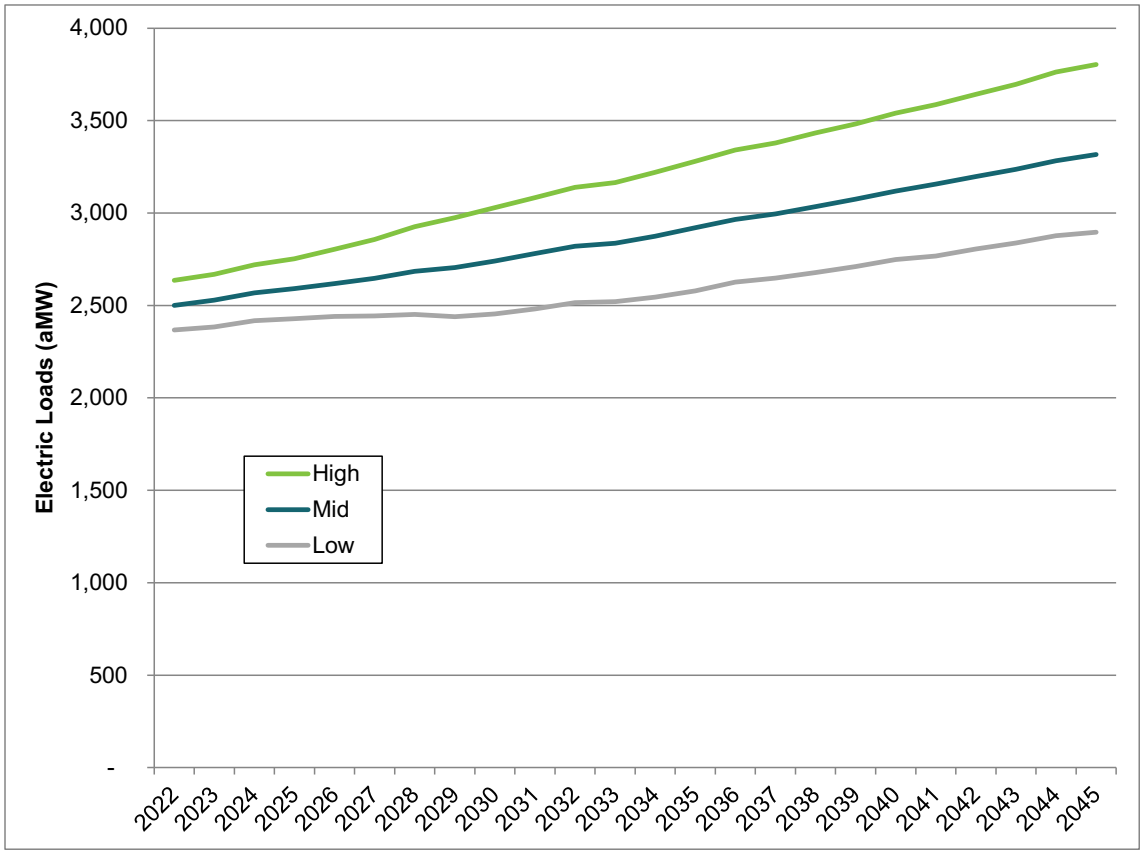
Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed in every hour to meet physical loads, but our models also examine how to do this most economically.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. In fact, PSE could generate significantly more energy than needed to meet our load on an average monthly or annual basis, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economical; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like

wind is available, PSE's models will displace higher-cost market purchases and use the wind to meet the energy need.

Figure 8-3 illustrates the company's energy demand forecast across the planning horizon, based on the energy demand forecast for the Mid, High and Low Scenarios. The Mid Demand Scenario starts at 2,500 aMW in 2022 and grows to 2,740 aMW by 2030 and 3,316 aMW by 2045.

Figure 8-3: Annual Demand Forecast



Renewable Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) that requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the Energy Independence Act (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements.

Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables needed. Achieving demand-side resource targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. The first line of the table provides the estimated demand forecast in the year 2030 before demand-side resources (conservation) are applied. From this value, energy savings from conservation, line losses to adjust the demand forecast to retail sales, load reducing customer programs and PURPA generation[1] are subtracted to yield the sales net of conservation and customer programs (20.4 million MWh). Eighty-percent of this value represents the raw renewable need for 2030 (16.3 million MWh). From this value, existing renewable generation is subtracted to obtain the need for new renewable and non-emitting resources (7.6 million MWh).

Demand-side resources are optimized within the portfolio model and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

1 / The Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of generating resources known as qualifying facilities. Energy from qualifying facilities is included in this line item.

Figure 8-4: Calculation of 2021 IRP Renewable Need for 2030

	MWh
2030 Estimated Demand Forecast before Conservation[1]	24,004,160
Conservation: Codes & Standards, Solar PV	(774,387)
Line Losses	(1,579,625)
Load Reducing Customer Programs & PURPA	(1,243,449)
Sales Net of Conservation and Customer Programs	20,406,699
80% of Estimated Net Sales	16,325,360
Existing Non-emitting Resources[2]	(8,691,268)
Need for New Renewable/Non-emitting Resources	7,634,092

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022
2. Assumes normal hydro conditions and P50 wind and solar

Figure 8-5 below illustrates the renewable energy need for both RCW 19.285 and CETA based on the mid demand forecast, before any additional demand-side resources are added.

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements (before demand-side resources)

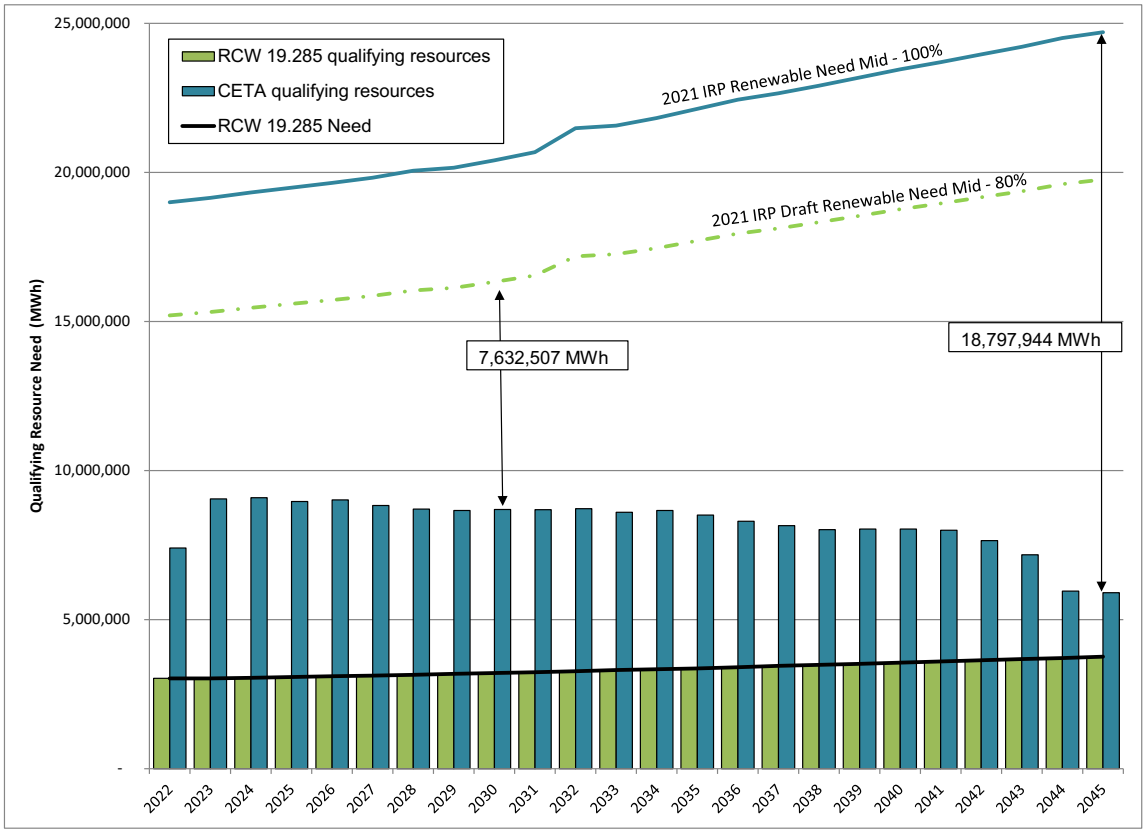
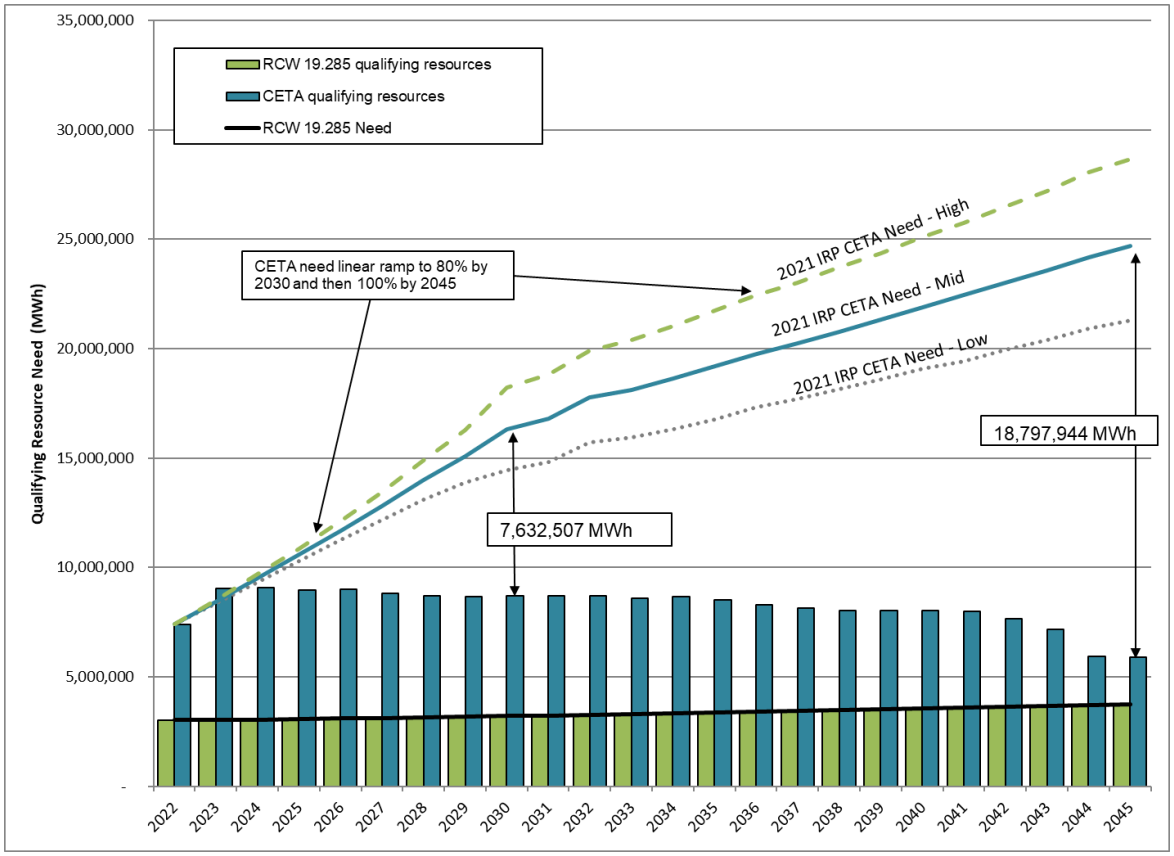


Figure 8-6 below assumes a linear ramp to reach the CETA 80 percent clean energy standard in 2030 and 100 percent clean energy standard in 2045. The linear ramp is needed to ensure that the portfolio model gradually adds resources to meet clean energy standards, rather than waiting until the final year before a goal must be achieved to add them. The linear ramp starts in 2022, as the IRP assumes all new resources are self-builds that will take at least two years before becoming operational. Since the IRP analysis starts in 2022, the earliest a resource can be built is 2024.

Figure 8-6: Renewable Need and Linear Ramp for CETA (before demand-side resources)



4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[2] The customer benefit analysis is used to inform the equitable distribution of burdens and benefits in the resource planning process to ensure that all customers are benefiting from the transition to clean energy.

Deterministic Portfolio Optimization Analysis

All scenarios and sensitivities are subjected to deterministic portfolio analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio – that is, the lowest cost mix of demand-side and supply-side resources that will meet need under the given set of static assumptions defined in the scenario or sensitivity. This stage helps PSE to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

Deterministic analysis helps to answer the question: How will different resource alternatives dispatch to market given the assumptions that define each of the scenarios and sensitivities? All of PSE's existing resources are modeled, plus all of the generic resource alternatives.

Stochastic Risk Analysis

In this stage of the resource plan analysis, PSE examines how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. Inputs that were static in the deterministic analysis are deliberately varied to create simulations called "draws" used to analyze the different portfolios. This allows PSE to learn how different strategies perform with regard to cost and risk across a wide range of power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

With stochastic risk analysis, PSE tests the robustness of different portfolios; in other words, determine how well the portfolio might perform under a range of different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

2 / To screen some resources, we also use simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

For this purpose, PSE takes some of the portfolios (drawn from the deterministic analysis of scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, gas prices, hydro generation, wind and solar generation, load forecasts (energy and peak), and plant forced outages. This stochastic analysis enables PSE to evaluate the risk associated with the selected portfolios to inform the preferred portfolio.

Customer Benefits Analysis

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. The analysis of the equitable distribution of burdens and benefits into the resource planning process is new in the 2021 IRP. PSE is excited to incorporate these new ideas into the resource planning process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. Below is a brief overview of PSE's first attempt to incorporate customer benefits into the IRP process.

Incorporating the equitable distribution of burdens and benefits into the resource planning process requires a multifaceted approach. Therefore, PSE has developed several tools and methods; these include the Economic, Health and Environmental Benefits (EHEB) Assessment, the Equity Advisory Group (EAG) and the Customer Benefits Analysis.

The EHEB Assessment is an analysis outside of the IRP portfolio modeling process that seeks to determine how benefits and burdens are distributed among PSE customers. The EHEB Assessment provides a snapshot of current conditions across PSE's service area that shows where disparities exist and identifies key constituencies (vulnerable populations and highly impacted communities) which are at greater risk according to a range of customer benefit indicators. Customer benefit indicators are measures that speak to the degree to which specific groups are burdened or benefit from public health, environmental, economic and societal impacts. A full description of the methods and results of the EHEB Assessment are provided in Appendix K.

More directly related to the portfolio development process is the Customer Benefit Analysis. Historically, the IRP selected a preferred portfolio based on cost and reliability alone. CETA legislation has added the consideration of customer benefit indicators to these criteria. Since existing portfolio optimization software lacks the ability to incorporate customer benefit indicators, the Customer Benefit Analysis is performed outside of the portfolio and iterated into the overall portfolio development process. The Customer Benefit Analysis ranks portfolios based on a number of customer benefit indicators. Portfolios with high ranks help to inform key components

3 / Each of the 250 simulations is for the 24-year IRP forecasting period, 2022 through 2045.

that should be incorporated into the preferred portfolio. Preferred portfolio candidates are then incorporated into the ranking process to ensure they provide a suitable balance of customer benefit indicators. It is not enough to score well in one or two customer benefit indicator areas, a good portfolio must provide a range of benefits.

Portfolio outputs were mapped to customer benefit indicators using PSE's best judgement. The customer benefit indicators selected for the Customer Benefit Analysis do not necessarily align directly to the customer benefit indicators used in the EHEB Assessment. This is because of data availability constraints of each analysis. In future IRP cycles, PSE aims to better align customer benefit indicators across all analyses through customer input and insights from the Equity Advisory Group. Figure 8-7 provides an overview of the customer benefit indictors used in the Customer Benefit Analysis.

Figure 8-7: Customer Benefit Indicators for Portfolio Analysis

Area	Customer Benefit Indicator	Definition
Air Quality	Particulate Matter Emissions	Total emissions from thermal resources. Measured in tons.
	SO_2 Emissions	Total emissions from thermal resources. Measured in tons.
	NO_x Emissions	Total emissions from thermal resources. Measured in tons.
Environment	Renewable Generation	Energy generated from utility-scale renewable resources. Measured in MWh.
	Customer Programs	Energy generated from Green Direct, Green Power and Qualifying Resources. Measured in MWh.
	Energy Efficiency	Energy savings from energy efficiency, distribution efficiency and codes and standards. Measured in MWh.
	Distributed Generation	Energy generated from distributed solar (rooftop and ground-mounted), non-wires alternatives and net metering. Measured in MWh.
Economic	Portfolio Cost	Levelized cost of the portfolio. Measured in billions of dollars.
Energy Resiliency	Storage	Capacity of distributed storage added to the portfolio. Measured in MW.

Area	Customer Benefit Indicator	Definition
Climate Change	Social Cost of Greenhouse Gases	Levelized social cost of greenhouse gases. Measured in billions of dollars.
	Greenhouse Gas Emissions	CO_2 equivalent emissions. Measured in tons.
Market Position	Market Purchases	Energy purchased from market. Measured in MWh.
Resource Adequacy	Demand Response	Capacity of demand response programs in the portfolio. Measured in MW.

The customer benefit indicators are measured values from each portfolio analyzed. Measurements may be taken over various intervals along the planning horizon to gain an understanding of how customer benefit indicators evolve over time. For example, greenhouse gas emissions may be measured in the year 2031 to understand climate impacts at the 10-year Clean Energy Action Plan planning horizon as well as in the year 2045 to get a view of climate impacts for the entire IRP period.

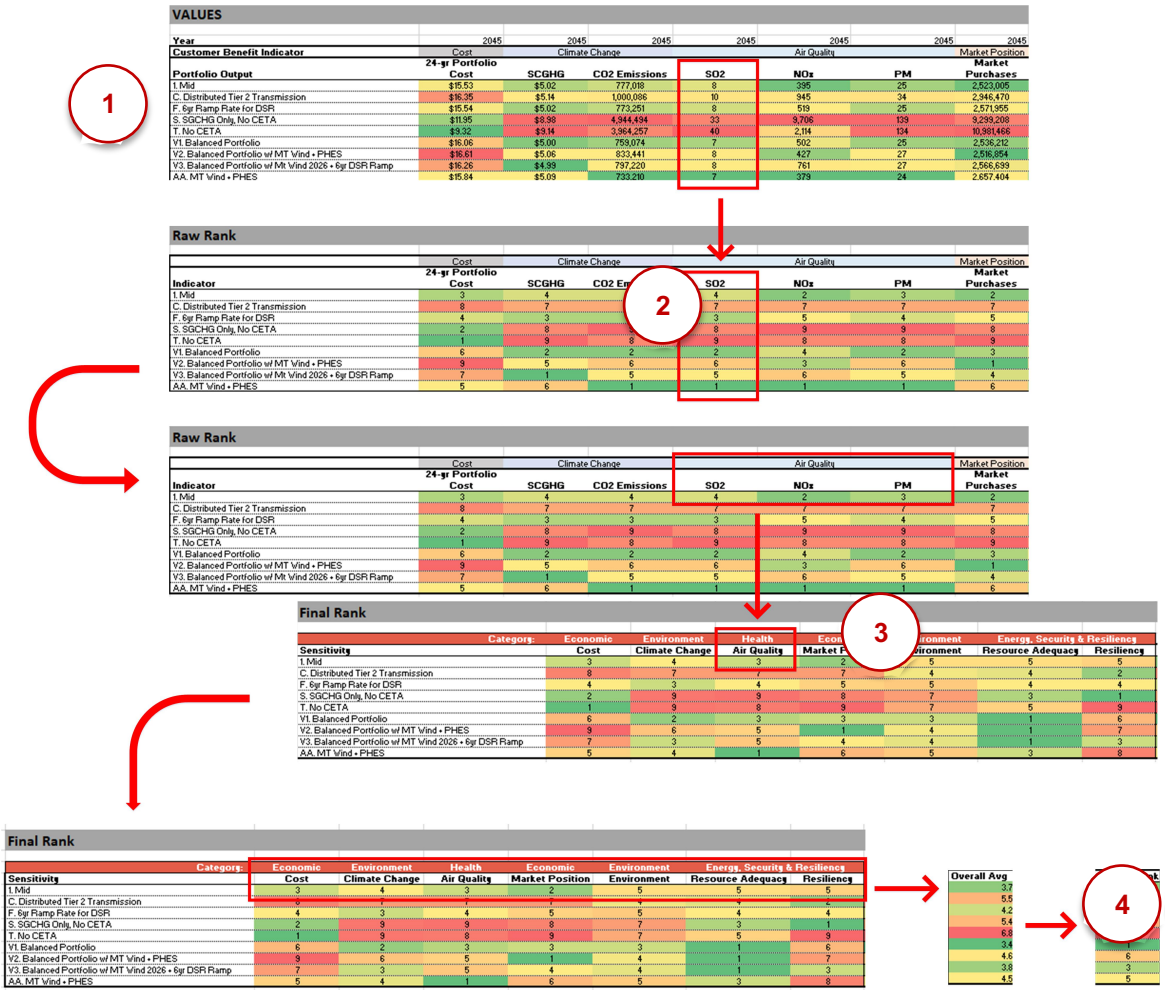
To make meaningful decisions about how different portfolios impact PSE's customers, the relative strengths and weaknesses of the portfolios are compared using the different customer benefit indicators.

The process to compare portfolio tradeoffs is depicted in Figure 8-8:

1. Values for each customer benefit indicator are extracted from the AURORA portfolio model for each portfolio being compared.
2. Values for each customer benefit indicator are ranked; where the most beneficial (or least burdensome) portfolio receives a rank of 1 and the least beneficial (or most burdensome) portfolio receives a rank of 'n', where there are n portfolios compared.
3. Individual customer benefit indicators are aggregated into customer benefit areas to more evenly distribute the benefit of each the various areas. For example, the ranks of SO_2, NO_x and PM are averaged together by portfolio to obtain an air quality rank.
4. Finally, for each portfolio, all the customer benefit indicator area ranks are averaged together to produce an overall average which is then converted to an overall rank.

The portfolio with the rank of 1 would provide the best balance of all customer benefit indicators. Furthermore, specific pieces of information may be used throughout the portfolio development process to help derive a more desirable portfolio. For example, the results for Sensitivity C: Distributed, Tier 2 Transmission Constraints, obtain favorable ranks in the Environment customer benefit indicator area, due to the large amount of energy efficiency and distributed resources in the portfolio. These elements may be incorporated into the preferred portfolio to improve its benefit to the environment.

Figure 8-8: Portfolio Ranking Process



NOTE: Data contained within this figure is draft and intended for demonstration purposes only. The results of the Customer Benefit Analysis is provided later in this chapter and a complete set of customer benefit indicator ranks is provided in Appendix H.

PSE recognizes the customer benefit indicators used in the Final IRP are preliminary and will evolve with time. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process. In particular, two areas of consideration that require further stakeholder input have been identified so far:

- **Qualitative measures:** Although most customer benefit indicators are directly tied to quantitative metrics from the portfolio output, PSE recognizes that some customer benefit indicators may also be qualitative in nature. As qualitative measures are developed, this work may evolve the portfolio customer benefit indicator framework to incorporate indicators which are not directly related to specific portfolio model outputs.

- **Weighting factors:** Additionally, PSE understands some indicators may be more important than others to customers, especially for highly impacted communities and vulnerable populations, and thus require additional collaboration with stakeholders to determine the best weighting to apply across indicators and/or portfolios.

5. KEY FINDINGS

This section summarizes the assumptions for the economic scenarios, portfolio sensitivities and customer benefits indicators developed for this IRP; discusses the key findings from these analyses; and summarizes the optimal portfolio costs and builds produced by the scenario, sensitivity and customer benefits analyses. The following tables are included.

- Figure 8-9: 2021 IRP Electric Portfolio Scenarios and Sensitivities
- Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
- Figure 8-11: Relative Optimal Portfolio Builds by Sensitivity

> > > See Chapter 5, Key Assumptions, for a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible CO_2 prices, resource costs (demand-side and supply-side) and power prices.

> > > See Appendix D, Electric Resource Alternatives, for a detailed discussion of existing electric resources and resource alternatives.

> > > See Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions, for a detailed discussion of the customer indicators developed for the customer benefits analysis.

Summary of Assumptions

Figure 8-9: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast [a.], mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon-free combustion turbines using biodiesel as the fuel.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus reduced access to the Mid-C market for both sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040 (8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources. (energy efficiency, distribution efficiency and demand response)
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

NOTE
a. Mid demand refers to the 2021 IRP Base Demand Forecast.

Key Findings: Economic Scenarios

The quantitative results produced by extensive analytical and statistical evaluation led to the key findings summarized in the following pages.

Economic Scenarios

Portfolio additions are very similar across all three economic scenarios. The amount of resources added increased or decreased based on high and low load forecasts, respectively. Direct emissions are lower with the retirement of Centralia and the removal of Colstrip 3 & 4 in 2025 as part of CETA compliance, and continue trending down throughout the planning horizon. The renewable requirement to meet CETA drives the renewable builds for each scenario.

Key Findings: Portfolio Sensitivities

Future Market Availability

Renewable overgeneration occurs when renewable resources generate more energy than there is demand. Limiting market access, either sales or purchases, increases the cost of CETA implementation by overbuilding battery storage to store the overgeneration of renewable resources instead of selling it to the market. Reducing the reliance on short-term market during peak increases the peak need for new capacity resources or firm resource adequacy qualifying contracts.

Transmission Constraints and Build Limitations

The majority of new renewable resources included in the 2021 IRP are sited outside of PSE's service area. These resources require transmission to deliver power from the generation site to PSE's customers. Transmission is a relatively scarce asset, and there is uncertainty about PSE's ability to procure transmission for the optimal renewable resource mix. Varying the amount of transmission available to regions around PSE's service area measures the impact of these uncertainties.

There is little impact on portfolio build decisions when transmission constraints are modeled to match transmission procurement expectations and timelines (Sensitivity D). This suggests that the generally unconstrained transmission identified for this IRP is a reasonable assumption for the comparative portfolio sensitivity analysis.

However, portfolio build decisions shift when transmission constraints limit resource build to under 3,070 MW outside of PSE's service area (Sensitivity C). More distributed solar resources

located within PSE's service territory are selected and battery storage is increased to help balance generation and demand.

When contracting firm transmission less than the nameplate capacity of resources, site location and fixed transmission costs are important considerations. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due to the significant portion of time that wind resources spend generating at or near nameplate capacity (i.e., rated power).

Conservation Alternatives

Across the conservation alternatives evaluated for this IRP, cost-effective demand-side resources, portfolio costs and build decisions remain relatively stable. Incremental energy savings by bundle vary depending on the conservation alternative driving the bundle selection. Changes in the assumptions for the conservation alternatives pushed more energy savings into lower bundles. In some results, decreased investment in conservation measures is supplemented by increased demand response measures. By changing the ramp rates and discount rate of the bundles, the portfolio moves into lower bundle levels than the Mid portfolio, but still adds a similar or lower amount of conservation as the Mid portfolio. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045.

Demand response and conservation are important resource options in PSE's portfolio, and they are considered load-reducing resources in the calculation of the CETA renewable need. Absent these resources, the portfolio adds more renewable resources, resulting in increased portfolio costs.

Social Cost of Greenhouse Gases (SCGHG) and CO_2 Regulation

Different modeling approaches to incorporating the social cost of greenhouse gases do not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.

Whether modeling SCGHG as a fixed cost planning adder, a dispatch cost in the resource selection or as a dispatch cost in both the resource selection and hourly portfolio run, CETA requirements for renewable resources are the key driver of portfolio resource additions and costs.

Using the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) to calculate upstream emissions increased those emissions for natural gas, but did not change resource builds or retirements compared to utilizing the IPCC's Fourth Assessment Report (AR4).

Applying a Federal CO_2 tax in addition to SCGHG as a fixed-cost planning adder does appear to alter portfolio build decisions, resulting in the addition of fewer thermal resources. Dispatch from thermal plants also declines over time resulting in lower portfolio emissions.

Emissions Reduction

Reducing emissions and even achieving a 100 percent renewable portfolio may be possible with existing technologies, but the cost to do so is high. Large investments in storage to replace thermal resources results in high portfolio costs. Although direct emissions from generating resources are reduced, indirect emissions from market purchases increase because energy purchased from the market is needed to support the storage-heavy portfolios.

Demand Forecast Adjustments

Using alternative temperature data to forecast demand and use in the resource adequacy analysis lowers the demand forecast and the peak capacity need. The lower demand forecast lowers the CETA renewable need. The reduction in peak capacity need results in all future needs being met by new renewable resources and battery energy storage.

On the other hand, fuel switching from gas to electric results in a higher demand forecast and higher CETA renewable need. Resource builds of every resource type increased to support the higher loads.

CETA Costs

CETA requirements drive renewable resource build decisions. Absent CETA requirements, no renewable resources are added to the portfolio except a wind resource towards the end of the planning horizon, which is needed to maintain compliance with RCW 19.285, and more flexible capacity resources are added over time to meet increasing peak capacity need. The cost of the No CETA portfolio is significantly lower than the CETA-compliant portfolios. This is an initial attempt to evaluate the incremental cost of compliance. Portfolio costs stay within the 2 percent annual revenue requirement for the early part of the planning horizon, but increase over time and exceed the 2 percent cost threshold by 2030.

Balanced Portfolio

A forecast of distributed energy resources (DERs) and customer programs ramped in over time helps to spread the revenue requirement throughout the planning horizon. Although DERs have lower peak capacity contributions and increase portfolio costs, there are customer benefits to be gained related to air quality and environment. Significant emission reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. The availability of biodiesel fuel for peaking capacity resources further reduces emissions.

Relative Optimal Portfolio Costs, Builds and Emissions

Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
(dollars in billions, NPV including end effects)

	24-Yr Levelized Costs ($ Billions)			
Portfolio	**Revenue Requirement**	**SCGHG Adder**	**Total**	**Change from Mid**
1 Mid	$15.53	$5.09	$20.62	$0.00
2 Low	$12.08	$4.53	$16.61	($4.01)
3 High	$21.37	$5.74	$27.11	$6.49
A Renewable Overgeneration	$17.11	$4.45	$21.55	$0.93
B Market Reliance	$16.57	$5.19	$21.76	$1.14
C Distributed Transmission	$16.35	$5.21	$21.56	$0.94
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.11	$20.65	$0.03
F 6-Yr DSR Ramp	$15.54	$5.09	$20.62	$0.00
G NEI DSR	$15.24	$5.12	$20.36	($0.26)
H Social Discount DSR	$15.77	$5.16	$20.94	$0.32
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.10	$20.51	($0.11)
J SCGHG Dispatch Cost - LTCE and Hourly Models	$18.45	$4.81	$23.26	$2.64
K AR5 Upstream Emissions	$15.56	$5.14	$20.71	$0.09
L SCGHG Federal CO2 Tax as Fixed Cost	$17.77	$4.71	$22.47	$1.86
M Alternative Fuel for Peakers - Biodiesel	$15.53	$4.99	$20.52	($0.10)
N1 100% Renewable by 2030 Batteries	$32.03	$3.76	$35.79	$15.17
N2 100% Renewable by 2030 PSH	$66.64	$2.52	$69.16	$48.54
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	$28.16	$7.54
O2 100% Renewable by 2045 PSH	$46.95	$3.98	$50.94	$30.32
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.38	$37.22	$16.60
P2 No Thermal Before 2030, PHES	$22.85	$4.77	$27.62	$7.00

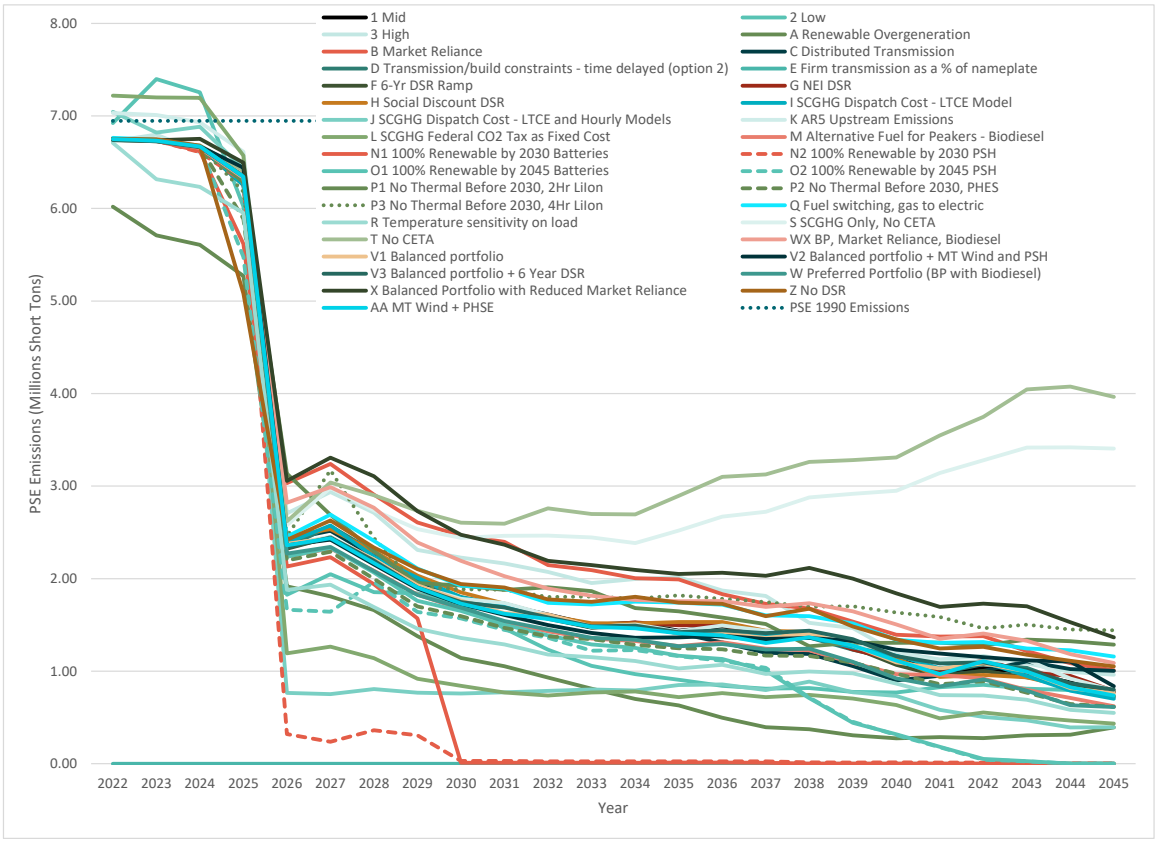
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.69	$45.70	$25.08
Q Fuel switching, gas to electric	$19.56	$5.60	$25.16	$4.54
R Temperature sensitivity on load	$13.53	$4.69	$18.22	($2.40)
S SCGHG Only, No CETA	$9.29	$8.86	$18.16	($2.46)
T No CETA	$9.32	$9.27	$18.59	($2.03)
V1 Balanced portfolio	$16.06	$5.07	$21.14	$0.52
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.12	$21.73	$1.11
V3 Balanced portfolio + 6 Year DSR	$16.26	$5.06	$21.32	$0.70
W Preferred Portfolio (BP with Biodiesel)	$16.10	$4.96	$21.06	$0.44
X Balanced Portfolio with Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95
WX BP, Market Reliance, Biodiesel	$17.30	$5.06	$22.36	$1.74
Z No DSR	$17.54	$5.56	$23.10	$2.48
AA MT Wind + PHSE	$15.84	$5.16	$20.99	$0.37

Figure 8-11: Relative Optimal Portfolio Builds by Scenario and Sensitivity
(cumulative nameplate capacity in MW for each resource addition by 2045)

	Resource Additions by 2045, Nameplate (MW)											
Portfolio	**Demand-side Resources**	**Battery Energy Storage**	**Solar - Ground and Rooftop**	**Demand Response**	**DSP Non-Wire Alternatives**	**Biomass**	**Solar**	**Wind**	**Renewable + Storage Hybrid**	**Pump Hydro Storage**	**Peaking Capacity**	**Total**
1 Mid	1,497	550	0	123	118	90	1,393	3,350	250	0	948	**8,319**
2 Low	1,537	275	0	181	118	30	1,096	2,450	250	0	237	**6,175**
3 High	1,733	900	0	128	118	150	2,292	3,850	0	0	1,659	**10,830**
A Renewable Overgeneration	1,537	1,525	0	192	118	150	2,388	2,250	725	0	474	**9,359**
B Market Reliance	1,497	650	50	173	118	135	995	3,350	375	0	1,732	**9,075**
C Distributed Transmission	1,537	1,050	2,700	178	118	150	500	2,615	125	0	1,003	**9,976**
D Transmission/ build constraints - time delayed (option 2)	1,537	650	0	180	118	135	1,295	3,300	250	0	948	**8,413**
F 6-Yr DSR Ramp	1,372	625	0	175	118	150	1,394	3,150	500	0	966	**8,449**
G NEI DSR	1,304	450	0	188	118	150	1,393	3,450	125	0	1,185	**8,363**
H Social Discount DSR	1,179	675	0	195	118	150	1,391	3,150	625	0	948	**8,431**
I SCGHG Dispatch Cost - LTCE Model	1,497	875	0	188	118	135	1,294	3,150	375	0	766	**8,398**
J SCGHG Dispatch Cost - LTCE and Hourly Models	1,497	850	0	205	118	60	996	3,550	375	0	747	**8,397**
K AR5 Upstream Emissions	1,497	625	0	140	118	150	1,393	3,150	250	0	948	**8,270**
L SCGHG Federal CO2 Tax as Fixed Cost	1,537	525	0	183	118	135	1,395	3,150	250	0	829	**8,122**
M Alternative Fuel for Peakers - Biodiesel	1,537	700	0	185	118	75	1,593	3,150	250	0	948	**8,557**
N1 100% Renewable by 2030 Batteries	1,304	26,200	0	59	118	0	1,994	3,850	0	0	0	**33,523**
N2 100% Renewable by 2030 PSH	1,169	0	0	59	118	75	3,268	3,600	622	21,300	0	**30,211**
O1 100% Renewable by 2045 Batteries	1,304	24,500	0	128	118	0	1,692	3,950	0	0	0	**31,692**

O2 100% Renewable by 2045 PSH	1,537	0	0	204	118	0	99	3,650	1,249	19,600	0	**26,458**
P1 No Thermal Before 2030, 2Hr LiIon	1,372	4,300	0	178	118	15	1,695	3,550	125	0	474	**11,827**
P2 No Thermal Before 2030, PHES	1,304	1,025	0	122	118	15	2,294	3,550	0	2,700	18	**11,146**
P3 No Thermal Before 2030, 4Hr LiIon	1,372	4,425	0	129	118	0	2,292	3,250	0	0	0	**11,586**
Q Fuel switching, gas to electric	1,537	2,000	0	108	118	135	4,880	3,850	825	0	2,961	**16,414**
R Temperature sensitivity on load	1,372	500	0	130	118	150	1,195	3,150	0	0	0	**6,614**
S SCGHG Only, No CETA	1,179	50	0	203	118	0	0	350	0	0	1,896	**3,795**
T No CETA	1,042	0	0	123	118	0	0	350	0	0	2,133	**3,766**
V1 Balanced portfolio	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,641**
V2 Balanced portfolio + MT Wind and PSH	1,784	375	680	217	118	120	895	3,150	425	0	948	**8,711**
V3 Balanced portfolio + 6 Year DSR	1,658	675	680	217	118	120	895	3,450	125	0	1,003	**8,940**
W Preferred Portfolio (BP with Biodiesel)	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,354**
X Balanced Portfolio with Reduced Market Reliance	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,321**
WX BP, Market Reliance, Biodiesel	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,607**
Z No DSR	690	1,250	0	0	118	150	2,688	3,450	500	0	1,422	**10,268**
AA MT Wind + PHSE	1,497	300	0	182	118	150	1,094	3,350	425	0	948	**8,064**

Figure 8-12: Relative Optimal Portfolio Emissions by Scenario and Sensitivity (annual direct portfolio emissions by year)



6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar and the amount of resources added varied depending on the load forecasts. In the Low economic scenario fewer resources are added due to lower demand, lower peak need and lower renewable need. In the High economic scenario, more resources are added due to higher demand, higher peak need and higher renewable need. Figure 8-13, shows the levelized cost by scenario while Figure 8-14 shows the optimal portfolio builds by scenario.

Figure 8-13: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

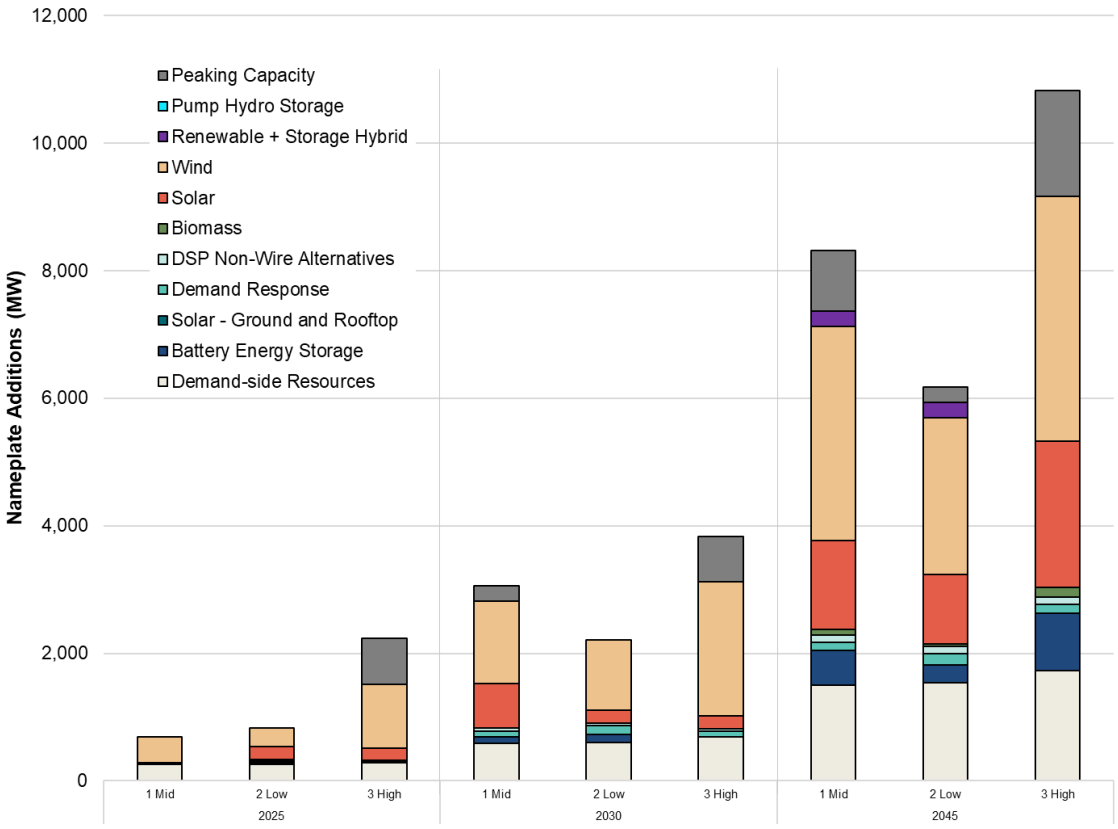
		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
2	Low Scenario	$12.08	$4.53	$16.61	($3.45)
3	High Scenario	$21.37	$5.74	$27.11	$5.84

Figure 8-14: Relative Optimal Portfolio Builds by Scenario
(cumulative nameplate capacity in MW for each resource addition by 2045)

Resource Additions by 2045	1 Mid	2 Low	3 High
Demand-side Resources	1,497 MW	1,537 MW	1,733 MW
Battery Energy Storage	550 MW	275 MW	900 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	181 MW	128 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	3,576 MW	6,292 MW
Biomass	90 MW	30 MW	150 MW
Solar	1,393 MW	1,096 MW	2,292 MW
Wind	3,350 MW	2,450 MW	3,850 MW
Renewable + Storage Hybrid	250 MW	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	237 MW	1,659 MW

Figure 8-15 below displays the megawatt additions for the deterministic analysis of optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix H, Electric Analysis Inputs and Results, for more detailed information.

Figure 8-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

Figure 8-16 shows CO_2 emissions for the Mid, Low and High Scenarios. The chart shows the direct emissions from portfolio resources for each scenario and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Despite varying demand, natural gas price and electric price forecasts, the three scenarios all converge on a similar quantity of direct emissions by 2045, driven by CETA renewable energy targets.

Figure 8-16: CO_2 Emissions for the Mid, Low and High Scenarios
(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

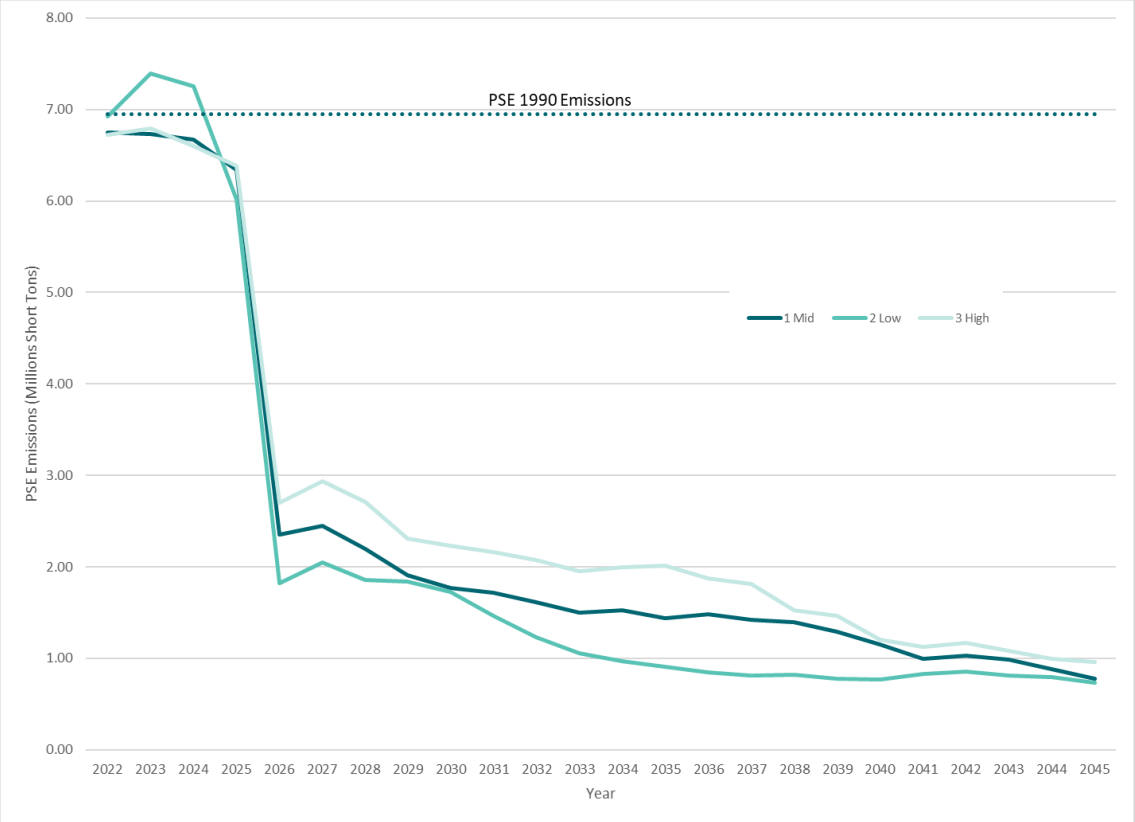
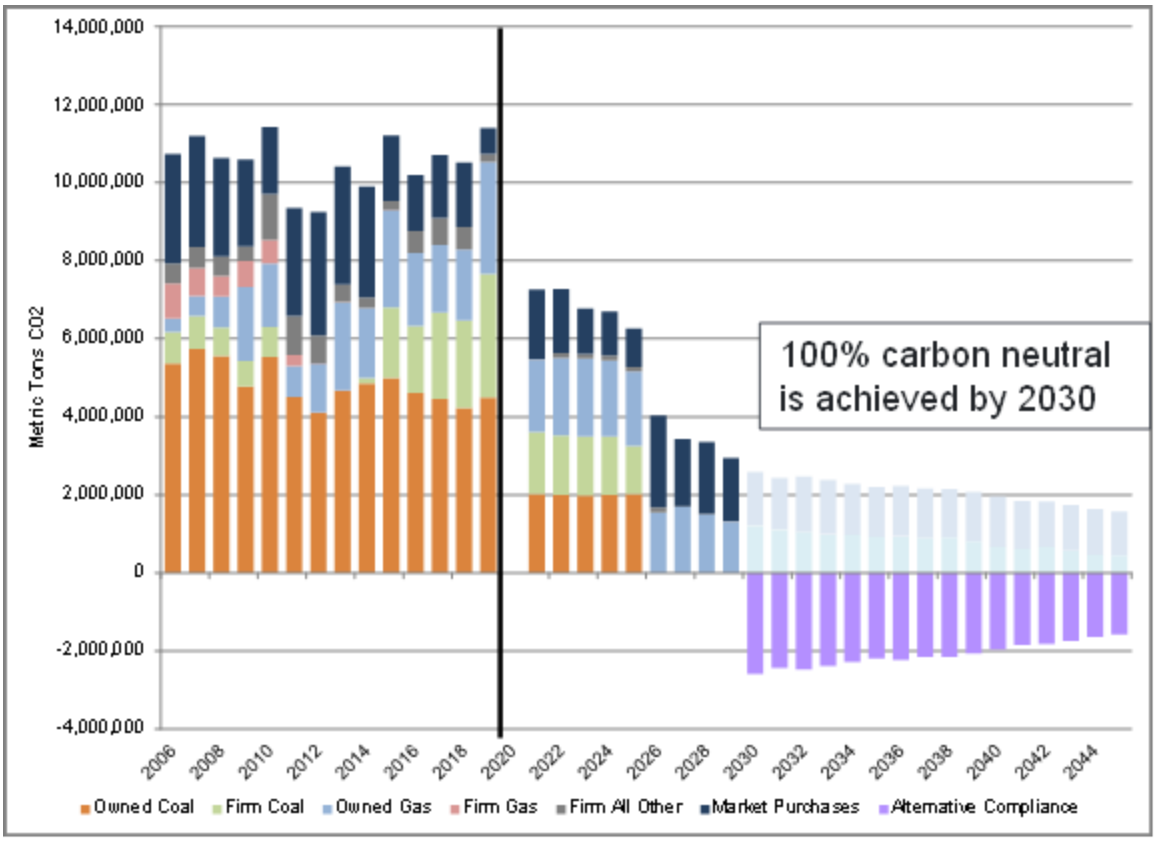


Figure 8-17, below, shows the Mid Scenario portfolio emissions by resource type. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will decrease further with a lower projected economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from the portfolio. With the resource retirements and forecasted drop in dispatch, total portfolio emissions decrease by over 70 percent from 2019 to 2029. Using alternative compliance mechanisms, the portfolio achieves carbon neutrality from 2030 through to 2045.

Figure 8-17: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



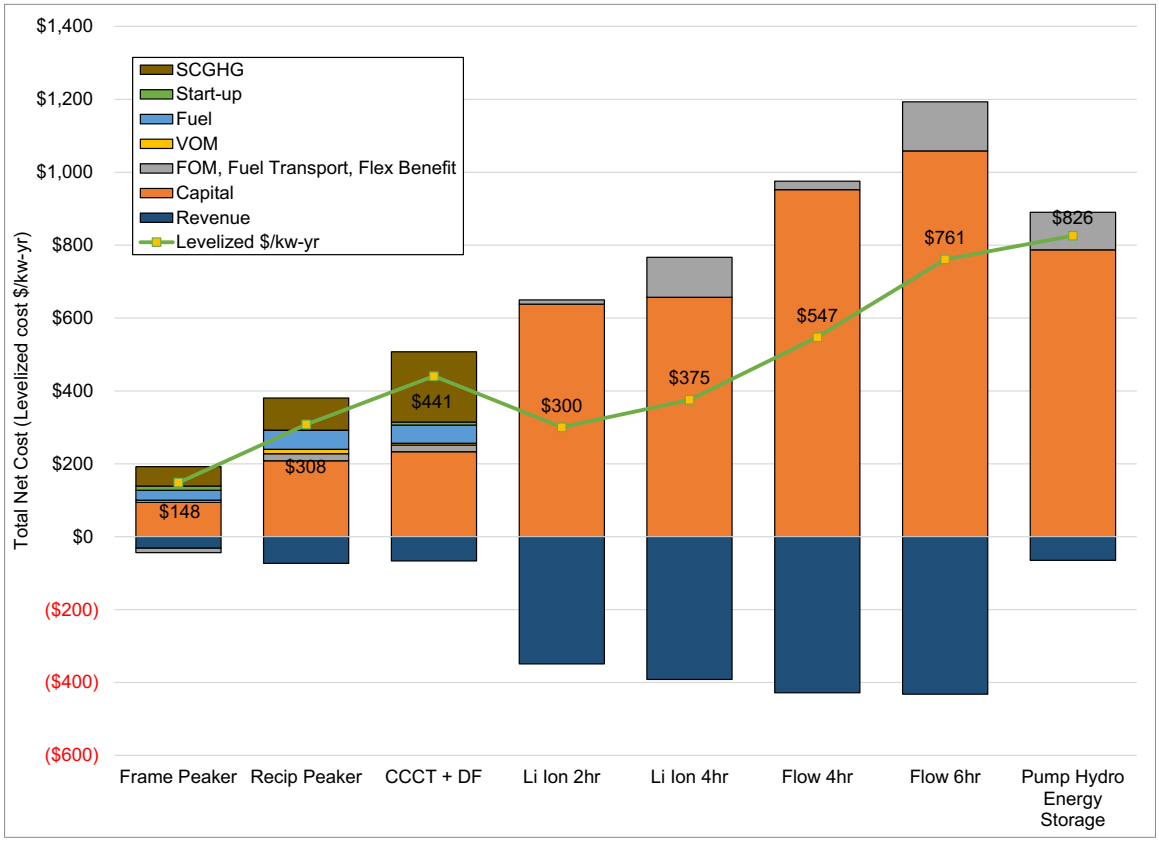
Levelized Cost of Capacity

The levelized costs for peakers, baseload natural gas plants and energy storage resources were evaluated using the Mid Scenario assumptions for electric price, natural gas price and demand to better understand how the resources compare during resource selection. The levelized cost of capacity is based on the peak capacity value of a resource. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC[4] of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW, which is why it has a high levelized cost of capacity.) When calculating the levelized cost of capacity for new peakers and baseload natural gas plants, the SCGHG is added to the total cost; this increased the levelized cost of capacity for frame peakers from $95 to $148. Figure 8-18

4 / The effective load carrying capacity (ELCC) of a resource represents the peak capacity credit assigned to that resource. More information on ELCC can be found in Chapter 7.

compares the net cost of capacity for peakers, baseload natural gas plants and energy storage resources.

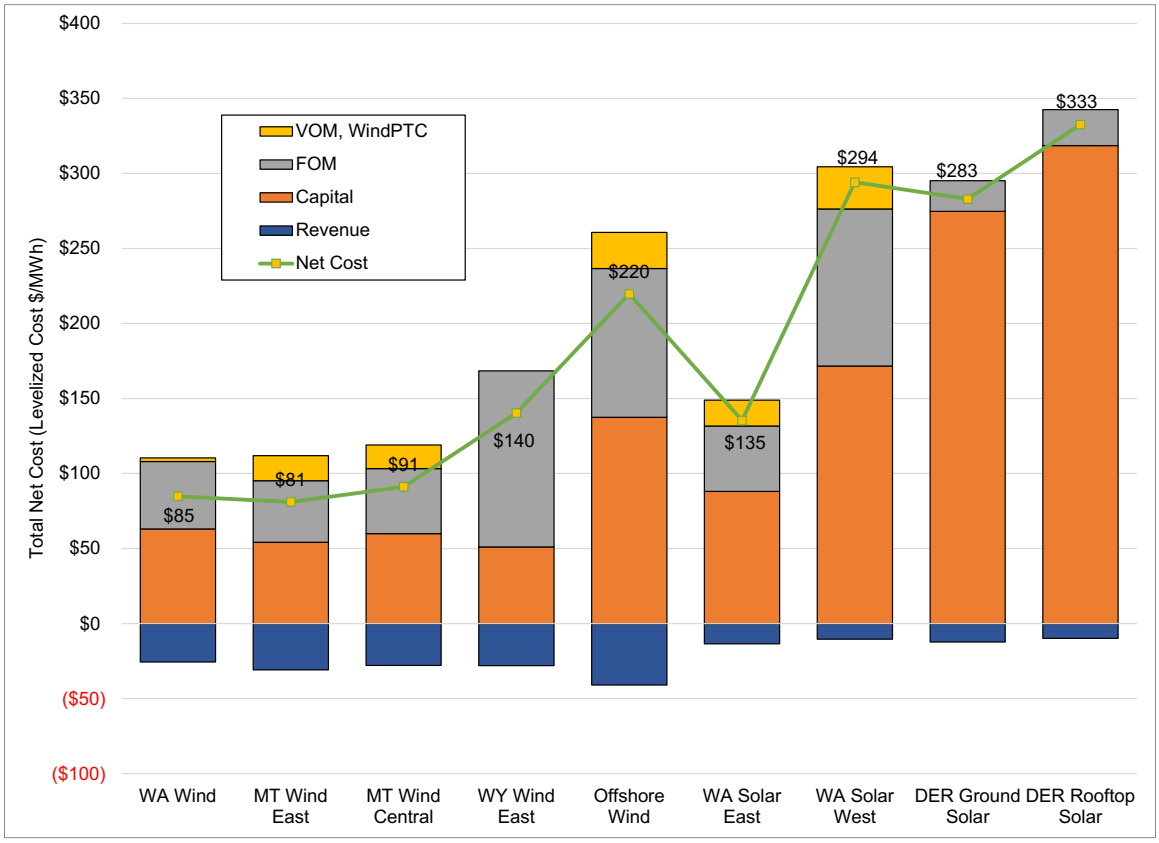
Figure 8-18: Net Cost of Capacity in the Mid Scenario Portfolio Model



Levelized Cost of Energy

The levelized costs of energy for wind and solar resources were also evaluated using the Mid Scenario assumptions to better understand how the resources compare during resource selection. The costs are calculated based on energy and do not account for any peak capacity contribution. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Even though Wyoming wind is higher cost because of transmission costs, it has a high peak capacity credit and provides other value to the portfolio. Given transmission constraints, resources outside of the Pacific Northwest region will be limited. After Montana and Wyoming wind, eastern Washington utility-scale solar is the next lowest cost resource. Figure 8-19 illustrates the levelized costs of renewable resource to meet CETA.

Figure 8-19: Wind and Solar Cost Components, Mid Scenario Portfolio



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis that helps PSE understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. This section provides the results and detailed analysis for each sensitivity. Additional results, including year-by-year resource timelines, cost breakdowns and emissions data are provided in Appendix H.

Future Market Availability

A. Renewable Overgeneration Test

In the Mid portfolio there were 0.23 percent of load (355 hours) of overgeneration in 2030 and 10 percent of load (4,000 hours) in 2045. This sensitivity tests the costs and portfolio changes to eliminate the overbuild of renewable generation observed in the Mid portfolio. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales to reduce cost of meeting CETA.

Baseline: PSE can sell 1,500 MW of energy to the Mid-C market at any given hour, subject only to transmission availability.
Sensitivity > PSE cannot sell any energy to the Mid-C market.

KEY FINDINGS. Prohibiting sales to the Mid-C market reduces renewable overgeneration by eliminating market sales and increasing battery energy storage so that the generation can be stored instead. Though renewable generation still occurs in Sensitivity A, it is reduced by 10 percent consistent with the 10 percent overbuild of generation in the Mid Scenario. Wind capacity is reduced, and the remaining renewable generation is from increased solar builds. This portfolio costs almost $1.6 billion more than the Mid portfolio by adding more battery energy storage, but only reduced the overgeneration by 3 percent by 2045. Figure 8-20 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A portfolios. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. In Sensitivity A, without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources; once the battery resources are at capacity, there is no option left but to curtail the energy. The market is an effective way to reducing cost.

Figure 8-20: Renewable Overgeneration – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	355	53,946	0.23%	4,330	3,021,777	10.6%
Sensitivity A	29	1,495	0.01%	3,396	2,063,604	7.21%

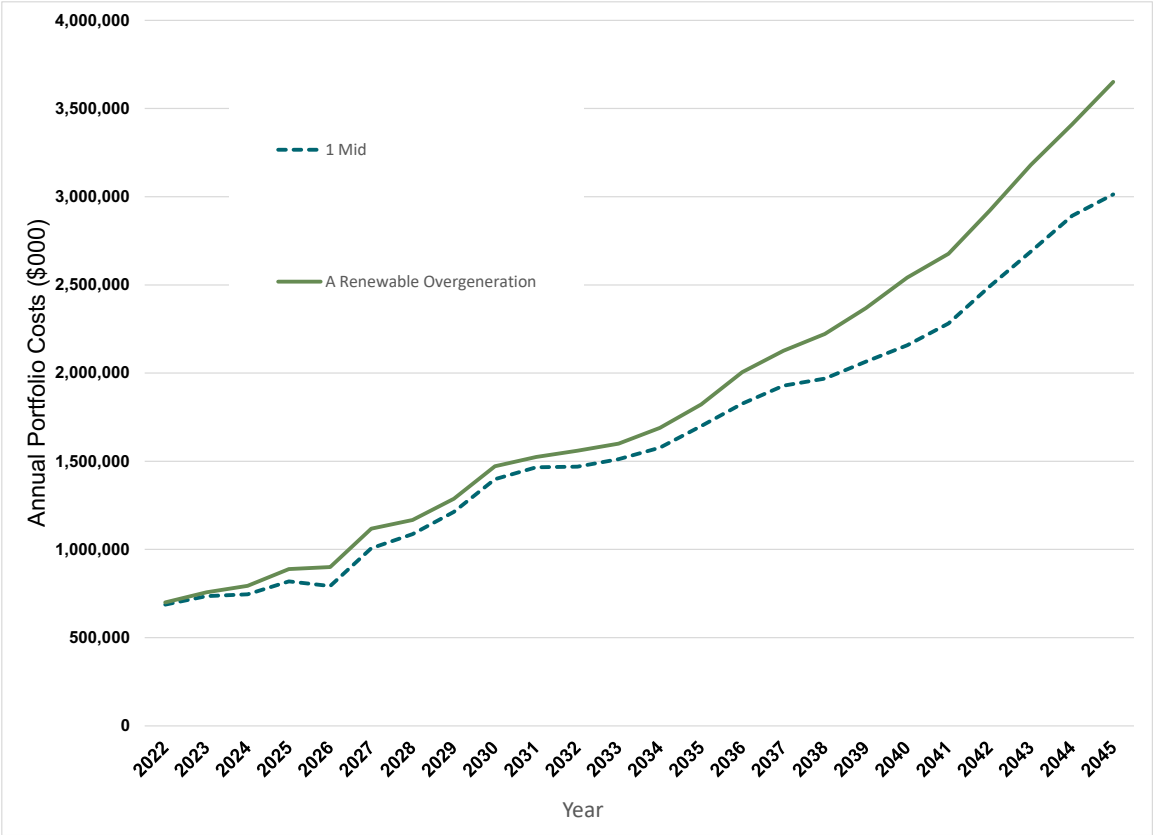
ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid portfolio. The only difference between Sensitivity A and the Mid Scenario is PSE's ability to sell energy to the Mid-C market, which is removed in Sensitivity A.

ANNUAL PORTFOLIO COSTS. Figures 8-21 and 8-22 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. Sensitivity A is higher cost overall than the Mid portfolio, and costs begin to diverge at a greater pace as sensitivity A invests heavily in the energy storage necessary to store the renewable generation that cannot be sold to the market. .

Figure 8-21: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
A	Renewable Overgeneration test	$17.11	$4.45	$21.55	$0.93

Figure 8-22: Annual Portfolio Costs – Mid Scenario and Sensitivity A



RESOURCE ADDITIONS. Figure 8-23 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds more nameplate capacity than the Mid Scenario, and the distribution of resources shifts some capacity from wind generation to solar and storage. No pumped hydro storage is built, but investment in hybrid resources and standalone battery resources increases. Conservation reaches Bundle 11 in this sensitivity. No PSE resources, new or existing, are retired in this sensitivity.

Figure 8-23: Portfolio Additions– Mid Scenario and Sensitivity A, Renewable Overgeneration

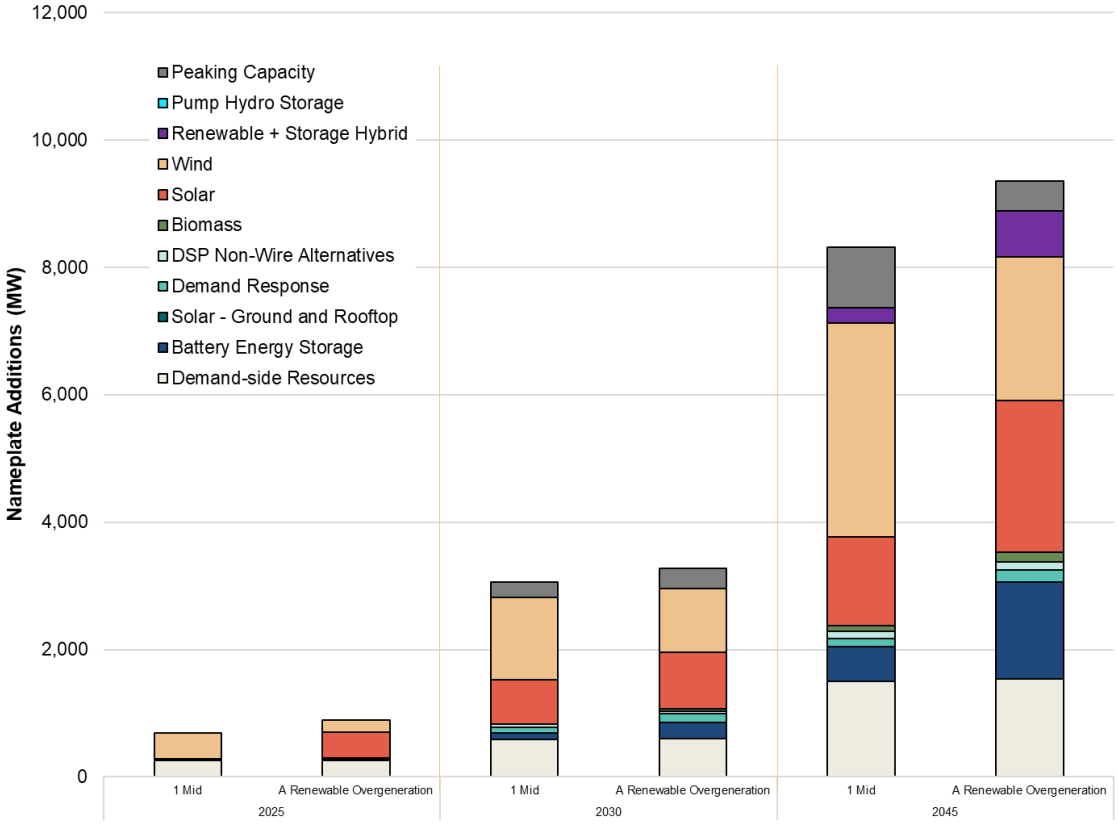


Figure 8-24: Portfolio Additions by 2045 – Mid Scenario and Sensitivity A, Renewable Overgeneration

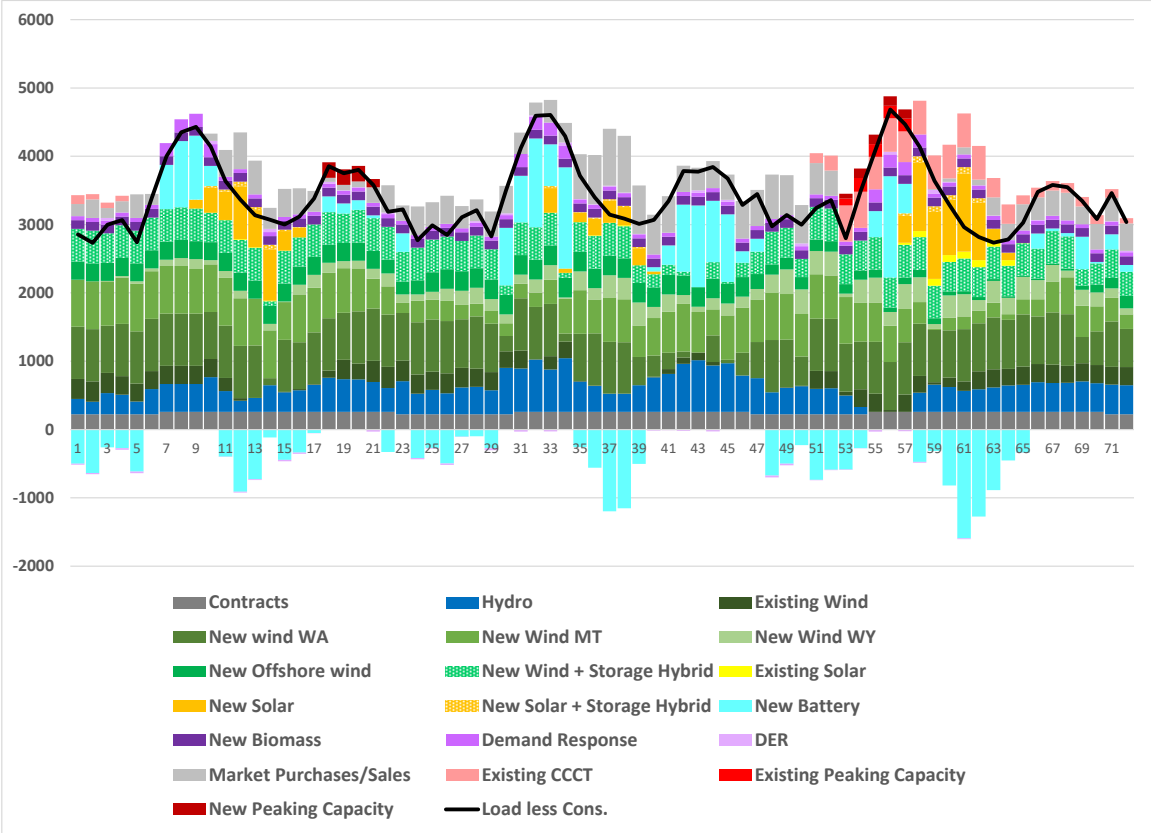
Resource Additions by 2045	1 Mid	A Renewable Overgeneration
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	192 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,788 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,388 MW
Wind	3,350 MW	2,250 MW
Renewable + Storage Hybrid	250 MW	725 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW[1]

NOTE
1. Includes 237 MW of recip peakers and 237 MW of frame peakers

PEAK NEED. In 2045, the peak capacity behavior of the new resources changes in this sensitivity. Figure 8-25 shows the hourly dispatch of resources in Sensitivity A during peak demand for 2045. Resources generating above the black line are producing power in excess of load from mostly market purchases (gray bars) and some new and existing natural gas generation (maroon and pink bars) mostly to charge batteries (blue bars below zero).

During periods of peak demand, there is not enough generation to both meet customer demand and charge batteries. In order for the battery to meet energy need during peaks, the batteries must be charged. Without market for charging the batteries as in this sensitivity, the model uses natural gas generation to charge the batteries.

Figure 8-25: 2045 Peak Demand Period of Sensitivity A, December 28-30, 2045



The relationship between market purchases and battery activity can be seen by examining the times at which the market purchases are occurring. For Sensitivity A, Figure 8-26 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045. Market purchases are made consistently throughout the winter to assist the generating resources. During off-peak hours, market purchases provide energy for the batteries to charge; during peak hours when the batteries are discharging, market purchases help to meet demand.

Figure 8-26: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A, 2045

All Purchase Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	81%	83%	87%	27%	0%	0%	13%	48%	83%	71%	67%	100%
1:00	81%	83%	84%	27%	0%	0%	13%	48%	90%	71%	67%	100%
2:00	81%	86%	84%	27%	0%	0%	13%	48%	83%	71%	67%	100%
3:00	81%	83%	81%	23%	0%	0%	13%	42%	83%	71%	67%	100%
4:00	81%	86%	77%	17%	0%	0%	10%	48%	83%	74%	63%	87%
5:00	84%	76%	77%	20%	0%	0%	6%	42%	87%	71%	63%	87%
6:00	84%	62%	61%	17%	0%	0%	3%	52%	83%	71%	67%	81%
7:00	81%	69%	65%	3%	0%	0%	10%	48%	73%	68%	60%	77%
8:00	84%	79%	58%	10%	0%	0%	6%	61%	70%	71%	60%	87%
9:00	84%	76%	68%	10%	0%	0%	6%	65%	70%	68%	57%	94%
10:00	81%	79%	71%	10%	0%	0%	13%	61%	67%	68%	57%	97%
11:00	77%	79%	68%	10%	0%	0%	19%	61%	70%	68%	60%	97%
12:00	77%	79%	65%	17%	0%	0%	19%	65%	70%	68%	60%	97%
13:00	77%	79%	71%	13%	3%	0%	23%	58%	70%	68%	60%	97%
14:00	81%	79%	71%	7%	3%	0%	10%	58%	70%	65%	63%	97%
15:00	81%	79%	71%	10%	3%	3%	13%	52%	70%	68%	67%	97%
16:00	84%	79%	61%	3%	0%	0%	0%	48%	70%	71%	73%	97%
17:00	84%	76%	68%	10%	3%	0%	3%	23%	63%	71%	70%	97%
18:00	84%	76%	68%	17%	3%	3%	19%	39%	60%	74%	73%	94%
19:00	84%	83%	68%	17%	6%	3%	26%	32%	63%	74%	70%	94%
20:00	87%	76%	71%	17%	6%	3%	23%	39%	73%	81%	67%	97%
21:00	84%	79%	77%	17%	6%	7%	26%	52%	90%	77%	73%	97%
22:00	81%	83%	77%	17%	6%	7%	19%	45%	93%	74%	73%	97%
23:00	81%	83%	77%	17%	6%	3%	19%	45%	90%	77%	73%	97%

B. Reduced Market Reliance

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy

model. Sensitivity B provides insight into navigating a market with reduced availability of market purchases by examining how to optimize a portfolio that is limited by these conditions.

Baseline: PSE can make market purchases at the hourly power price, subject to the transmission limits to the Mid-C Market. PSE currently uses these purchases to meet demand at peak demand hours.

Sensitivity B > PSE's transmission access to the Mid-C Market is reduced to 1,300 MW in 2023, 1,100 MW in 2024, 900 MW in 2025, 700 MW in 2026, and 500 MW in 2027 and thereafter during November-February and June-August. Transmission access remains the same for the months March-May and September-October, as well as the year 2022.

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KEY FINDINGS. To compensate for reduced market purchases, sensitivity B overbuilds renewable resources to charge batteries and builds 1,495 of peaking capacity by 2031, nearly double the amount in the Mid Scenario. This sensitivity builds the same amount of Washington wind as the Mid Scenario, but on an accelerated timeline. By 2045, increased storage builds play a larger role in meeting peak demand. Peaking capacity and CCCT thermal generation continue to assist in meeting peak demand, but renewable overgeneration is the primary energy source for batteries.

ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid Scenario portfolio, except for changes to Mid-C market access. The amount of Mid-C Market transmission access in Sensitivity B, which defines the amount of market purchases PSE can make, is seen in Figure 8-27.

Figure 8-27: Transmission Limits to the Mid-C Market in Sensitivity B in MW

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

ANNUAL PORTFOLIO COSTS. Figures 8-28 and 8-29 illustrate the breakdown of costs between the Mid Scenario and Sensitivities B. As expected, increasing restrictions to market purchases increases portfolio costs. This sensitivity builds more resources in the early years of the simulation so the annual portfolio costs start diverging as early as 2023.

The final builds of the Sensitivity B and the Mid Scenario portfolios are similar, with more peaking capacity and an accelerated installation of Washington wind in Sensitivity B. As a result, the annual costs of Sensitivity B track with the costs of the Mid Scenario, with the earlier installation timeline and increased peaking capacity raising the overall price.

Figure 8-28: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity B

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
B	Reduced Market Reliance	$16.57	$5.19	$21.76	$1.35

Figure 8-29: Annual Portfolio Costs – Mid Scenario and Sensitivity B



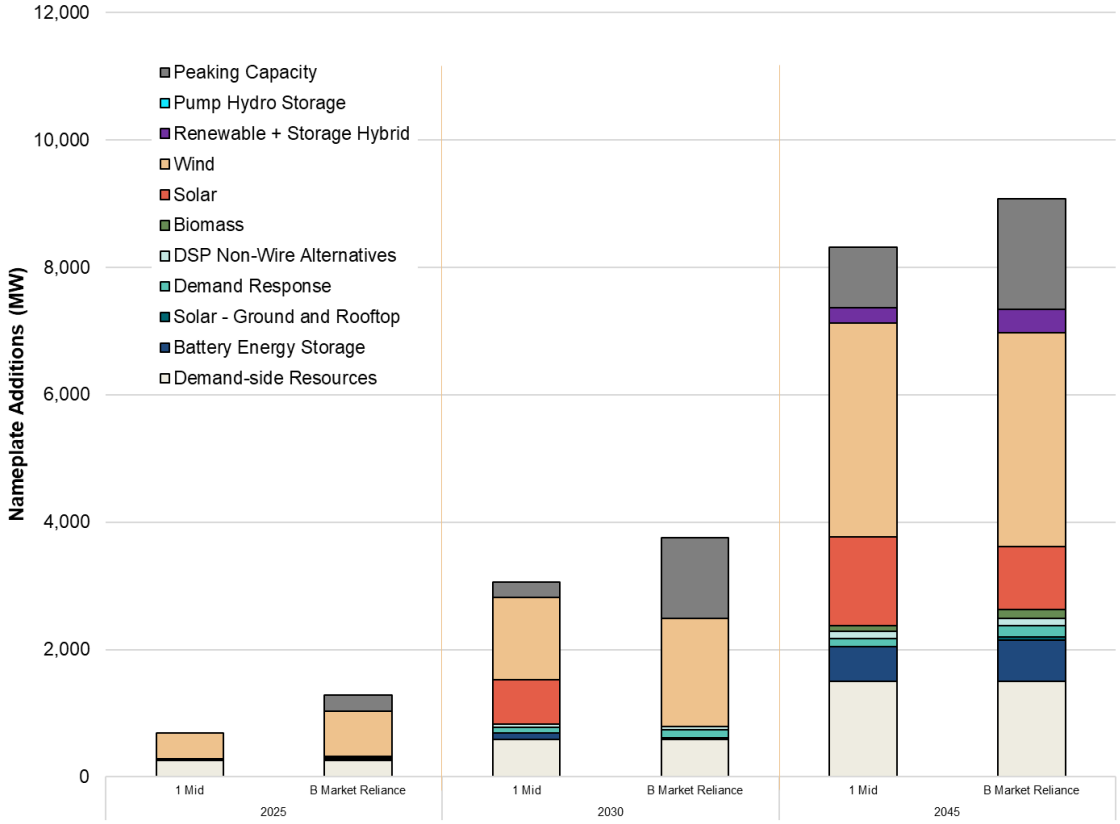
RESOURCE ADDITIONS. Figure 8-30 compares the nameplate capacity additions of the Mid Scenario and Sensitivity B.

Sensitivity B invests in the same amount of demand-side resources as the Mid Scenario (Bundle 10). With limited access to the market, this sensitivity invests heavily in peaking capacity and accelerates the construction of Washington wind resources compared to the Mid Scenario. In the later years of the simulation, storage resources are still needed, but they are delayed due to the high capacity of thermal resources being installed in the early years. Without market purchases to bridge the gap between renewable generation and demand, the portfolio leans heavily on increased peaking capacity builds. Increased peaking capacity is the most prominent difference between the Mid Scenario and Sensitivity B, indicating that the model selects thermal generation as the least cost resource to replace the market purchases. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict.

Figure 8-30: Portfolio Additions – Mid Scenario and Sensitivity B, Reduced Market Reliance

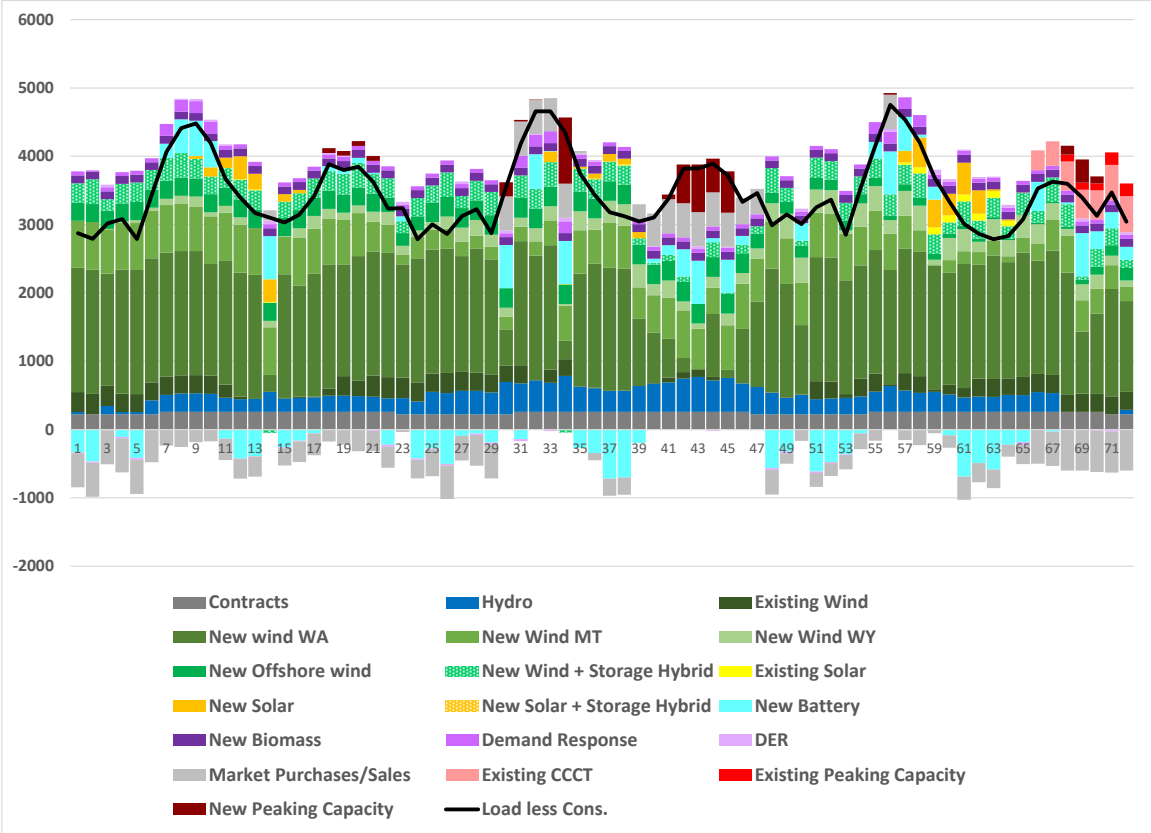
Resource Additions by 2045	1 Mid	B Reduced Market Reliance
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	650 MW
Solar – Ground and Rooftop	0 MW	50 MW
Demand Response	123 MW	173 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,480 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	995 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,732 MW

Figure 8-31: Portfolio Additions by 2045 – Mid Scenario and Sensitivity B, Reduced Market Reliance



PEAK NEED AND EMISSIONS. The peak demand period of Sensitivity B is shown in Figure 8-32. Portfolio B uses renewable overbuilds as the main method of charging the batteries (blue bars). The excess energy, generation above the black lines, provides value through market sales (gray bars below zero) and the charging of batteries (blue bars below zero) during off-peak hours. Market purchases are still available in a limited capacity, and are still used to assist in meeting demand when renewable generation is not sufficient. Thermal generation also continues to play a role in meeting peak demand. In Figure 8-32, thermal generation is still needed when there is not enough energy from renewable resources, batteries, or demand response to meet demand as can be seen in the hours 30, 34, 40-45, and 68-72.

Figure 8-32: 2045 Peak Demand Period of Sensitivity B, December 28-30, 2045



EMISSIONS. Use of thermal generation to compensate for the reduction of market purchases increases the emissions of PSE resources in sensitivity B. Figure 8-33 compares the yearly emissions of PSE resources (without market purchases) to the Mid Scenario.

Figure 8-33: Annual Emissions of PSE Resources – Mid Scenario and Sensitivity B (market purchases are not included)



Transmission Constraints and Build Limitations

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

Baseline: The Mid Scenario assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a maximum of 1,500 MW of Mid-C market access and build limitations for Montana, Idaho and Wyoming based resources. **Sensitivity >** Sensitivity C assumes the more restrictive transmission constraints described by Tier 2, which includes those described in the baseline plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. Tier 2 transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon compared to the Mid Scenario portfolio. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. Sensitivity C pairs the distributed solar resources with battery storage projects to better serve load when solar generation is not available. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

ASSUMPTIONS. Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-34 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-34: Sensitivity C Transmission Constraints – Tier 2

Resource Group Region	Tier 2
PSE territory	unconstrained
Eastern Washington	675
Central Washington	625
Western Washington	100
Southern Washington/Gorge	705
Montana	565
Idaho / Wyoming	400
TOTAL	**3,070**

Several additional constraints were incorporated into the optimization to encourage realistic resource selections. The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar and matches the Conservation Potential Assessment Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E. This assumption aligns with a portfolio focused on distributed energy resources.

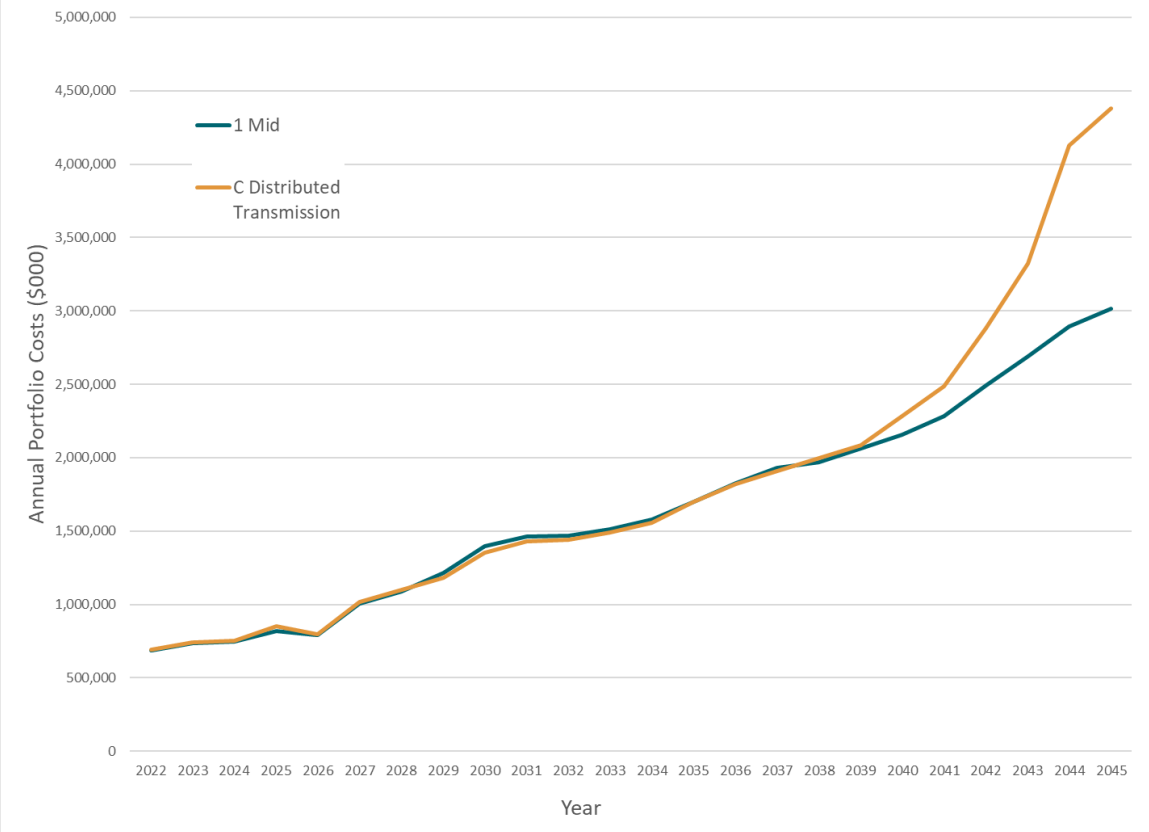
PORTFOLIO COSTS. Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-35. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements. These increased generic resource revenue requirements are the major driver of the increased portfolio cost.

Figure 8-35: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
C	Distributed – Transmission/Build Constraints Tier 2	$16.35	$5.21	$21.56	$0.94

Until year 2039, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-36. After year 2039, Sensitivity C exhausts all available transmission outside of PSE's service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity C



RESOURCE ADDITIONS. Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within the PSE service territory are also added to help accommodate base loads and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario.

Sensitivity C selects conservation Bundle 11 which is more conservation than selected in the Mid Scenario (Bundle 10). The increased conservation is due to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-37 and 8-38.

Figure 8-37: Portfolio Additions – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

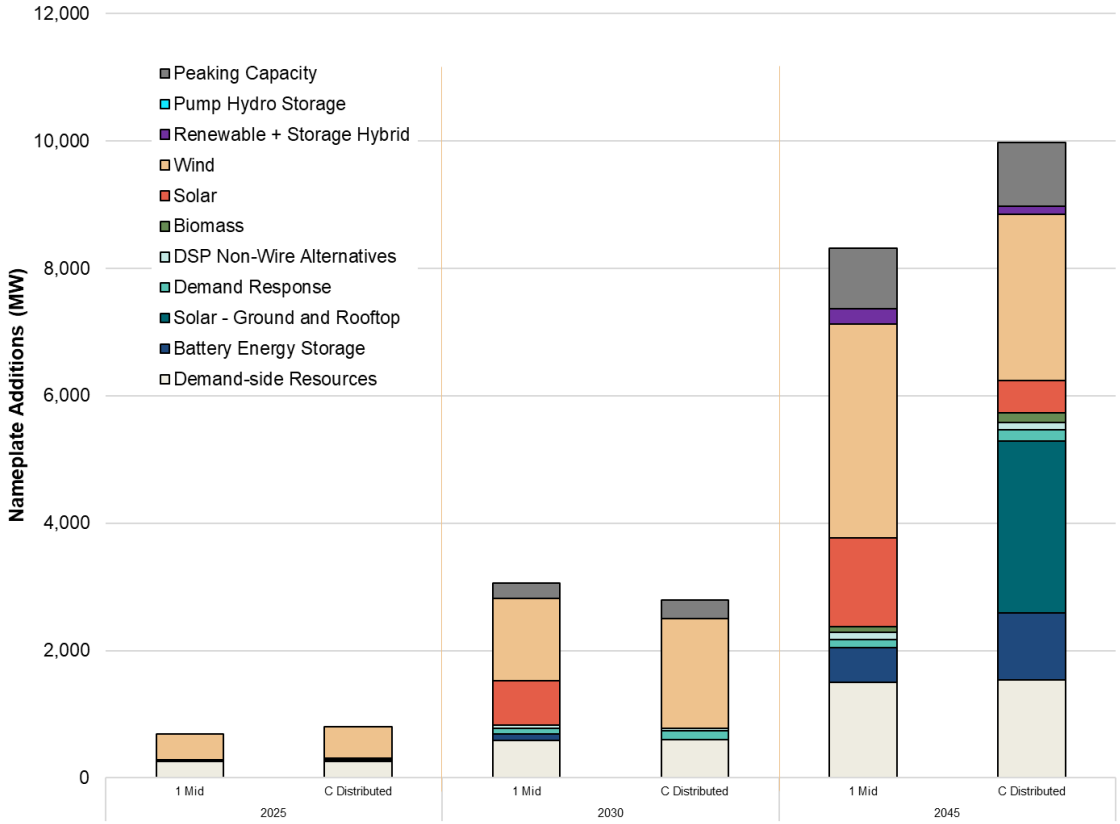


Figure 8-38: Portfolio Additions by 2045 – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

Resource Additions by 2045	1 Mid	C Distributed Transmission Tier 2
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,050 MW
Solar - Ground and Rooftop	0 MW	2,700 MW
Demand Response	123 MW	178 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	3,265 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	500 MW
Wind	3,350 MW	2,615 MW
Renewable + Storage Hybrid	250 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,003 MW

OTHER FINDINGS. Distributed solar, ground mount and rooftop, is capable of meeting a significant portion of load. As shown in Figure 8-39, distributed solar contributes approximately 13 percent of total energy load in 2045. However, distributed solar is a poor resource for meeting peak capacity need, because it has an effective load carrying capability of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need, so slightly more peaking resource capacity was added to Sensitivity C compared to the Mid Scenario portfolio. Furthermore, those peaking capacity resources were dispatched more often, resulting in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.78 million tons of greenhouse gases (GHGs), while Sensitivity C generated 1.00 million tons of GHGs. Figure 8-40 compares the emissions from the Mid Scenario and Sensitivity C portfolios in millions short tons.

Figure 8-39: Annual Energy Production by Resource Type (aggregated) – Sensitivity C

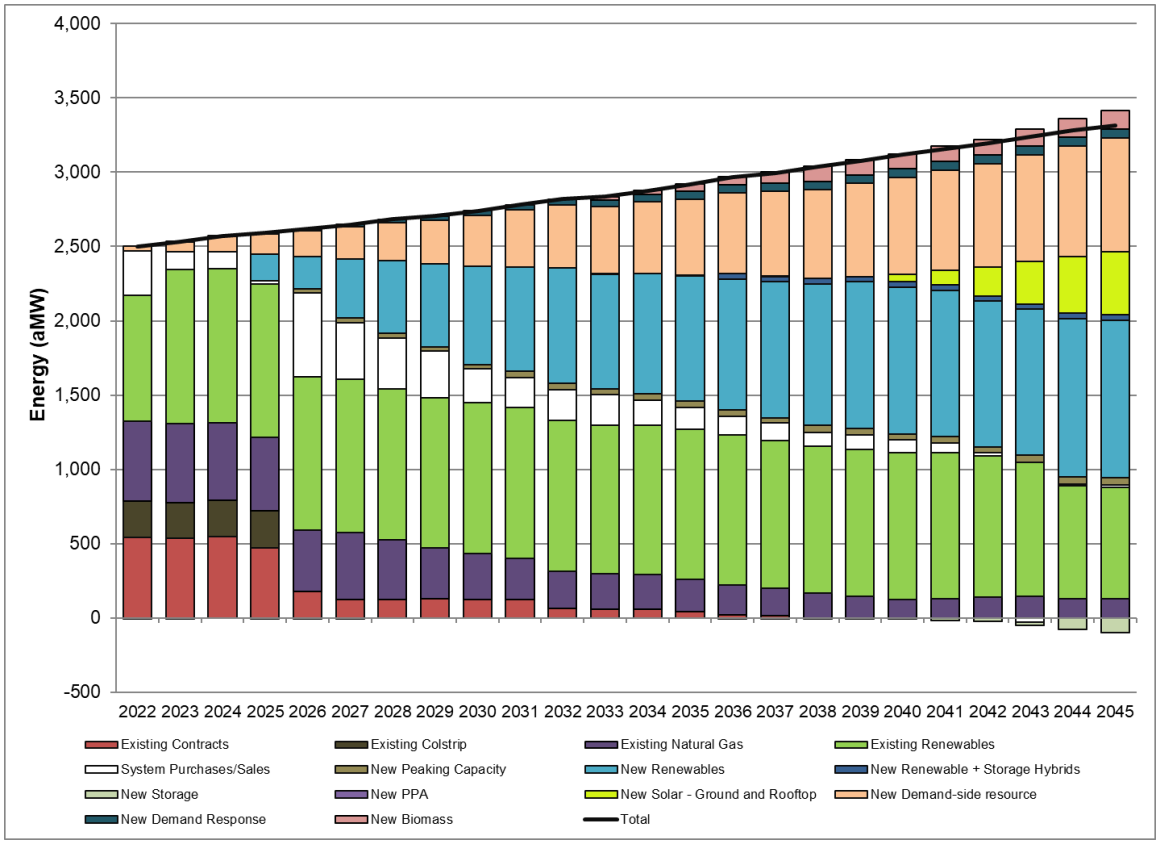
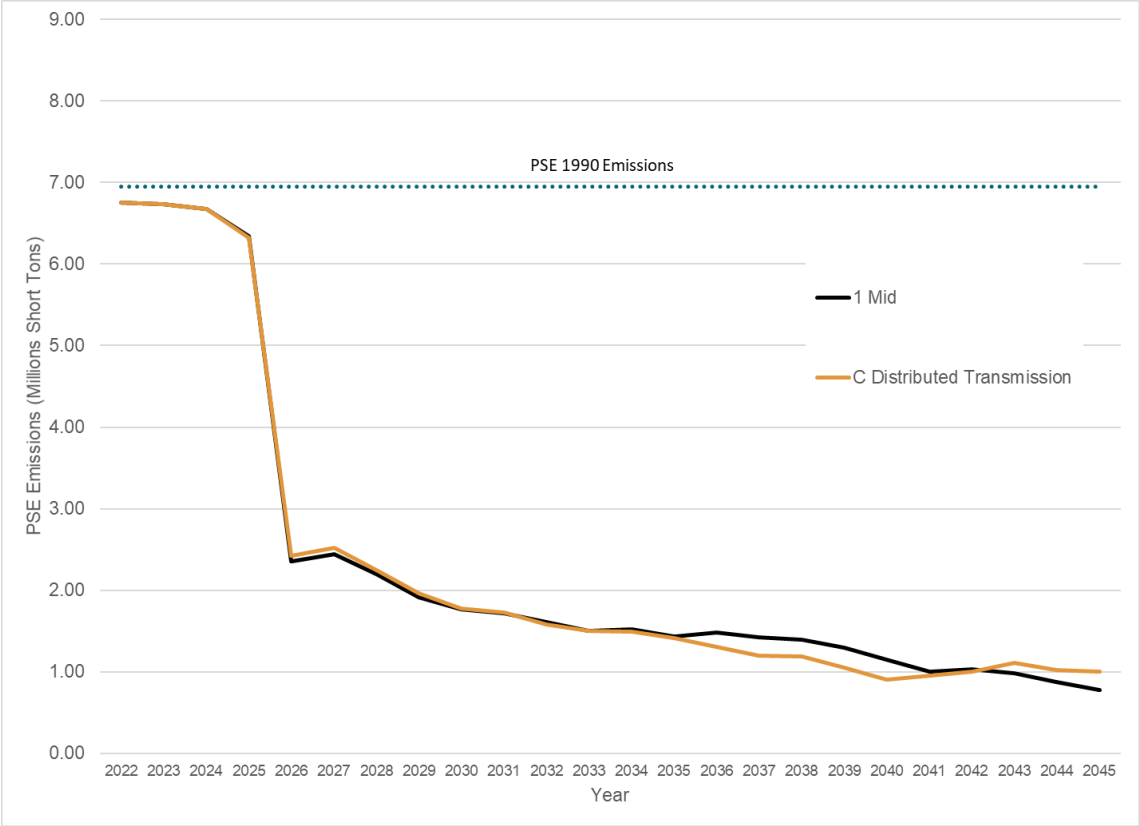


Figure 8-40: Direct Portfolio Emissions – Mid Scenario and Sensitivity C



D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined four "Tiers" of transmission availability, which increase transmission capacity over time. This sensitivity ramps in transmission availability over the modeling horizon.

Baseline: The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a limit of 1,500 MW of purchases from the Mid-C market and build limitations for Montana, Idaho and Wyoming based resources. **Sensitivity >** Sensitivity D assumes that transmission constraints increase over time, modeling Tier 1 constraints through 2025, Tier 2 through 2030, Tier 3 through 2035 and Tier 0 (generally unconstrained) after 2035. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline, plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. The Tiered transmission constraints modeled in Sensitivity D had relatively little impact on the portfolio composition compared to the Mid Scenario. Early in the modeling horizon,

Sensitivity D tends to select wind more often than solar compared to Mid Scenario. By the end of the modeling horizon, most resource builds are near those in the Mid Scenario. Costs and GHG emissions are also in line with those in the Mid Scenario. This suggests that transmission constraints (until the year 2035) have little influence on resource acquisition decisions. A similar result was observed in Sensitivity C.

ASSUMPTIONS. Sensitivity D assumes that transmission capacity availability outside of PSE's service territory ramps in over time. Figure 8-41 summarizes the transmission capacity assumptions for each Tier and associated timeframe. (See Chapter 5 for a complete description of the four transmission tiers and resource group regions.)

Figure 8-41: Sensitivity D Transmission Constraints

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**
Modeling Timeframe	**2035-2045**	**2022-2025**	**2025-2030**	**2030-2035**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

PORTFOLIO COSTS. The Sensitivity D portfolio is slightly more expensive over the modeling time horizon compared to the Mid Scenario portfolio, as shown in Figure 8-42. However, the 24-year levelized cost difference is less than $30 million, which suggests that transmission limitations do not strongly constrain resource builds over the 2022 to 2035 time horizon.

Figure 8-42: Portfolio Cost Comparison – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
D	Transmission/Build Constraints – Time-delayed (Option 2)	$15.54	$5.11	$20.65	$0.03

RESOURCE ADDITIONS. Resource additions for Sensitivity D are very similar to the Mid Scenario. This similarity suggests that transmission constraints (until the year 2035) do not have a significant impact on resources build decisions. Sensitivity D shifts away from eastern Washington solar and toward Washington wind due to wind's higher capacity factor, which results in more energy production early in the planning horizon. Sensitivity D also builds slightly more and longer-duration storage than the Mid Scenario. However, the increased storage builds in Sensitivity D occur after 2035, once transmission constraints have been lifted, which suggests the storage decisions were a result of the early focus on wind instead of solar. By 2024, wind and solar builds in Sensitivity D are nearly equal the Mid Scenario.

Sensitivity D selects conservation Bundle 11, which is more conservation than selected in the Mid Scenario (Bundle 10).

These resource build decisions are summarized in Figures 8-43 and 8-44.

Figure 8-43: Portfolio Additions – Mid Scenario and Sensitivity D, Transmission Build Constraints – Time Delayed (Option 2)

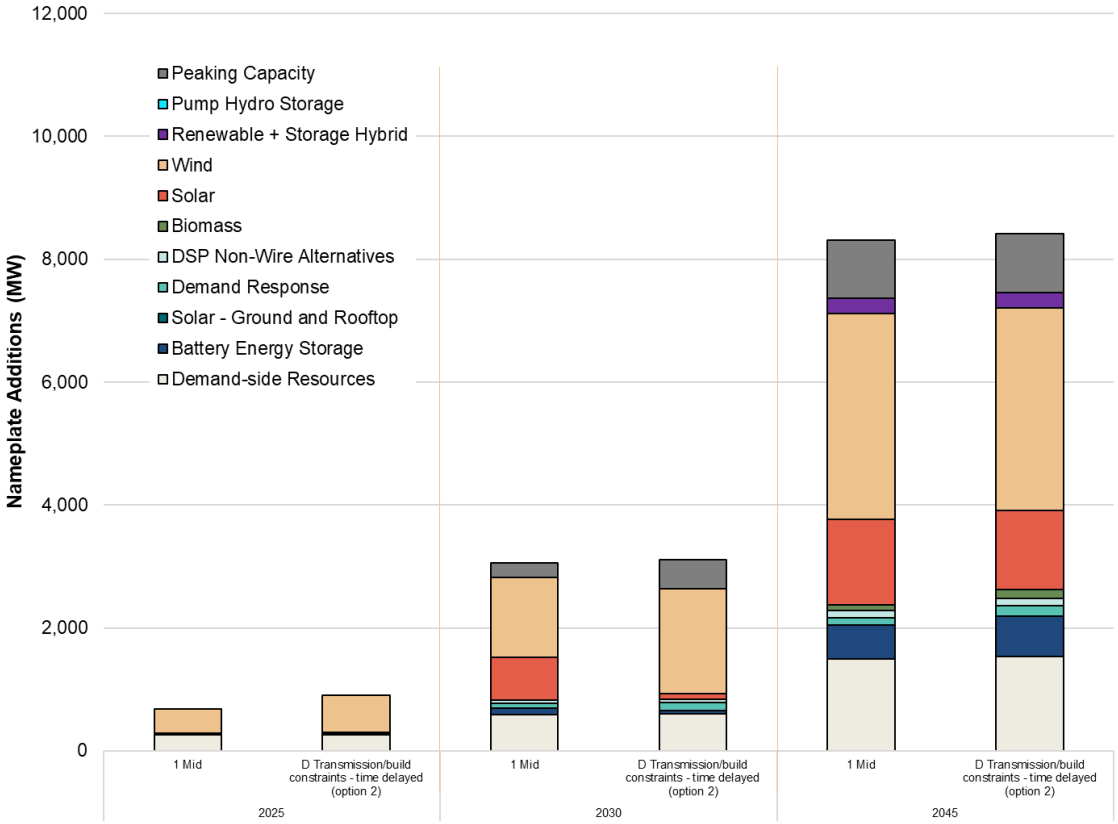


Figure 8-44: Portfolio Additions by 2045, Sensitivity D – Transmission Build Constraints – Time delayed (Option 2)

Resource Additions by 2045	1 Mid	D Transmission Build Constraints – Time delayed (Option 2)
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	650 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	180 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,730 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,295 MW
Wind	3,350 MW	3,300 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity examines the impact on portfolio costs when the capacity of firm transmission purchased with new resources is less than the nameplate capacity of the generating resource.

Baseline: New resources are acquired with transmission capacity equal to their nameplate capacity.
Sensitivity > New resources are acquired with less transmission capacity than nameplate capacity.

KEY FINDINGS. The benefit from contracting firm transmission less than the nameplate capacity of a renewable resource is highly site specific. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due the significant portion of time that wind resources spend at or near nameplate capacity (i.e., rated power).

ASSUMPTIONS. This sensitivity examines the trade-off between investing in the cost of firm transmission versus the cost of having to replace power lost to transmission curtailment because transmission less than nameplate capacity was acquired. This trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar.

The annual transmission cost for each resource was calculated using the fixed transmission cost of the resource (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh).

The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a "worst-case scenario" analysis, where it is assumed that all power produced can be used (i.e., production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

WIND RESULTS. Figure 8-45 shows the trade-off for 200 MW of generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios that provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (100 percent), therefore at 100 percent, there is no benefit or cost.

The results show that resources with high transmission costs (Wyoming and Idaho wind resources) return the greatest savings. All wind resources indicate at least some benefit in the range of transmission capacity reductions from around 99 percent to 96 percent of nameplate capacity. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero for resources with low fixed transmission costs because wind resources often produce close to their rated power. Figure 8-46 shows a typical histogram for a generic wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Most often, therefore, when the wind farm is generating power, it is likely to be using all available transmission.

Fixed transmission costs for Idaho and Wyoming resources are more than four times higher than for eastern Washington wind resources. These premium fixed transmission costs are why Idaho and Wyoming wind resources have such a large potential benefit compared to other wind resources.

Figure 8-45: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

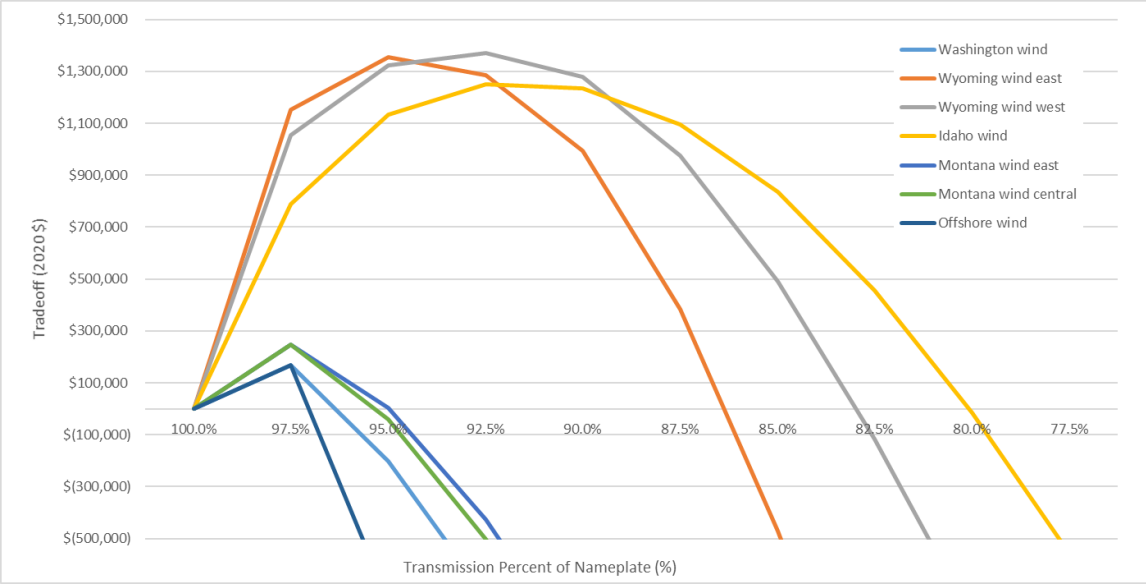
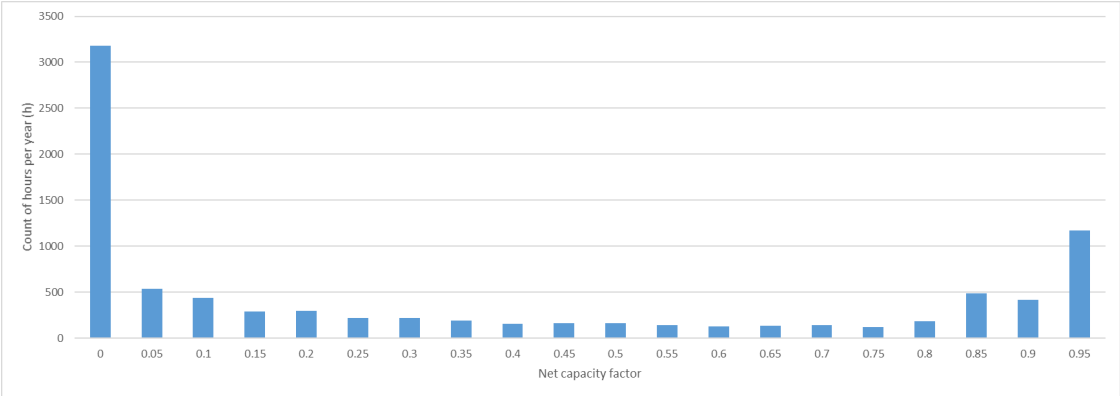


Figure 8-46: Net Capacity Factor Distribution of a Typical Wind Resource



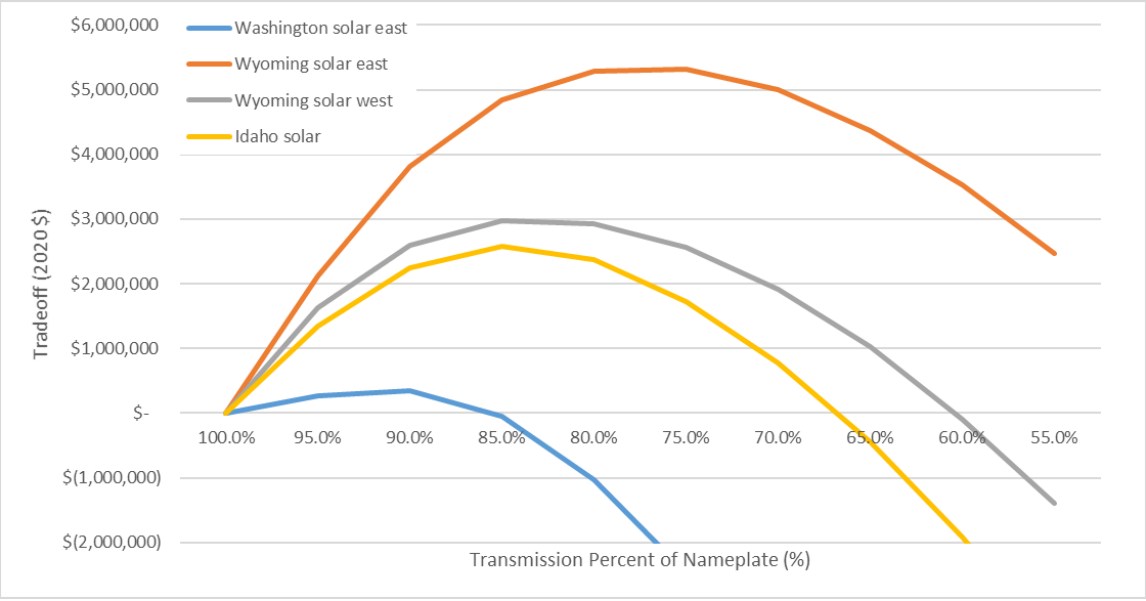
The results of this investigation came as a surprise to PSE. Initial investigations in the 2021 Draft IRP showed very little benefit for all wind resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the results are highly site specific.

PSE will continue to investigate the potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability of resources, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

SOLAR RESULTS. Figure 8-47 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity that equals resource nameplate capacity (100 percent), therefore at 100 percent there is no benefit or cost.

Similar to the wind resources discussed above, the benefit of under-built transmission capacity is highly site specific and strongly correlated to fixed transmission cost. Regions with high fixed transmission costs (Idaho and Wyoming) have significantly more benefit than regions with low fixed transmission costs (eastern Washington).

Figure 8-47: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



Similar to the wind results above, the results of the solar investigation came as a surprise to PSE. Initial investigations for the 2021 draft IRP showed very little benefit for all solar resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the circumstances are highly site specific.

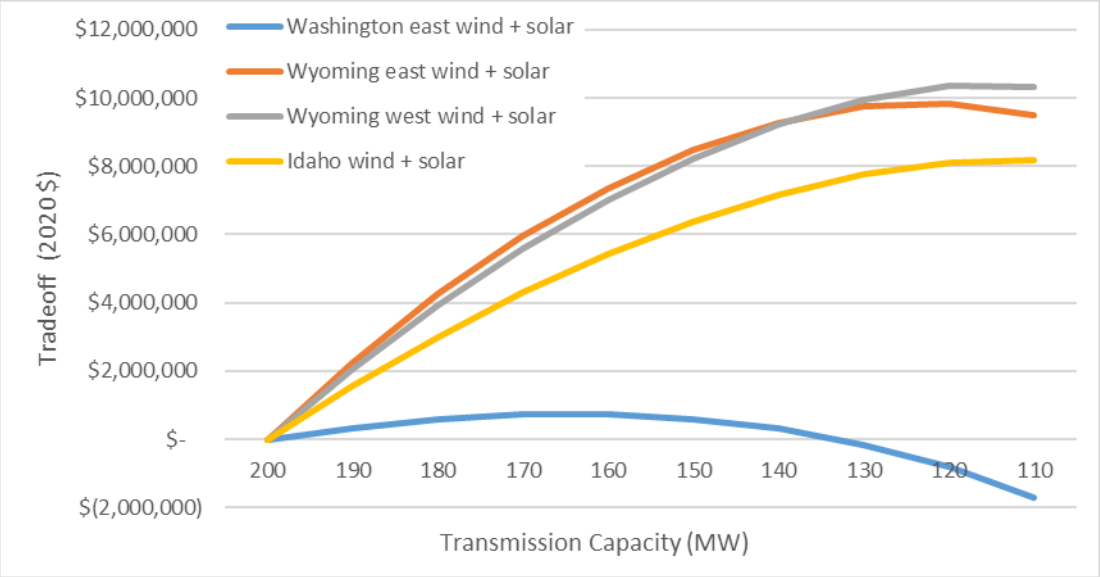
PSE will continue to investigate potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

NEXT STEPS. In addition to the transmission sensitivities described above, PSE also looked at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter production may benefit from co-location with solar resources that have higher summer production. Second, wind resources with higher overnight production may benefit from co-location with solar resources that, by nature, only produce power during the day. Optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources may realize cost savings, as opposed to securing firm transmission for both resources individually.

Figure 8-48 shows the possible benefits of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. Cost benefits from reducing firm transmission contracts are strongly correlated to fixed transmission cost, as seen in the analysis of individual wind and solar resources. Interestingly, on a dollar-per-megawatt nameplate capacity basis, the benefit of the co-location is even greater than for individual wind or solar resources, which shows a synergistic relationship between co-located wind and solar resources that share transmission capacity.

PSE looks forward to continuing to learn more about benefits of co-located resources in future IRP cycles.

Figure 8-48: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



Conservation Alternatives

F. 6-year Ramp Rate for Conservation
G. Non-energy Impacts
H. Social Discount Rate

These sensitivities were performed to assess changes in the implementation rate, financial structure, and overall effectiveness of conservation measures.

Baseline: Conservation resources are implemented over 10 years using PSE's baseline assumptions on costs and energy savings.
Sensitivity F > Conservation measures are implemented over 6 years instead of 10 years, and associated costs and energy savings are updated.
Sensitivity G > Conservation measures include additional non-energy impacts. Assuming there are additional benefits not captured in the original dataset, this increases the amount of energy savings from conservation and demand response.
Sensitivity H > The discount rate of DSR projects is changed from 6.8 percent to 2.5 percent. When the discount rate is decreased, the present value of future DSR savings is increased.

KEY FINDINGS. Costs and resource builds remain relatively stable across changes to the conservation inputs. Sensitivity F (6-year Ramp) selected Bundle 9, Sensitivity G (Non-energy

Impacts) selected bundle 8 and Sensitivity G (Social Discount Rate) selected bundle 6, compared to bundle 10 in the Mid Scenario. Though lower conservation bundles were selected, additional demand response measures were added. Changes to the conservation assumptions push more energy savings measures into lower bundles so the portfolio selects similar or lower amounts of conservation for lower costs. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045, compared to making adjustments around ramp rates and discount rates.

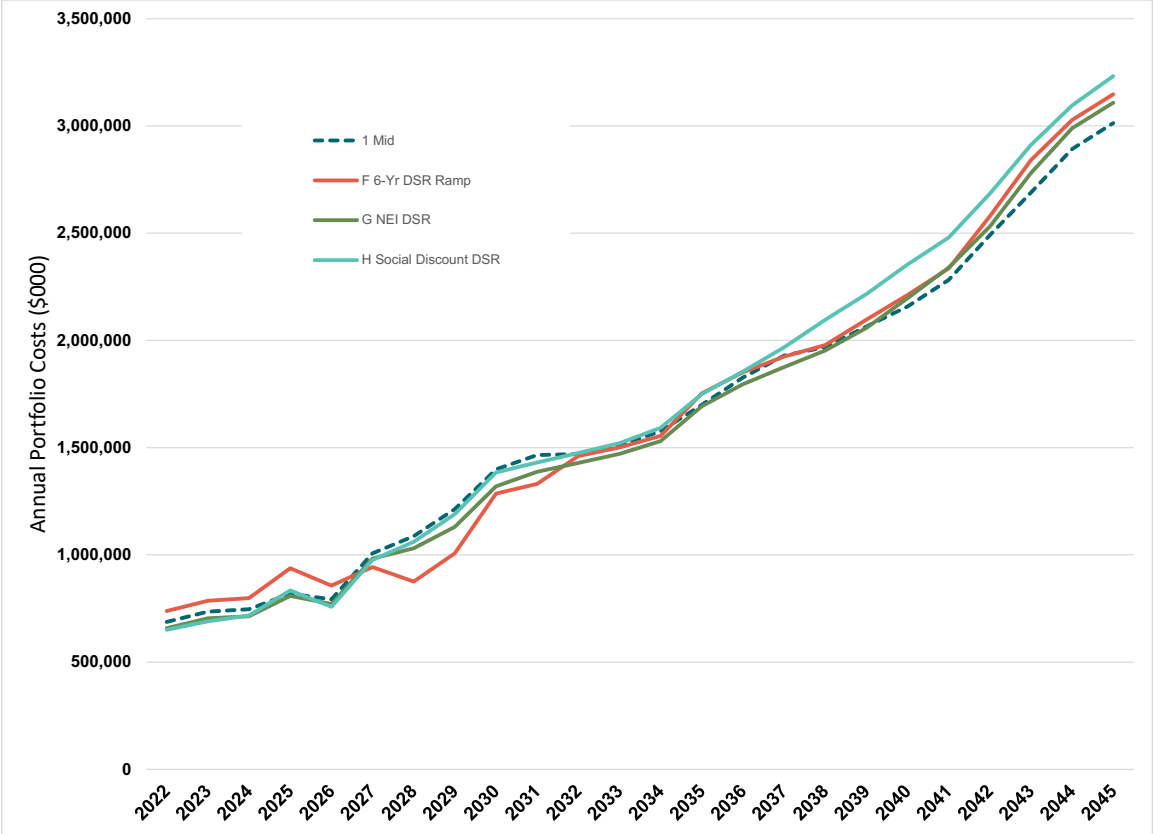
ASSUMPTIONS. These portfolios keep all underlying assumptions from the Mid Scenario portfolio, then change the costs and energy savings of the conservation measures available as resources. All DSR inputs in the Mid Scenario and Sensitivities F, G and H, can be found in Appendix H.

ANNUAL PORTFOLIO COSTS. Across all three sensitivities, changes to the overall costs of the portfolio are minor. In Sensitivity F, there is virtually no difference in overall portfolio cost compared to the Mid Scenario, although different timelines for the additions of Washington wind, Wyoming wind and Washington east solar lead to differences in annual costs in the earlier years of the simulation. Sensitivity G shows a small decrease in costs, achieving the same energy savings benefits as Sensitivity F at a lower cost conservation bundle. Sensitivity G also adds a frame peaker by 2045 compared to the Mid Scenario and Portfolio F, resulting in fewer battery builds. Frame peaker builds are a less expensive way to increase capacity and peak capacity, but the overall changes to the portfolio costs are small. Sensitivity H shows a minor increase in costs as a result of increased battery and renewable hybrid builds in the later years of the simulation. Otherwise, the portfolio costs of Sensitivity H follow the annual cost trends of the Mid Scenario.

Figure 8-49: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities F, G and H

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
F	6-Year Conservation Ramp Rate	$15.54	$5.09	$20.63	$0.01
G	Non-energy Impacts for DSR	$15.24	$5.12	$20.36	($0.26)
H	Social Discount Rate for DSR	$15.77	$5.16	$20.94	$0.32

Figure 8-50: Annual Portfolio Costs – Mid Scenario and Sensitivities F, G and H



RESOURCE ADDITIONS. Figures 8-51 and 8-52 compare the nameplate capacity additions of the Mid Scenario to Sensitivities F, G and H. Resource builds do not change significantly across the portfolios. Minor differences are seen in the timing of renewable resource construction and total nameplate capacity built. Any reductions in standalone renewable capacity are offset by increased hybrid resources or battery storage resources. Sensitivity H shows the largest increase in overall capacity, adding 100 MW of wind, 250 MW of hybrid resources and 100 MW of battery storage by 2045. Sensitivity F builds an additional 250 MW of hybrid resources and 75 MW of battery resources, but reduces standalone wind resources by 200 MW. Sensitivity G increases battery storage and standalone wind resources by 200 MW each, but reduces hybrid resource builds by 250 MW by 2045. These differences from the Mid Scenario are minor and affect the later years of the simulation.

Figure 8-51: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

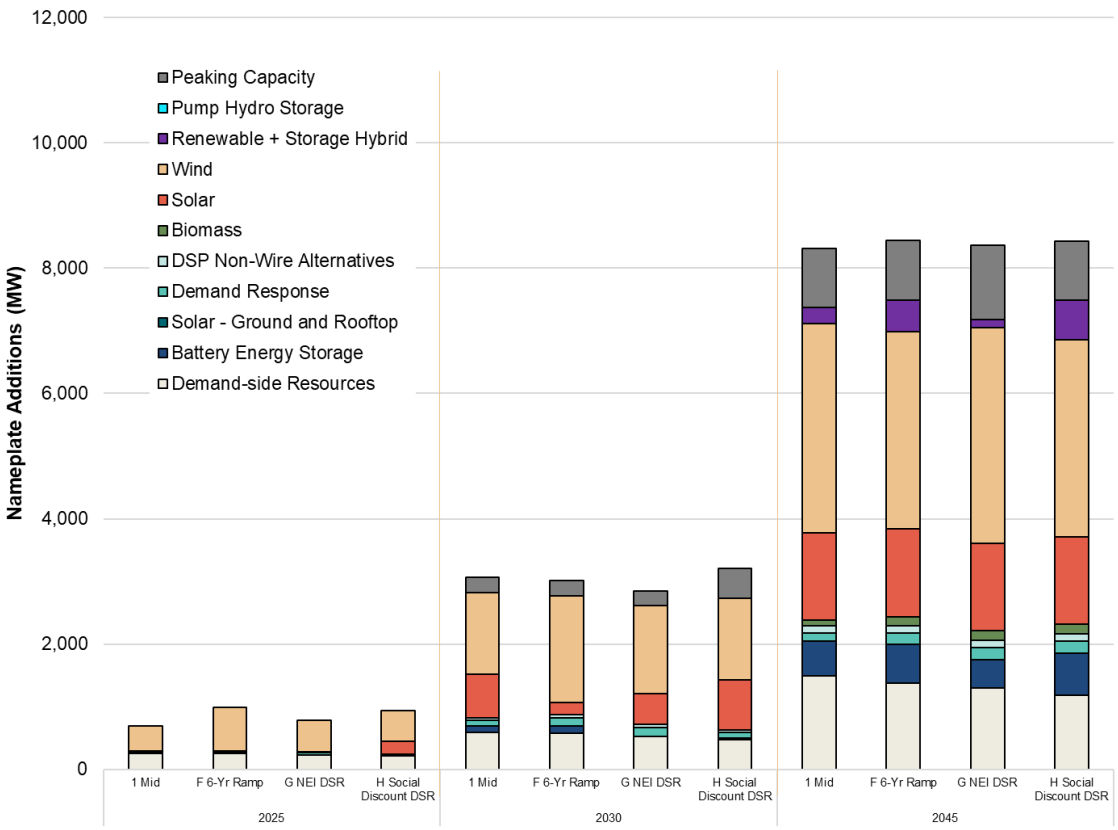


Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

Resource Additions by 2045	1. Mid	F. 6-Yr DSR Ramp	G. NEI DSR	H. Social Discount DSR
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,179 MW
Battery Energy Storage	550 MW	625 MW	450 MW	675 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	175 MW	188 MW	195 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,694 MW	4,993 MW	4,691 MW
Biomass	90 MW	150 MW	150 MW	150 MW
Solar	1,393 MW	1,394 MW	1,393 MW	1,391 MW
Wind	3,350 MW	3,150 MW	3,450 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	500 MW	125 MW	625 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	1,185 MW	948 MW

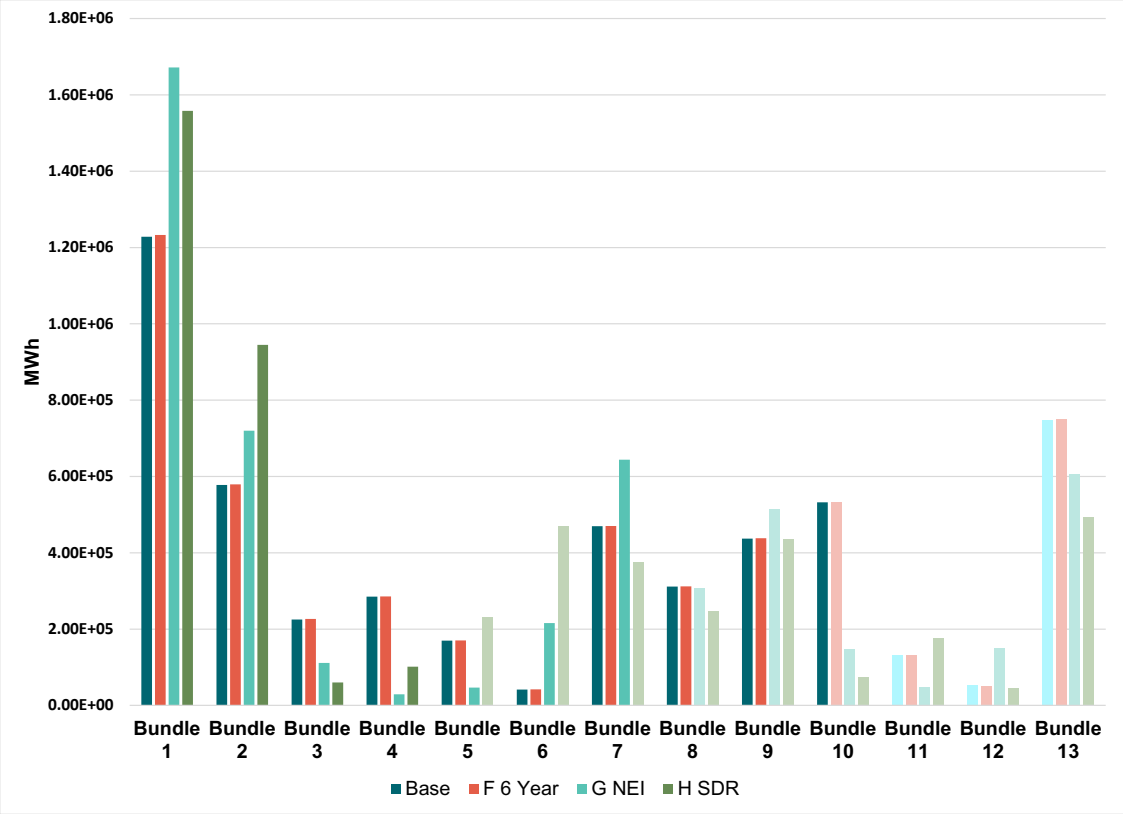
CHANGES IN CONSERVATION AND DEMAND RESPONSE. The primary focus of these sensitivities was to assess the implementation of changes to the available conservation measures. Figure 8-53 shows the final conservation selections in each sensitivity.

Figure 8-53: Conservation Measures Selected – Mid Scenario and Sensitivities F, G and H

Sensitivity	Conservation Bundle	Average Annual Energy Savings from Conservation	Number of Demand Response Measures	Capacity of Demand Response Measures Added
Mid Scenario	Bundle 10	718 aMW	3	123 MW
F - 6-Year Ramp	Bundle 9	659 aMW	5	175 MW
G - Non-Energy Impacts	Bundle 7	624 aMW	8	188 MW
H - Social Discount Rate	Bundle 4	538 aMW	9	195 MW

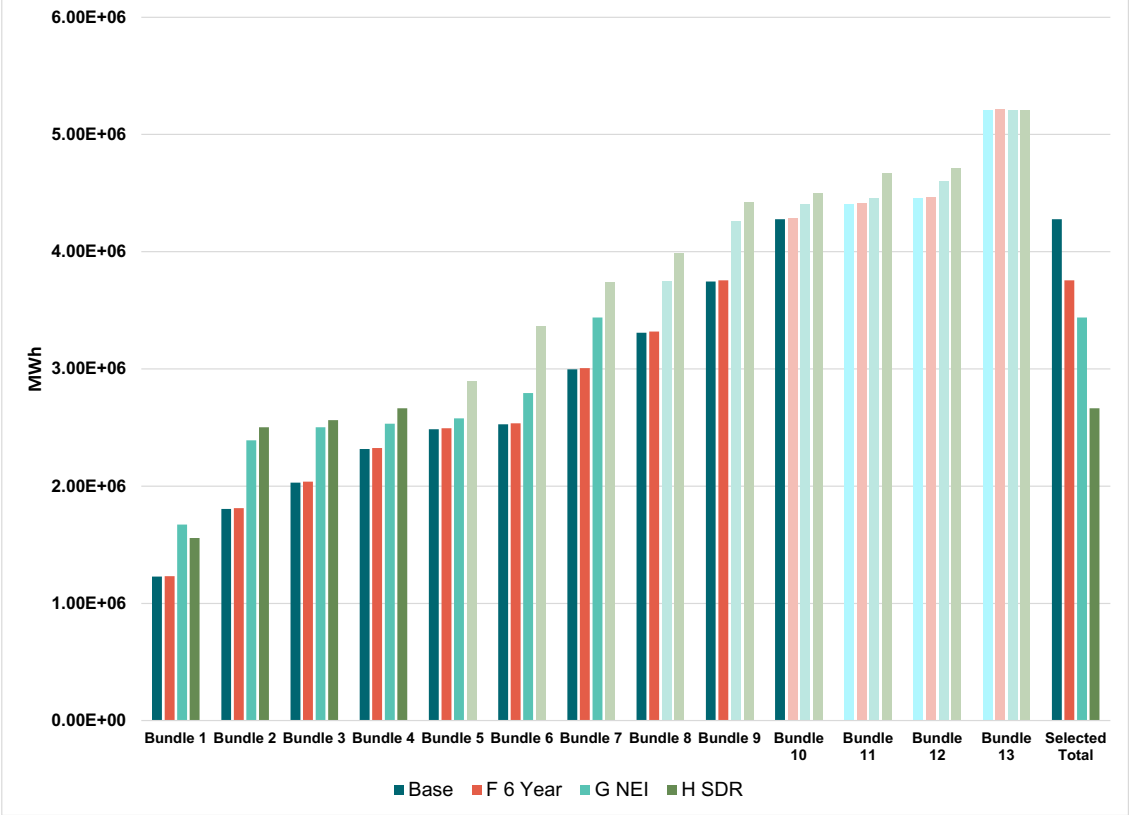
Updates to the DSR inputs changed the energy and cost values associated with each conservation measure. Since each conservation bundle is a collection of individual conservation programs within a price range, the assessment of individual measures within a bundle is not possible. However, the aggregate attributes of each bundle can be seen. Figure 8-39 shows the incremental energy savings provided by each bundle by 2045. In order to add a bundle in the AURORA model, the previous bundle must also be added (excluding Bundle 1), each bundle is dependent on adding the previous bundle. Figure 8-54 shows the cumulative energy savings provided by a selected bundle and all preceding bundles.

Figure 8-54: Incremental Energy Savings Provided by Each Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Across the DSR sensitivities, adjustments to the underlying DSR attributes push more energy savings into lower bundles. In the long-term capacity expansion model, AURORA responds to these changes by adding less conservation while increasing investment in demand response measures. This trend is shown in Figure 8-55 where the cumulative energy savings within each bundle is greater for Sensitivities F, G and H than the Mid Scenario (Base).

Figure 8-55: Cumulative savings Achieved by Each Incremental Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Social Cost of Greenhouse Gases and CO_2 Regulation

I. SCGHG as an Externality Cost in the Portfolio Model Only
J. SCGHG as an Externality Cost in the Portfolio Model and Dispatch Model

The goal of these sensitivities is to compare methodologies for applying the social cost of greenhouse gases to portfolios.

Baseline: The SCGHG is included as a planning adder to emitting resources in the long-term capacity expansion (LTCE) model. The planning adder is a fixed cost.
Sensitivity I > The SCGHG is included as an externality cost to emitting resources in the LTCE model. This externality cost is a variable cost of dispatch, in contrast to the fixed cost of the planning adder.

Sensitivity J > As in Sensitivity I, the SCGHG is included as an externality cost to emitting resources in the LTCE model. In addition, the SCGHG is included as a dispatch cost in the hourly dispatch model as a carbon tax.

KEY FINDINGS. Including the SCGHG in the LTCE and hourly dispatch models produces portfolios similar to the Mid Scenario. This is expected, as the CETA renewable requirement is the main driver of reduced emissions and thermal resources. In Portfolio I, costs and emissions are nearly identical to the Mid Scenario. In Portfolio J, which also includes the SCGHG as a carbon tax, the overall revenue requirement increases over the course of the planning horizon, but the largest increase occurs while Colstrip is operating from 2022 to 2025. Portfolio J also increases the use of market purchases to meet demand and shows a small decrease in overall emissions compared to the Mid Scenario.

ASSUMPTIONS. In both Sensitivity I and J, the SCGHG defined by CETA is simply applied as a variable cost on the dispatch of emitting resources. Figure 8-56 shows the value of the SCGHG as defined by CETA and the conversion used in AURORA.

In Sensitivity J, the SCGHG is also applied as a carbon tax in the hourly dispatch model. This requires an updated power price dataset since a carbon tax would impact the operations of all utilities in Washington.

Figure 8-56: CETA Definition of SCGHG and the Converted Values Used in AURORA

Year	2019$ / metric ton CO2	AURORA Input 2012$ / short ton CO2
2022	77.73	59.33
2023	78.95	60.25
2024	80.16	61.18
2025	82.59	63.03
2026	83.81	63.96
2027	85.02	64.89
2028	86.24	65.81
2029	87.45	66.74
2030	88.67	67.67
2031	89.88	68.60
2032	91.09	69.52
2033	92.31	70.45
2034	93.52	71.38
2035	94.74	72.30
2036	95.95	73.23
2037	98.38	75.08
2038	99.60	76.01
2039	100.81	76.94
2040	102.03	77.86
2041	103.24	78.79
2042	104.46	79.72
2043	105.67	80.65
2044	106.88	81.57
2045	108.10	82.50

ANNUAL PORTFOLIO COSTS. Figures 8-57 and 8-58 illustrate the breakdown of costs between the Mid Scenario and Sensitivities I and J.

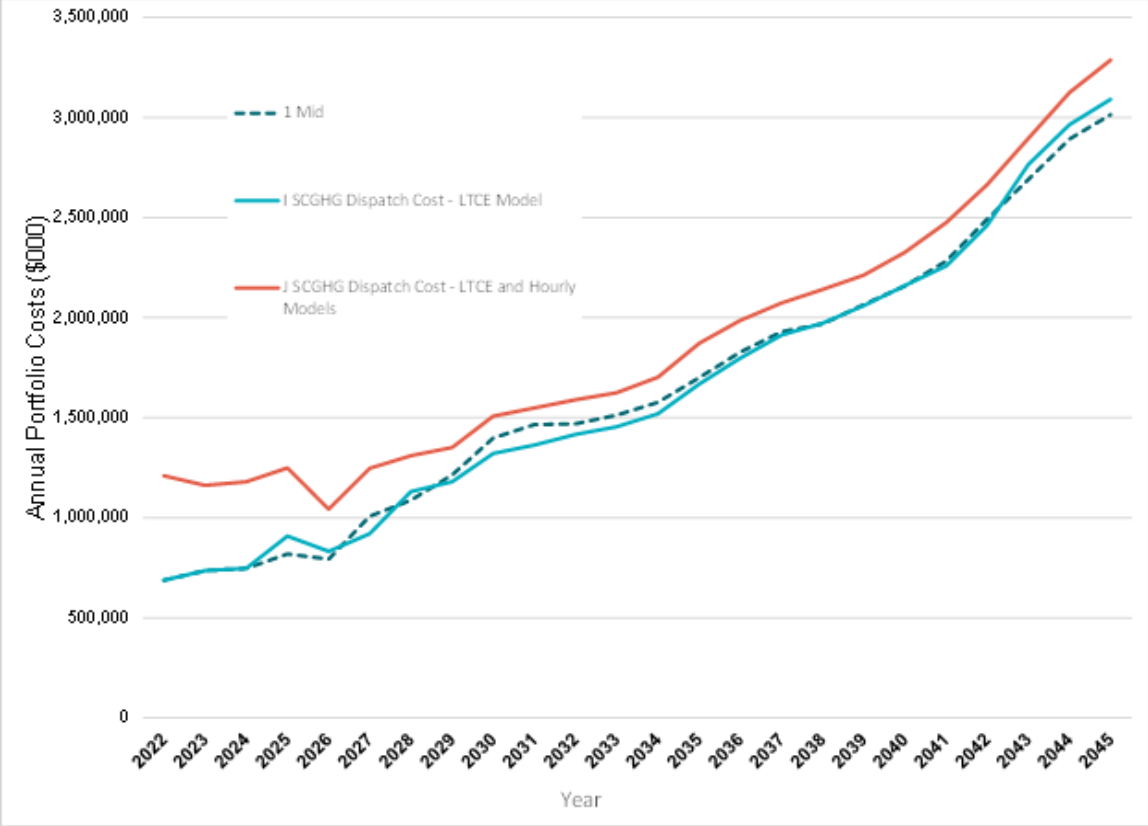
The final builds of the portfolios are similar, though Portfolio J greatly increases the emission costs of the portfolio in earlier years since the emissions of Colstrip and other thermal resources are now also taxed in the hourly dispatch model. After the retirement of Colstrip, as the carbon tax delays the construction of more flexible capacity resources, Portfolio J emissions do decrease compared to the portfolios in the Mid Scenario and Sensitivity I. Despite these differences, the cost trends of the portfolios remain the same after 2036. Sensitivity J has a higher overall cost since the SCGHG is now included as a dispatch cost and in the electric price forecast. This makes it difficult to divide out the revenue requirement from SCGHG. Even though sensitivity J has a lower SCGHG cost, it only reflects the cost of generating resources; the cost of market is in the revenue requirement, so it is hard to compare this portfolio against the Mid scenarios.

Figure 8-57: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivities I and J

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
I	SCGHG Externality Cost – LTCE Model Only	$15.41	$5.10	$20.51	($0.11)
J	SCGHG Externality Cost – LTCE Model and Hourly Dispatch*	$18.45	$4.81	$23.26	$2.64

** Sensitivity J uses a different electric price forecast than the Mid Scenario.*

Figure 8-58: Annual Portfolio Costs – Mid Scenario, Sensitivity I and Sensitivity J



RESOURCE ADDITIONS. Figures 8-59 and 8-60 compare the nameplate capacity additions of the Mid Scenario to Sensitivities I and J. Both sensitivities select Bundle 10 for conservation and reach 2045 with a similar builds of batteries and renewables. Timing of resources builds is different for each sensitivity, but both result in similar portfolios to the Mid Scenario.

Sensitivity I builds one less frame peaker than the Mid Scenario, but adds 55 MW of reciprocating peakers. It also builds 200 MW less of Washington wind and 100 MW less of Washington solar than the Mid Scenario, but adds 125 MW of hybrid resources to the portfolio. Overall, Sensitivity I adds 325 MW more battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 575 MW of 4-hour lithium-ion batteries built compared to the Mid Scenario's 50 MW.

Sensitivity J builds two fewer frame peakers than the Mid Scenario, but adds 273 MW of reciprocating peakers. Washington wind capacity increases by 200 MW by 2045, and Washington solar capacity decreases by 400 MW, netting the same overall intermittent renewable nameplate capacity as Portfolio I. Portfolio J also adds 125 MW of hybrid resources. Overall, Sensitivity J adds an additional 300 MW more of battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 400 MW of 6-hour flow batteries built compared to no 6-hour flow batteries the Mid Scenario.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities I and J

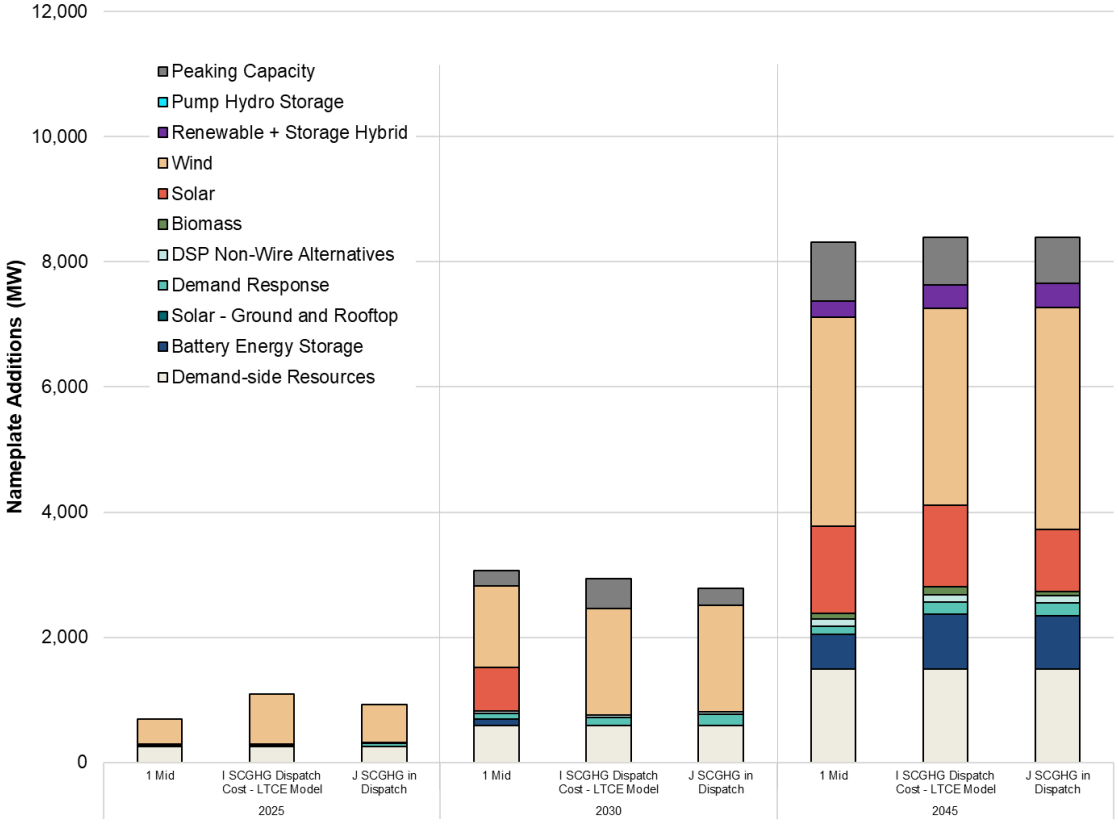


Figure 8-69: Portfolio Additions – Mid Scenario and Sensitivities I and J

Resource Additions by 2045	1 Mid	I SCGHG Dispatch Cost - LTCE Model	J SCGHG Dispatch Cost - LTCE and Hourly Models
Demand-side Resources	1,497 MW	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	875 MW	850 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	188 MW	205 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,579 MW	4,606 MW
Biomass	90 MW	135 MW	60 MW
Solar	1,393 MW	1,294 MW	996 MW
Wind	3,350 MW	3,150 MW	3,550 MW
Renewable + Storage Hybrid	250 MW	375 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	766 MW	747 MW

EMISSIONS. Emissions are the largest difference between Sensitivity I and J. Figure 8-61 compares the direct emissions of the Mid Scenario, Sensitivity I and Sensitivity J. Portfolio J builds a similar amount of peaking capacity as Portfolio I, but relies much more heavily on market purchases to meet demand. Including the market purchase emission rate assumed in CETA brings Portfolio J in line with Sensitivity I, showing a modest decrease in emissions as shown in Figure 8-62. This is expected, as the CETA renewable requirement is the main driver of emissions reductions, not the SCGHG.

Figure 8-61: Direct Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases not included)

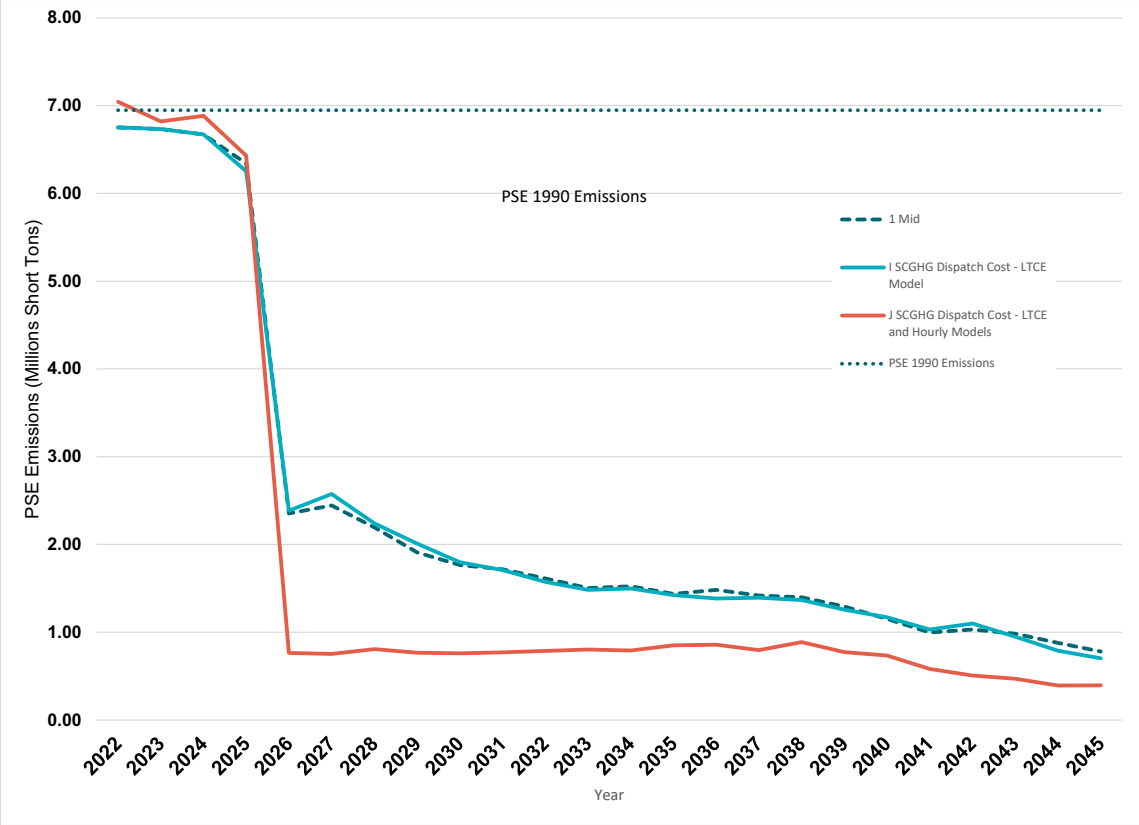
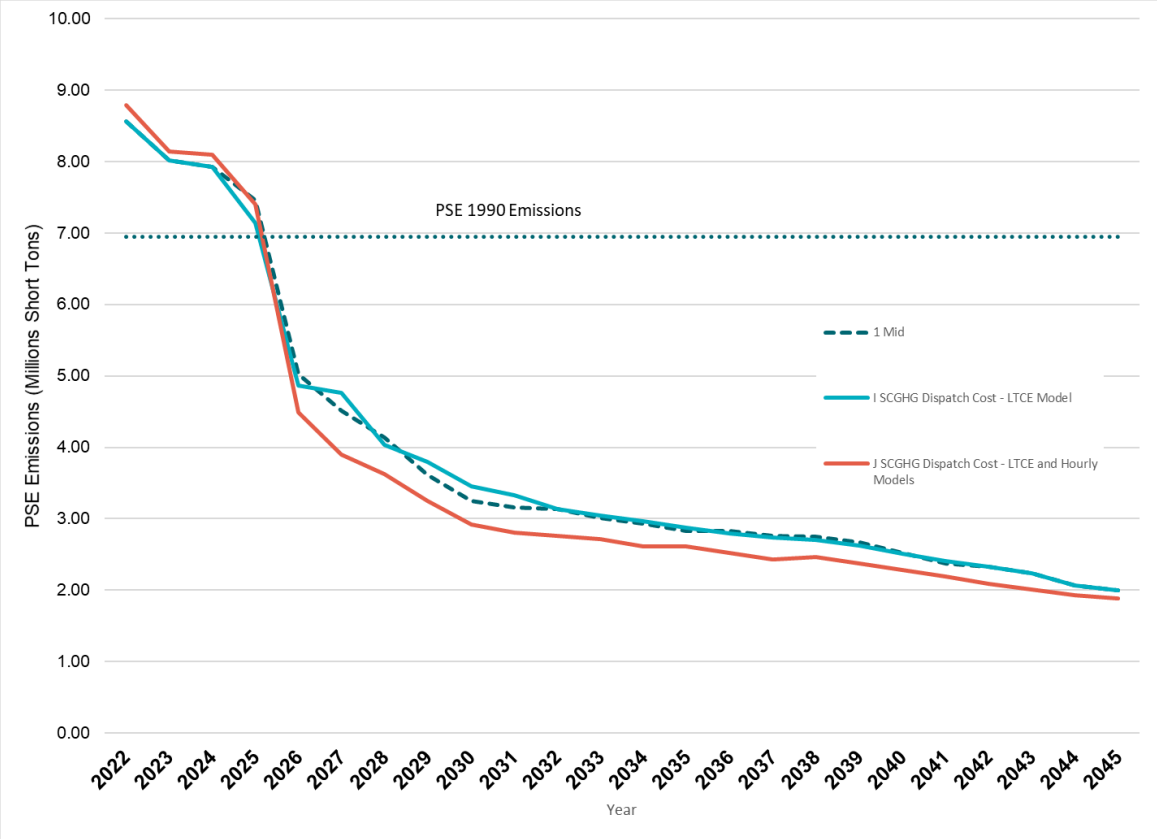


Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



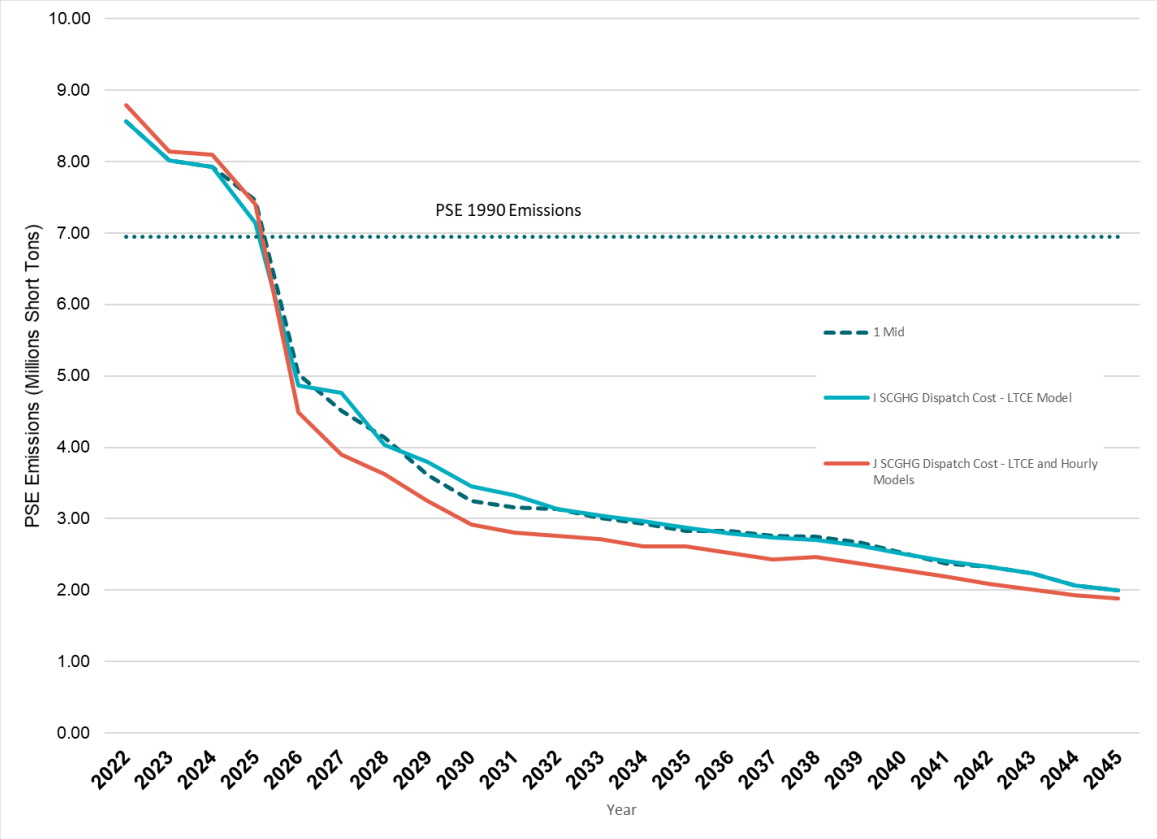
K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

ASSUMPTIONS. The sensitivity is updated to include the AR5 methodology of calculating upstream emissions. Figure 8-63 compares the emission rates of resources in the Mid Scenario and Sensitivity K. All other underlying assumptions from the Mid Scenario portfolio are kept the same.

Figure 8-63: Upstream Emission Rates – Mid Scenario (AR4) and Sensitivity K (AR5)

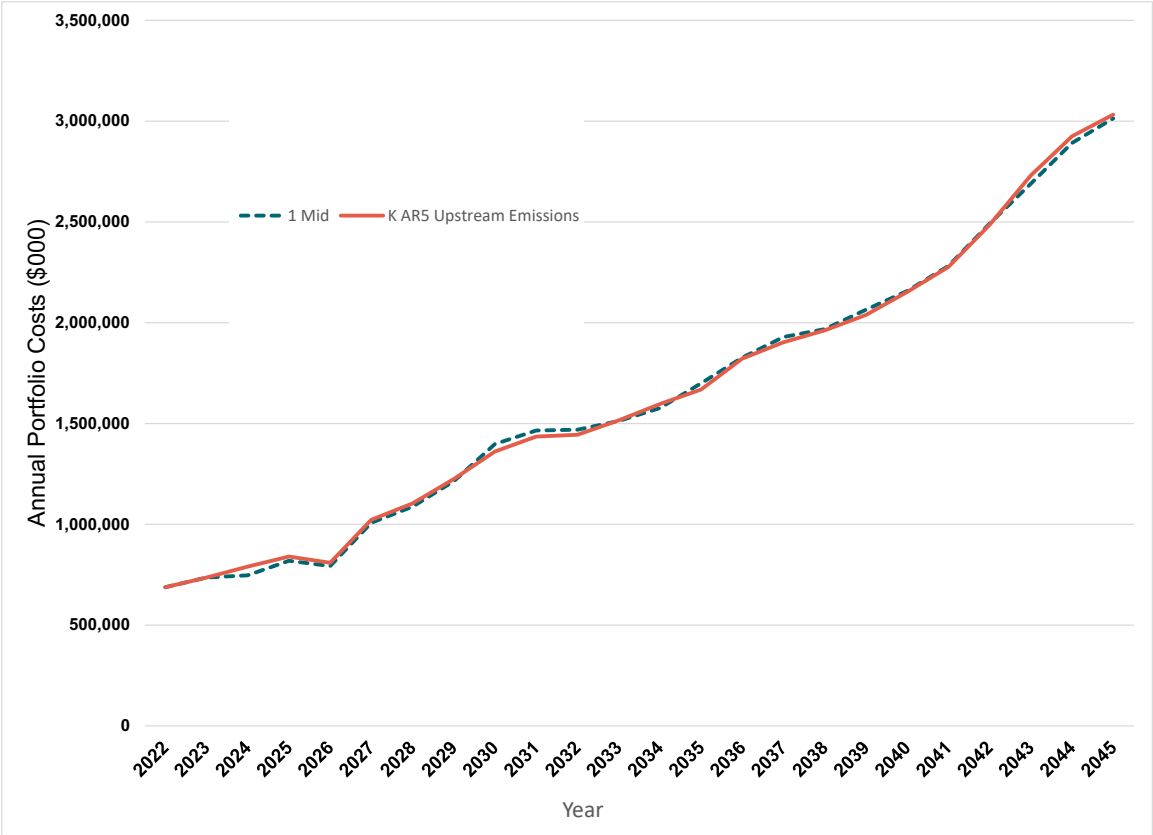
Resource	Mid Scenario AR4 Upstream Emission Rates (lb/mmBtu)	Sensitivity K AR5 Upstream Emission Rates (lb/mmBtu)
New Frame Peaker	23	24
New Recip Peaker	23	24

ANNUAL PORTFOLIO COSTS. The costs of the Sensitivity K and Mid Scenario portfolios are nearly identical. There are no significant changes in portfolio builds that would lead to changes in costs. The increased emissions costs are expected, as thermal plants are associated with slightly higher emissions.

Figure 8-64: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity K

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
K	**AR5 Emissions**	$15.56	$5.14	$20.71	$0.09

Figure 8-65: Annual Portfolio Costs – Mid Scenario and Sensitivity K



RESOURCE ADDITIONS. Figures 8-66 and 8-67 compare the nameplate capacity additions in the portfolios of the Mid Scenario and Sensitivity K. Both select Bundle 10 for conservation, and Sensitivity K selects four additional demand response resources for a total of seven. Minor differences are seen in the timing of wind and solar resources. Nearly the same amount of peaking capacity, solar and hybrid capacity is built by 2045 in both portfolios. However, 200 MW less of wind and an additional 75 MW of battery storage are built by 2045 in the Sensitivity K portfolio.

Figure 8-66: Portfolio Additions – Mid Scenario and Sensitivity K

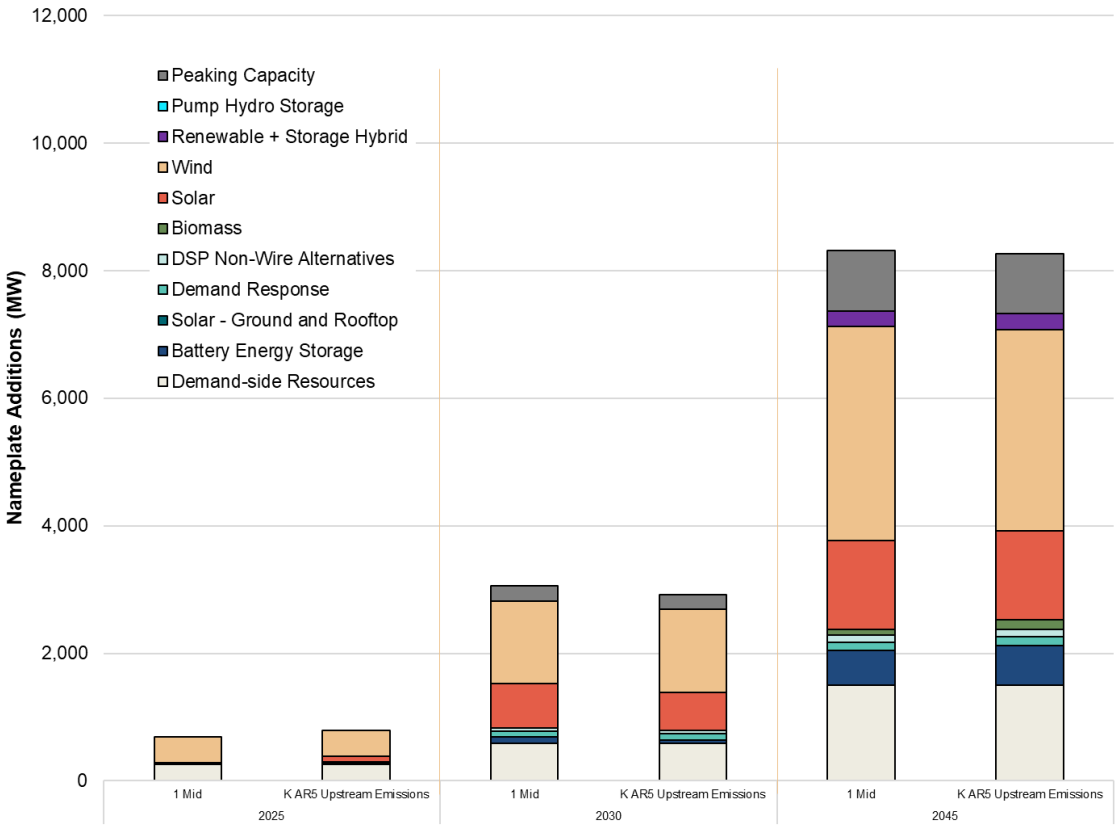
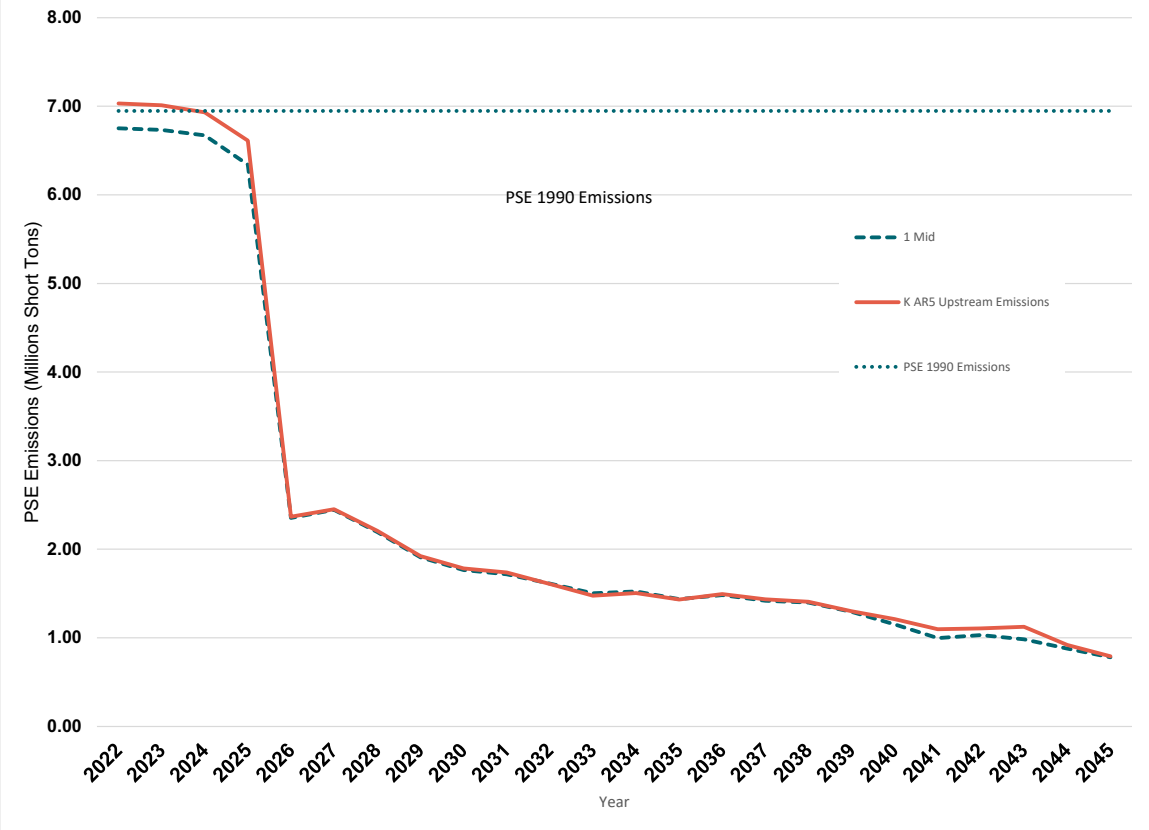


Figure 8-67: Portfolio Additions – Mid Scenario and Sensitivity K

Resource Additions by 2045	1 Mid	K AR5 Upstream Emissions
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	625 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	140 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,693 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,393 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

EMISSIONS. Changing to the AR5 methodology does not significantly change the emissions of Portfolio K. Figure 8-68 compares the emissions of the Mid Scenario and Portfolio K. The change to the AR5 methodology makes the most difference in the earlier years when dispatch of the natural gas resources are higher. Over time, the dispatch of the natural gas resources drops significantly enough that there is negligible change in emissions between the two portfolios.

Figure 8-68: Annual Emissions – Mid Scenario and Portfolio K



L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

This sensitivity examines the impact of adding a Federal CO_2 tax in addition to SCGHG as a fixed cost adder for thermal plants during the resource selection process.

Baseline: The SCGHG is included as a planning adder (fixed cost) to thermal resources during the LTCE modeling process.

Sensitivity L > In addition to SCGHG as a planning adder (fixed cost) to thermal resources during the LTCE modeling process, a Federal CO_2 tax is applied to emissions from thermal resources during both the LTCE modeling process and the hourly dispatch model. This Federal CO_2 tax is applied to the power prices of the portfolio as well, which affects all WECC resources.

KEY FINDINGS. There is relatively little change to the renewable resource additions in Sensitivity L since the CETA requirement drives renewable portfolio additions rather than the SCGHG or a Federal CO_2 tax. However, adding a Federal CO_2 alters the dispatch of thermal resources. The capacity factor of all thermal plants declines overtime as the Federal CO_2 tax increases during the planning horizon.

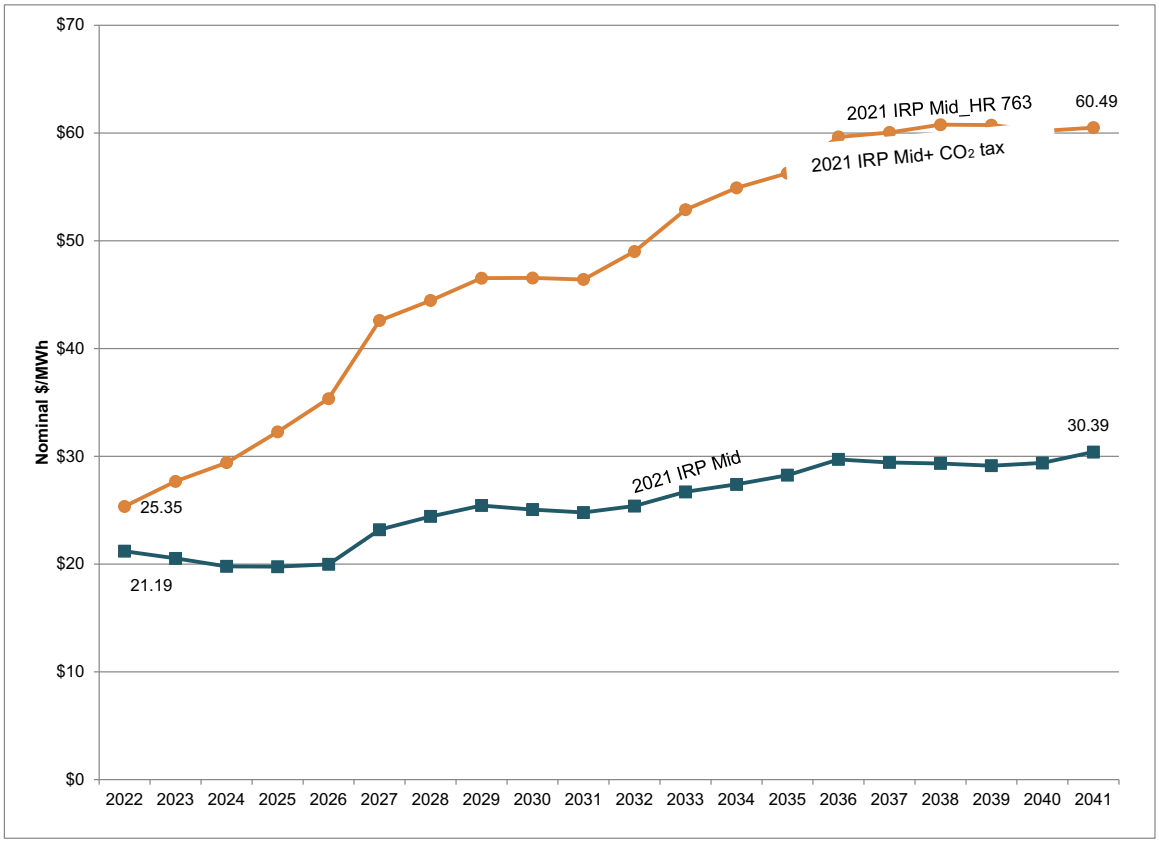
ASSUMPTIONS. For this sensitivity, PSE modeled the Energy Innovation and Carbon Dividend Act of 2019 (H.R. 763) that was introduced in Congress on January 2019, as the assumed federal CO_2 tax. The bill imposes a fee on the carbon content of fuels, including crude oil, natural gas, coal or any other product derived from those fuels. The fee is imposed on the producers or importers of the fuels and is equal to the greenhouse gas content of the fuel multiplied by the carbon fee rate. The rate begins at $15 in 2019, increases by $10 each year, and is subject to further adjustments based on progress in meeting specified emissions reduction targets. Figure 8-69 shows the value of the Federal CO_2 tax included in AURORA and the SCGHG used for this sensitivity.

Figure 8-69: SCGHG under CETA and the Federal CO_2 Tax under H.R. 763
(in 2012 dollars per short ton)

Year	SCGHG 2012$ / short ton CO_2	Federal CO_2 Tax 2012$ / short ton CO_2
2022	59.33	12.33
2023	60.25	20.35
2024	61.18	28.37
2025	63.03	36.20
2026	63.96	43.83
2027	64.89	51.28
2028	65.81	58.55
2029	66.74	65.64
2030	67.67	72.56
2031	68.60	79.31
2032	69.52	85.90
2033	70.45	92.32
2034	71.38	98.59
2035	72.30	104.70
2036	73.23	110.67
2037	75.08	116.49
2038	76.01	122.17
2039	76.94	127.71
2040	77.86	133.11
2041	78.79	138.38
2042	79.72	143.53
2043	80.65	148.55
2044	81.57	153.44
2045	82.50	158.22

Using the Federal CO_2 tax requires an updated power price forecast since the Federal tax would impact the operations of all thermal plants in the WECC. Figure 8-70 compares the addition of a Federal CO_2 tax to Mid-C power prices with the Mid Scenario power price forecast. The 20-year levelized Mid-C power price is $43.11 per MWh, an increase of almost $19 per MWh over the Mid Scenario power prices.

Figure 8-70: Mid-C Power Prices – Mid Scenario and Sensitivity L
(in 2012 dollars per short ton)

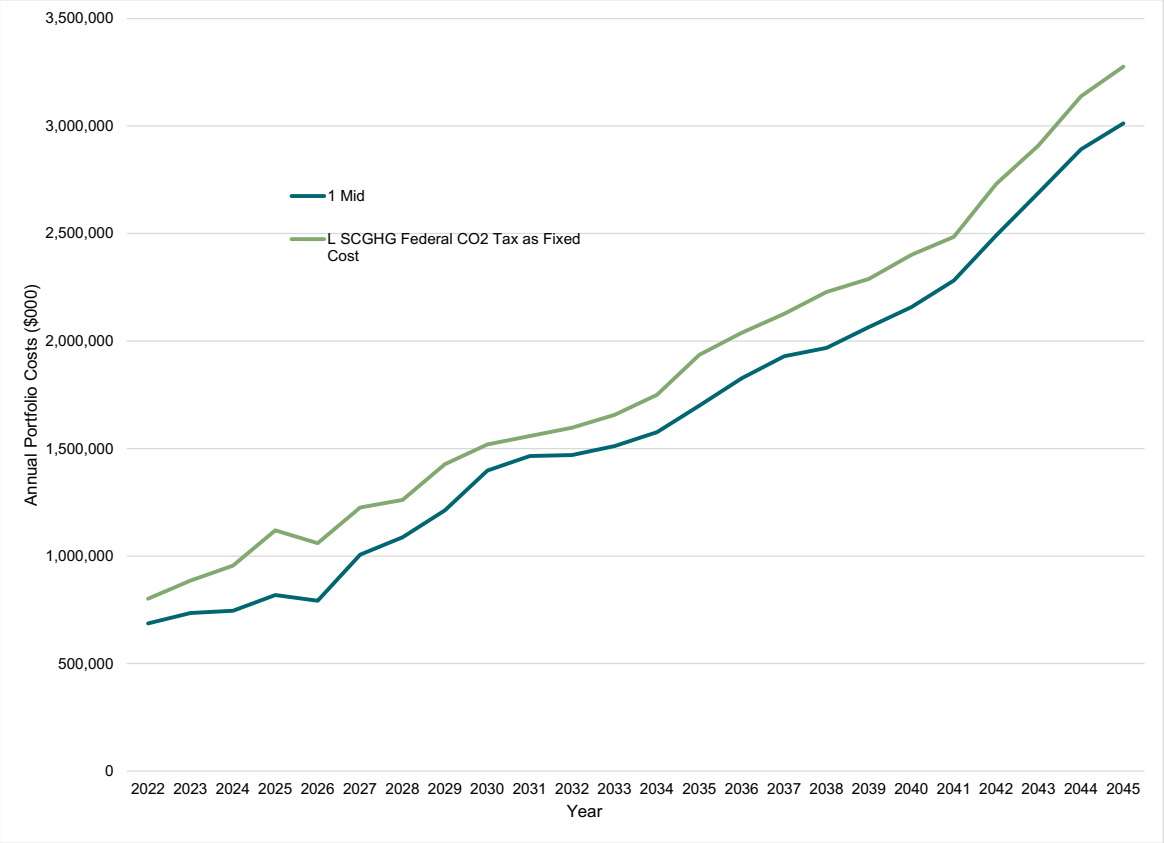


ANNUAL PORTFOLIO COSTS. The Sensitivity L portfolio costs are $2.24 billion higher than Mid Scenario costs. The higher costs can be attributed to the increase in market purchases and the selection of conservation Bundle 11 in Sensitivity L instead of conservation Bundle 10 in the Mid Scenario portfolio. Emissions costs in Sensitivity L are lower since thermal plants are dispatching less and generating lower emissions.

Figure 8-71: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity L

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	$17.77	$4.71	$22.47	$2.24

Figure 8-72: Annual Portfolio Costs – Mid Scenario and Sensitivity L



RESOURCE ADDITIONS. Figure 8-73 compares the nameplate capacity additions in the Mid Scenario and Sensitivity L portfolios. Adding the Federal CO_2 tax not only reduced the amount of flexible capacity resources added, but it also changed the mix of those flexible capacity resources. Sensitivity L adds a combined-cycle turbine in 2026, while the Mid Scenario adds a frame peaker in 2026. Sensitivity L also selects a higher conservation bundle (Bundle 11 compared to Bundle 10 in the Mid Scenario) and two additional demand response resources for a total of five. Minor differences are seen in the portfolio builds for solar, wind and hybrid capacity built by 2045.

Figure 8-73: Portfolio Additions – Sensitivity L and Mid Scenario

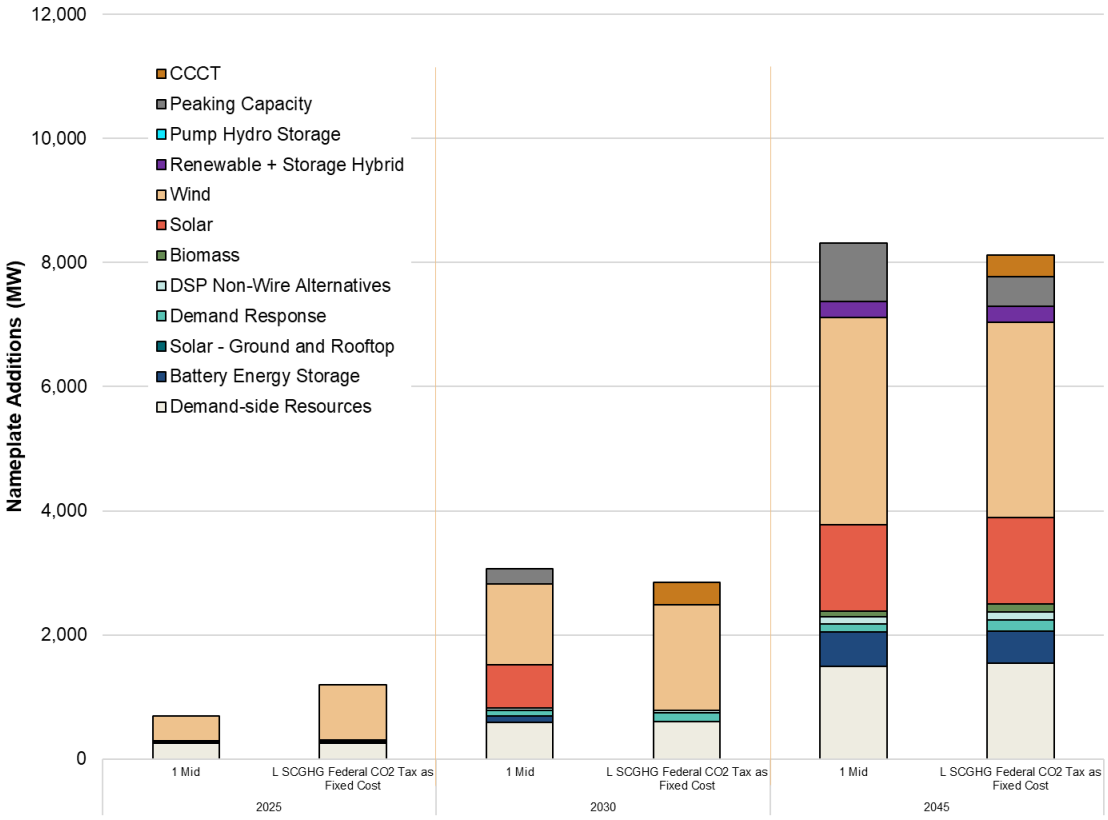


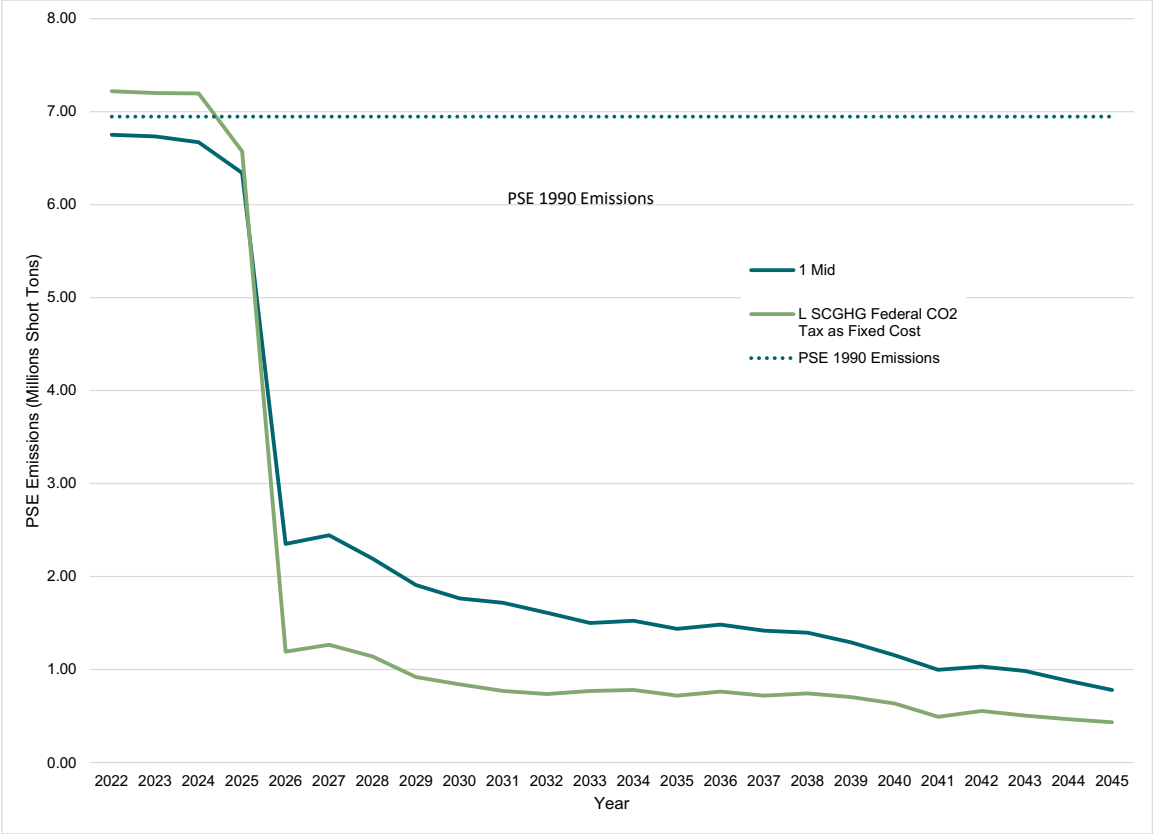
Figure 8-74 compares the nameplate capacity additions of the Mid Scenario and Sensitivity L portfolios by 2045.

Figure 8-74: Portfolio Additions – Mid Scenario and Sensitivity L

Resource Additions by 2045	1 Mid	L Federal CO_2 Tax SCGHG as Fixed Cost
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	183 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,680 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,395 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW
CCCT	0 MW	355 MW

EMISSIONS. Inclusion of a Federal CO_2 tax changed the emissions of Portfolio L significantly. In Portfolio L, after a large decline in emissions following the retirement of Centralia and Colstrip in 2026, existing and new thermal plants dispatch less and generate lower emissions due to the cost hurdle imposed by the Federal CO_2 tax. As a result, market purchases increased in Sensitivity L to make up for the decline in energy from thermal plants. Figure 8-75 compares the emissions of the Mid Scenario and Sensitivity L portfolios.

Figure 8-75: Annual Emissions – Mid Scenario and Portfolio L



Emissions Reduction

M. Alternative Fuel for Peakers

This sensitivity examines the effects of replacing the fuel supply for new frame peaker resources with a renewable fuel source, specifically biodiesel.

Baseline: New frame peaker resources are supplied with natural gas as their primary fuel source.
Sensitivity > New frame peaker resources are supplied with biodiesel as their primary fuel source.

KEY FINDINGS. In Sensitivity M, substituting biodiesel for natural gas in new frame peakers has only subtle impacts on the resulting portfolio. The 24-year levelized portfolio costs remain relatively unchanged, and resource additions are very similar to the Mid Scenario. GHG emissions are reduced slightly over the course of the modeling horizon. Biodiesel may be a feasible, cost-effective option for fueling peaking capacity resources while attaining CETA's zero emission goals and maintaining grid reliability.

ASSUMPTIONS. In Sensitivity M, new frame peaker resources are supplied with biodiesel as their primary fuel source. It is assumed that there are negligible differences between natural gas and biodiesel-fueled frame peakers in plant capital costs and fixed and variable operations and maintenance costs. Biodiesel is only available to frame peakers; new reciprocating peakers, new combined-cycle plants. Existing thermal resources are fueled with natural gas.

The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020 dollars, adjusted for inflation annually) over the entire study period.

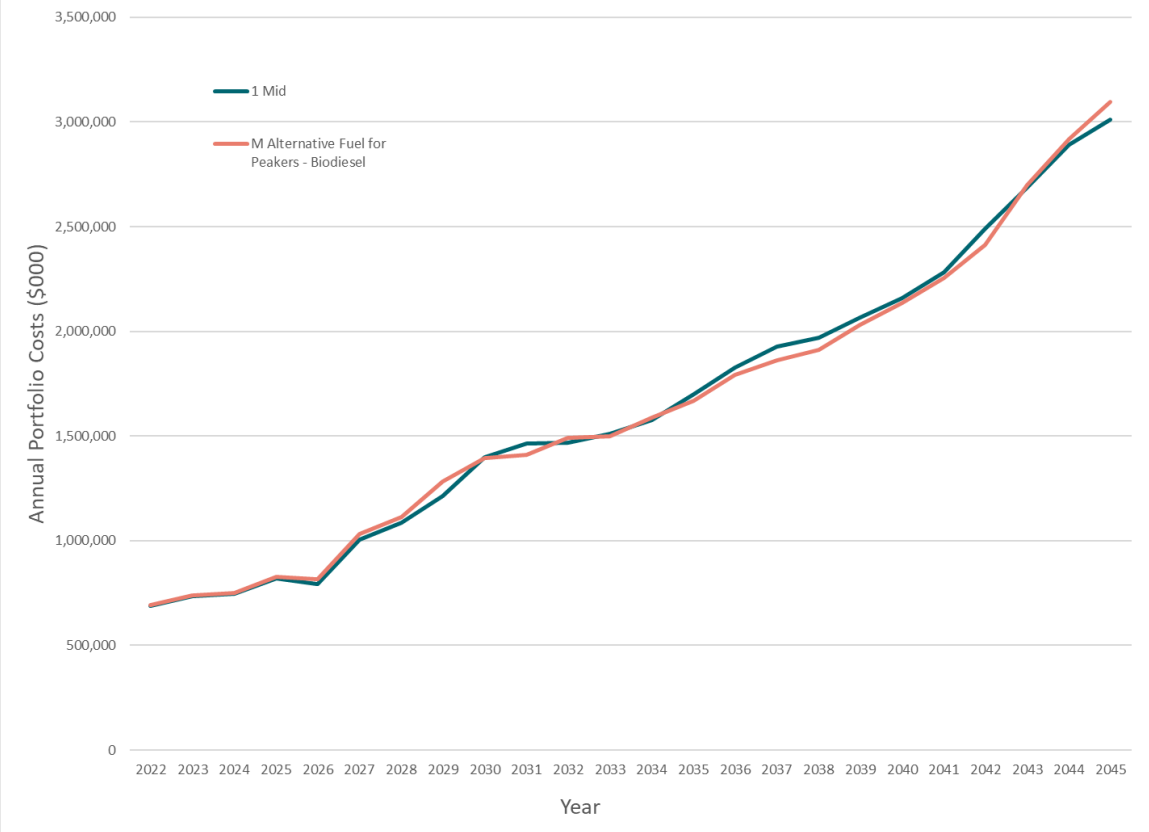
Given the anticipated constraints on biodiesel fuel supply, the flexibility benefit of frame peakers was removed ($0/kW-yr) in Sensitivity M as compared to the flexibility benefit of $23.45/kW-yr for frame peakers in the Mid Scenario.

PORTFOLIO COSTS. Figures 8-76 and 8-77 compare the breakdown of costs between the Mid Scenario and Sensitivity M portfolios. The 24-year levelized cost of Sensitivity M is nearly equal to the cost of Mid Scenario. However, the social cost of greenhouse gases is $100 million less in Sensitivity M compared to the Mid Scenario due to the use of a carbon neutral fuel for new frame peakers.

Figure 8-76: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity M

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
M	Alternative Fuel for Peakers	$15.53	$4.99	$20.52	($0.10)

Figure 8-77: Annual Portfolio Costs – Mid Scenario and Sensitivity M



RESOURCE ADDITIONS. Figures 8-78 and 8-79 compare the nameplate capacity additions of the Sensitivity M and Mid Scenario portfolios. Resource additions for Sensitivity M are very similar to those in the Mid Scenario. Both add the same quantity of peaking capacity, hybrid resources and similar quantities of renewable resources. Sensitivity M builds slightly more solar and slightly less wind than the Mid Scenario, and Sensitivity M selects conservation Bundle 11, whereas the Mid Scenario selects Bundle 10.

Figure 8-78: Portfolio Additions – Sensitivity M and the Mid Scenario

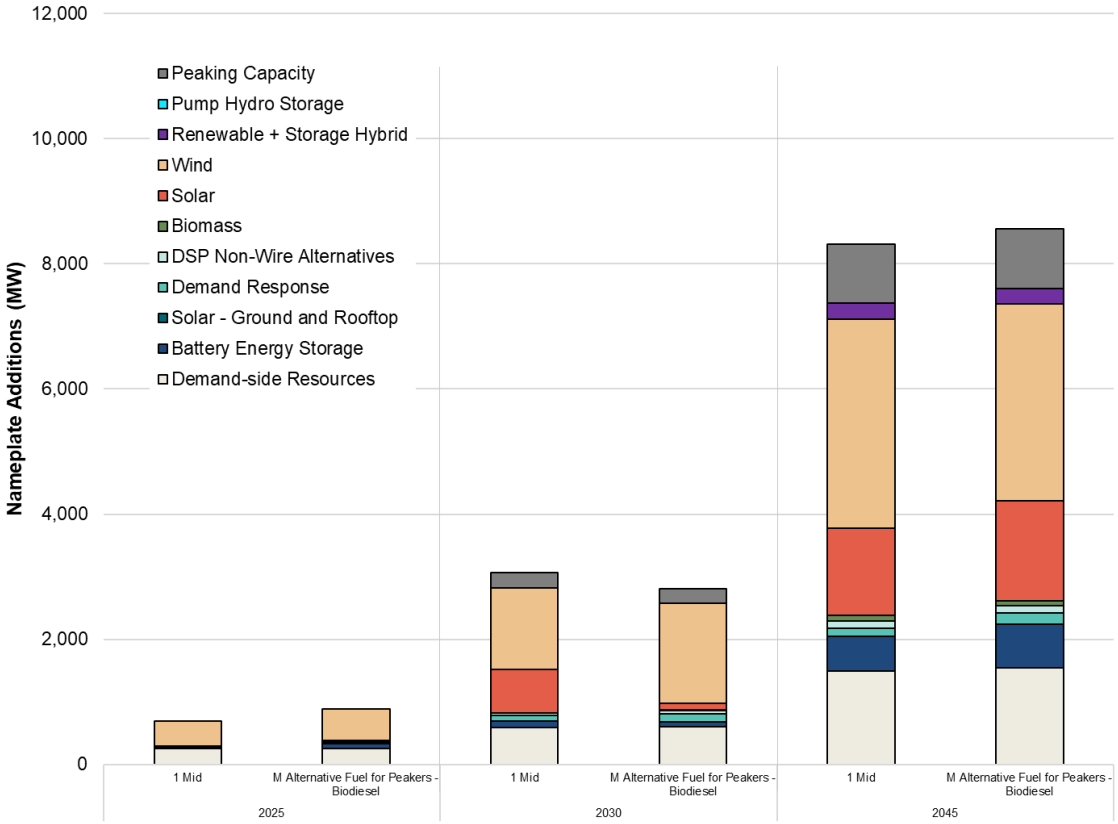
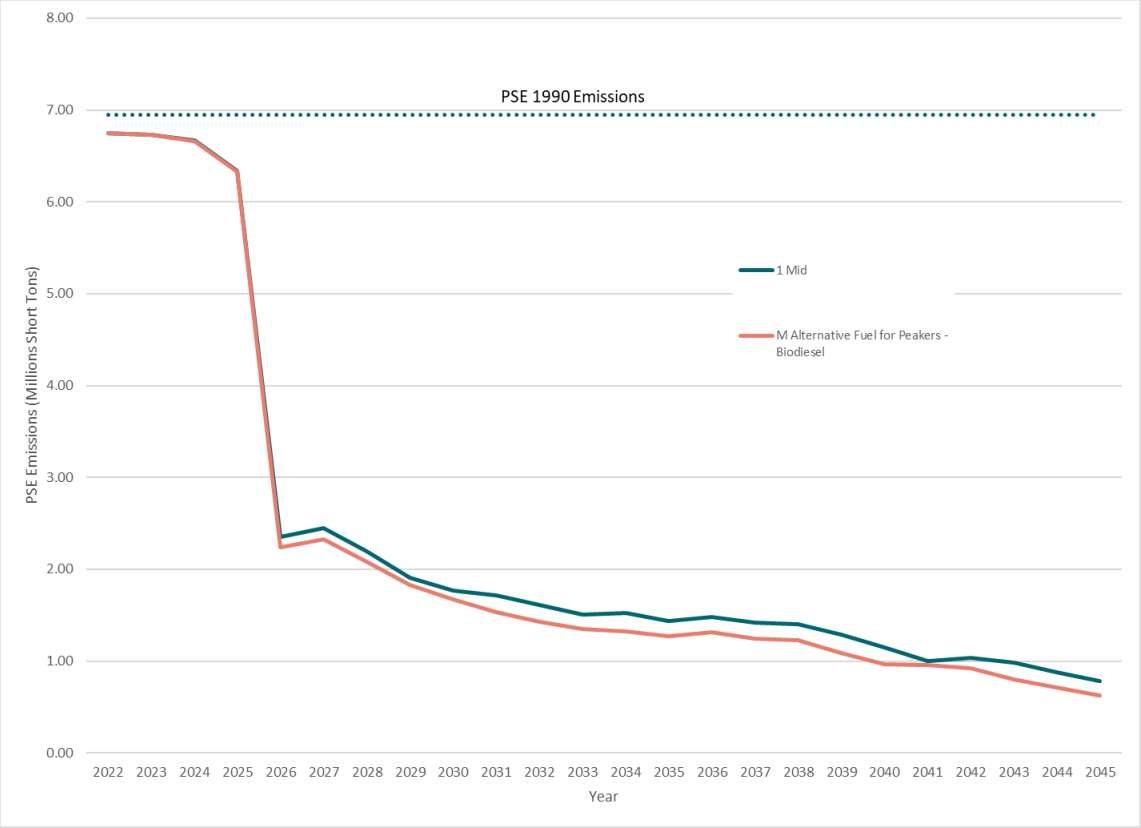


Figure 8-79: Portfolio Additions by 2045 – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers

Resource Additions by 2045	1. Mid	M. Alternative Fuel for Peakers
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	700 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	185 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,818 MW
Biomass	90 MW	75 MW
Solar	1,393 MW	1,593 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

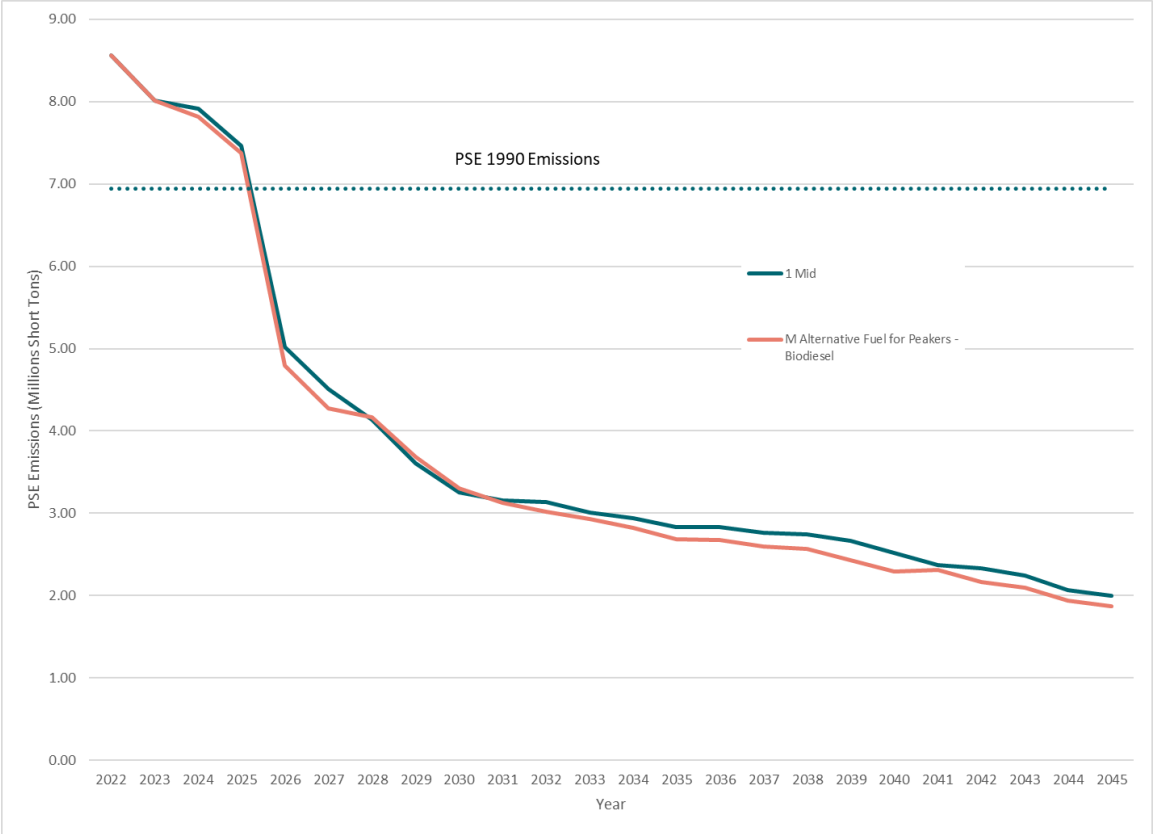
EMISSIONS. Sensitivity M resulted in fewer direct GHG emissions compared to the Mid Scenario due to the use of a carbon neutral fuel for peaking capacity needs. Figure 8-80 compares the GHG emissions from the Mid Scenario and Sensitivity M portfolios. Following acquisition of the first peaking capacity resource in 2026, Sensitivity M has consistently lower GHG emissions over the course of the modeling horizon.

Figure 8-80: Direct GHG Emissions – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers



A similar trend is observed in Figure 8-81 which compares GHG emissions from the Sensitivity M with the Mid Scenario emissions, including both direct and indirect (i.e. market) emissions. Sensitivity M maintains lower emissions, however, the difference in emission reductions between the two portfolios is smaller.

Figure 8-81: Direct and Indirect GHG Emissions– Mid Scenario and Sensitivity M



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

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

Figure 8-82 shows the results of this calculation for Sensitivity M and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. Sensitivity M is very efficient a reducing portfolio emissions; this is why biodiesel was added a fuel to the preferred portfolio.

Figure 8-82: Cost of Emissions Reduction – Mid Scenario, Sensitivity M and Sensitivity W (the Preferred Portfolio)

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
M Alternative Fuel for Peakers	52.84	$15.53	<0.01
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

CAPACITY FACTOR. Despite the much higher cost of biodiesel ($30.53/MMBtu) as compared to natural gas ($3.56/MMBtu), the overall revenue requirement of Sensitivity M and the Mid Scenario are roughly equal. This is because the high cost of biodiesel drives down the dispatch frequency of the new frame peaking resources. New frame peakers in the Mid Scenario had an annual capacity factor of about 3 percent in the year 2045. In Sensitivity M, the annual capacity factor of new frame peakers dropped to less than 0.1 percent. This suggests that the frame peakers were only dispatched in periods of peak demand to fill a specific role in providing peak capacity to the portfolio.

BIODIESEL AVAILABILITY. When modeling a portfolio like Sensitivity M that relies on a limited commodity such as biodiesel, it is important to consider the availability of that resource. Washington state produced around 114 million gallons of biodiesel in 2019 from two facilities.[5] In Sensitivity M, biodiesel fueled frame peakers supplied, at most, 7,233 MWh of energy over the modeling horizon. This equates to an annual need of approximately 600,000 gallons of biodiesel or about 0.5 percent of Washington State's annual production. This relationship suggests that the Washington biodiesel market could plausibly support the use of biodiesel for peak need electricity generation. PSE also evaluated the fuel needed to maintain resource adequacy which is included in Chapter 7.

5 / https://www.eia.gov/biofuels/biodiesel/production/

N. 100% Renewable by 2030

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that advances the CETA target of 100 percent renewable energy to 2030.

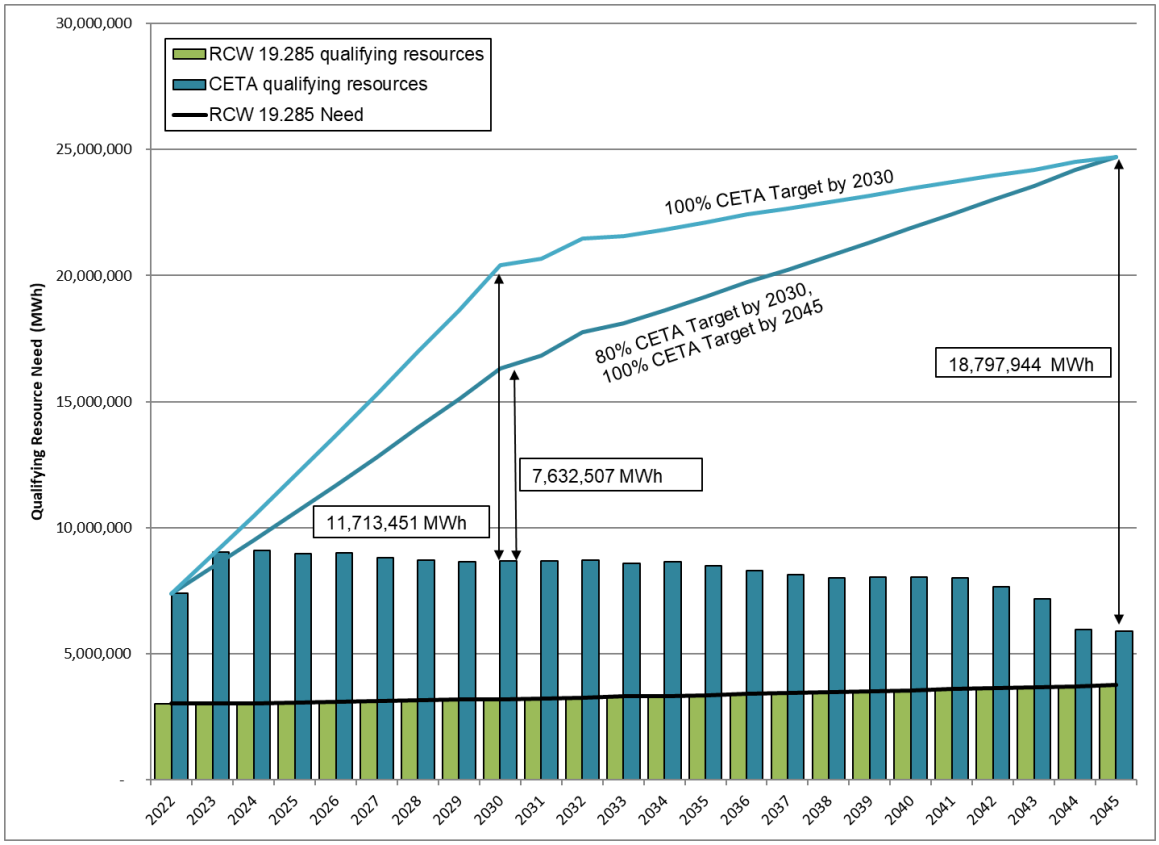
Baseline: 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.
Sensitivity > 100 percent of sales must be met by non-emitting/renewable resources by 2030.

KEY FINDINGS. Sensitivity N demonstrates that achieving a 100 percent renewable portfolio is possible with existing technologies, but the cost to do so is unrealistically high. The 24-year levelized portfolio cost of Sensitivity N is $15.17 and $33.37 billion more than the Mid Scenario for variations N1 and N2 respectively. The resource additions responsible for these higher portfolio costs do provide a benefit to overall portfolio emissions, but the efficiency of these emissions reductions per dollar spent are extremely low.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales are met by non-emitting/renewable resources by 2030, ramping up to 100 percent by 2045. Existing thermal plants continue to be in operation unless economically retired by the model. New peaking capacity resources remain an option for new resource selection. In order for the Mid Scenario portfolio to be 100 percent greenhouse gas neutral by 2030, an estimate for alternative compliance costs is calculated starting in 2030 through 2044. In Sensitivity N, all existing thermal plants are retired by 2030 regardless of economic viability. New peaking capacity resources are also removed for new resource selection. The CETA target is adjusted to 100 percent renewable by 2030. This means the renewable energy target increases by 4.1 million MWhs, rising from 7.6 million MWhs in 2030 to 11.7 million MWhs as shown in Figure 8-70.

Sensitivity N modeled two slightly different sets of assumptions. The first iteration, Sensitivity N1, used the model constraints provided above. Sensitivity N1 allowed the portfolio model to optimize to the 100 percent CETA target by 2030 by whatever means necessary. The second iteration, Sensitivity N2, removed lithium-ion and flow batteries from the available resources. Sensitivity N2 forced the model to solve using pumped hydro storage as the primary storage technology.

Figure 8-83: Renewable Targets – Mid Scenario and Sensitivity N1 and N2 Portfolios

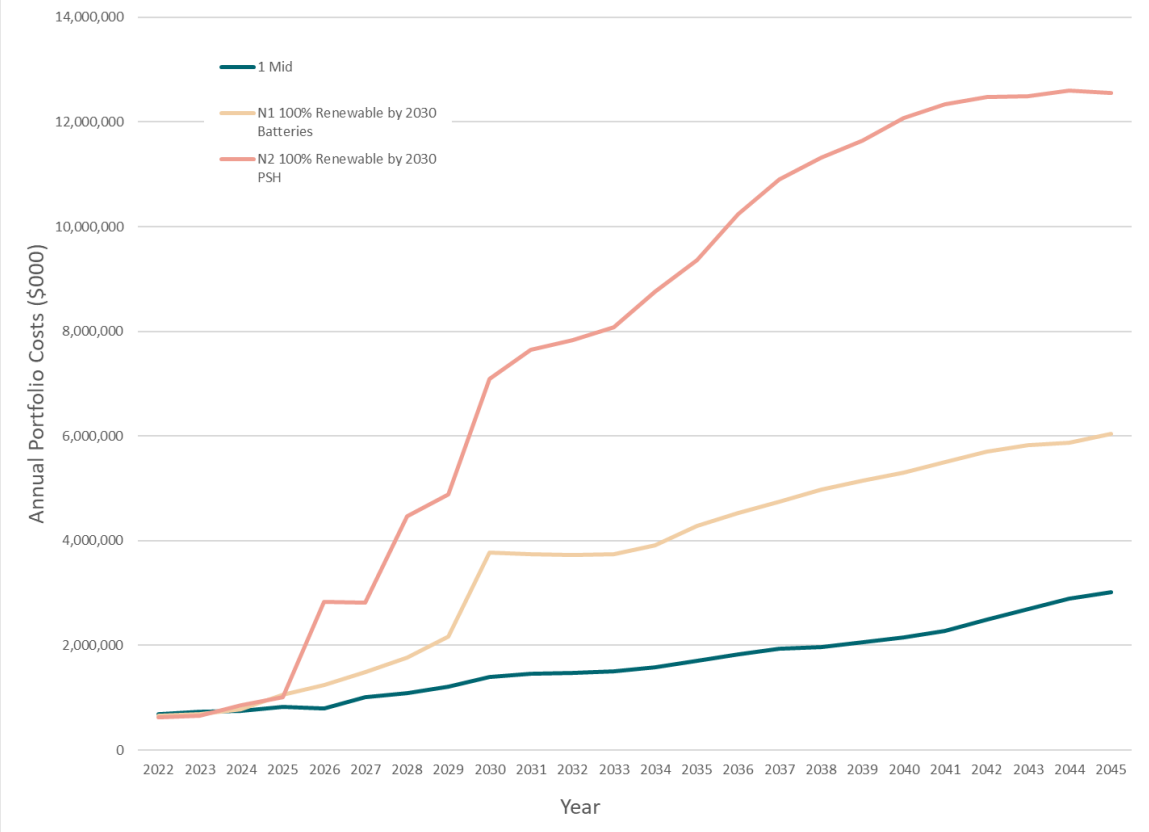


PORTFOLIO COSTS. Sensitivity N demonstrates that aggressively meeting CETA targets ahead of schedule may be possible with existing technologies, but that the cost to do so is high. The increase in costs for Sensitivity N is due to the increase in overall resource builds, particularly for storage resources. Both variations of Sensitivity N have lower SCGHG compared to the Mid Scenario; however, both variations also are among the most expensive portfolios modeled as part in the 2021 IRP. Figures 8-84 and 8-85 compare the breakdown of costs between the Mid Scenario and Sensitivity N portfolios.

Figure 8-84: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N1 and N2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
N1	100% Renewable by 2030 (Batteries)	$32.03	$3.76	$35.79	$15.17
N2	100% Renewable by 2030 (PHES)	$66.64	$2.52	$69.16	$33.37

Figure 8-85: Annual Portfolio Costs – Mid Scenario and Sensitivity N1 and N2



RESOURCE ADDITIONS. Figures 8-86 and 8-87 compare the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. By 2025, Sensitivity N1 has built a large amount of wind and Sensitivity N2 has built a large amount of solar (both standalone and hybrid) to replace the energy from retirements of Colstrip and Centralia, as well as to meet the high CETA renewable need. Through 2030, Sensitivity N1 selects a portfolio composed largely of 2-hour lithium-ion batteries and wind, whereas Sensitivity N2 selects a more diversified set of resources, adding pumped hydro as a storage resource and a mix of solar and wind projects. At the end of planning period, storage resources compose 78 percent and 71 percent of the resource capacity for Sensitivities N1 and N2 respectively. These massive investments in storage dwarf the resource additions selected in the Mid Scenario, resulting in exorbitant portfolio costs.

Figure 8-86: Portfolio Additions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

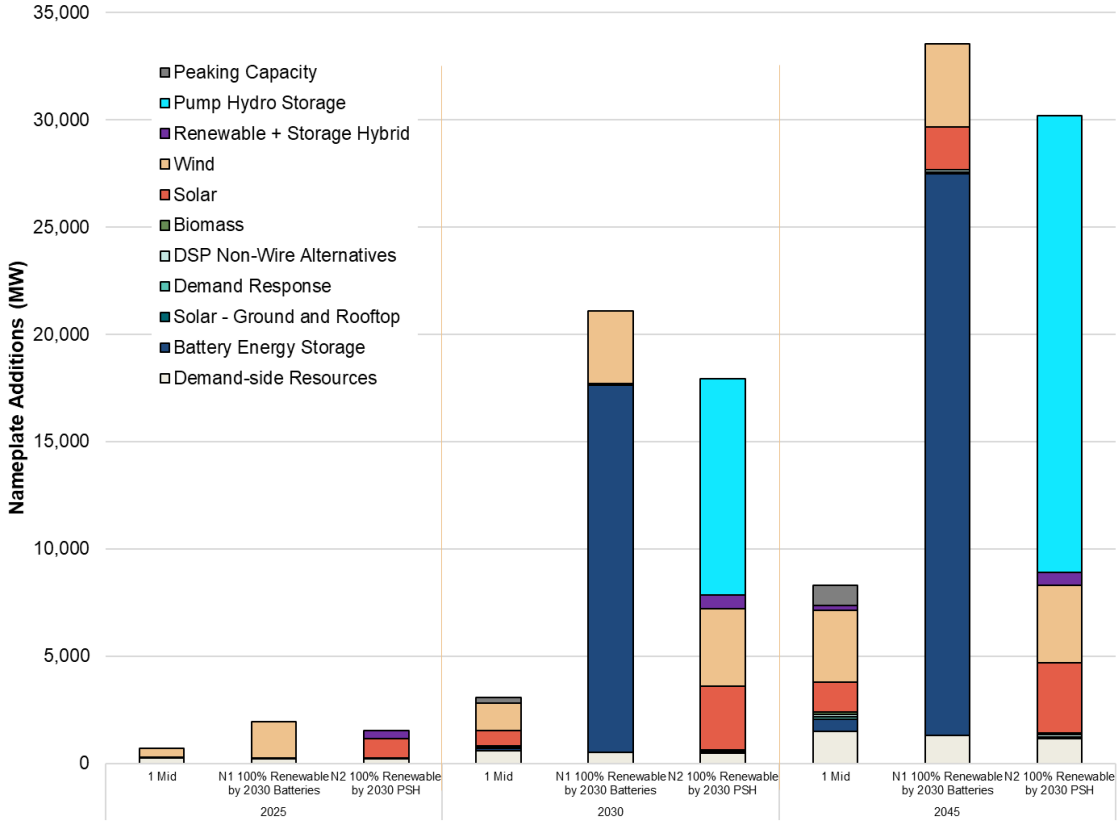


Figure 8-87: Portfolio Additions by 2045 – Sensitivity N, 100% Renewable by 2030

Resource Additions by 2045	1 Mid	N1 100% Renewable by 2030 - Batteries	N12100% Renewable by 2030 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,169 MW
Battery Energy Storage	550 MW	26,200 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	59 MW	59 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,844 MW	6,943 MW
Biomass	90 MW	0 MW	75 MW
Solar	1,393 MW	1,994 MW	3,268 MW
Wind	3,350 MW	3,850 MW	3,600 MW
Renewable + Storage Hybrid	250 MW	0 MW	622 MW
Pumped Hydro Storage	0 MW	0 MW	21,300 MW
Peaking Capacity	948 MW	0 MW	0 MW

EMISSIONS. Figure 8-88 compares the direct GHG emissions from the Sensitivity N variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2030, the emissions for Sensitivity N drop to zero at 2030. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able to charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-88: Direct GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

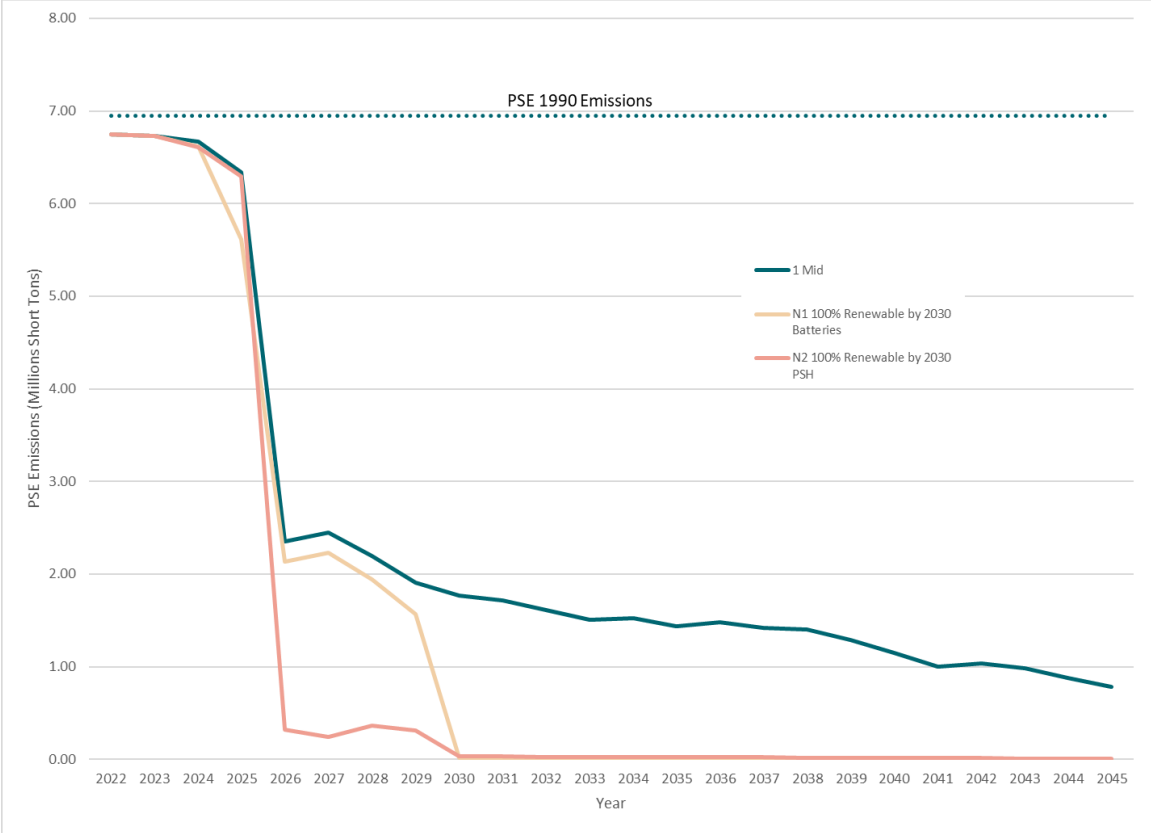
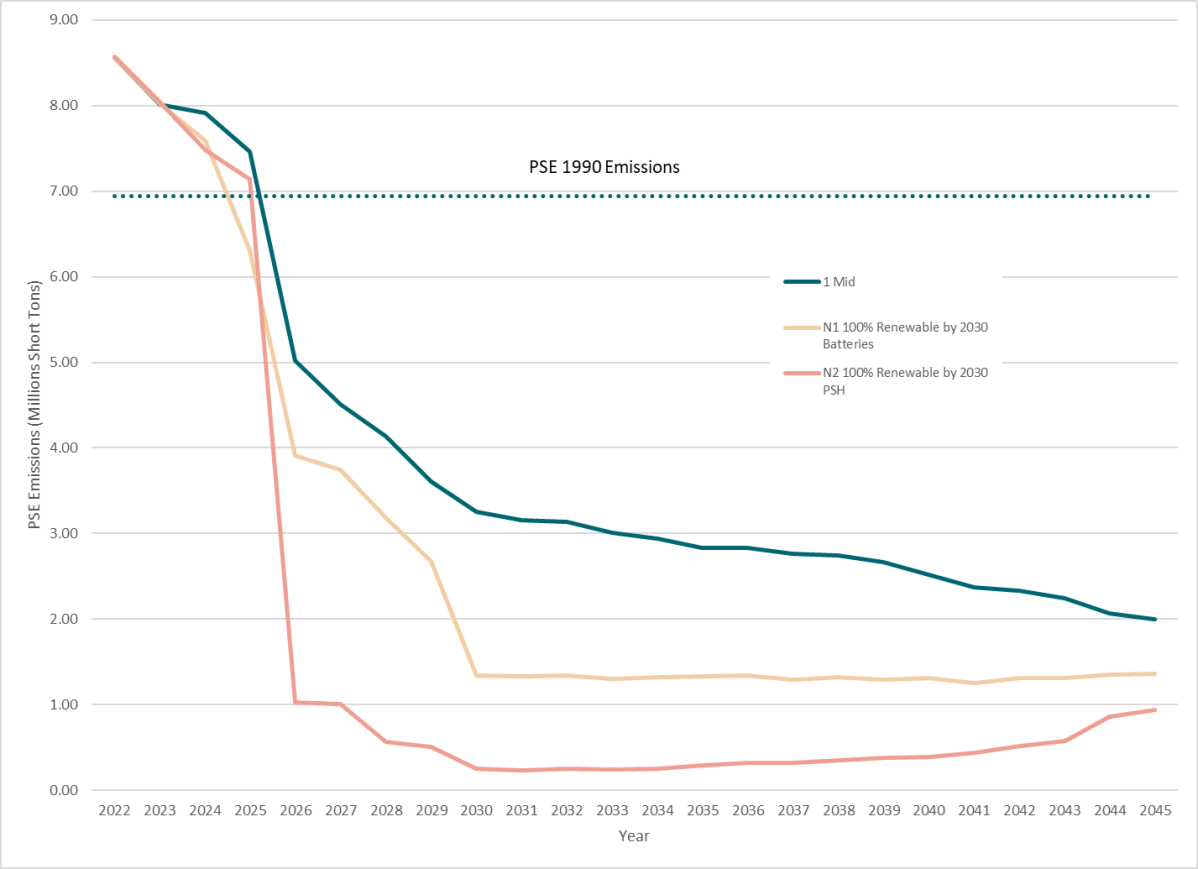


Figure 8-89 compares GHG emissions from the Sensitivity N1 and N2 variations with the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity N emissions are lower than Mid Scenario emissions throughout the planning horizon, but it is interesting to note that emissions start to increase again for both Sensitivities N1 and N2 in the later years of the planning period due to the increase in energy purchased from market to fill the growing demand from storage resources.

Figure 8-89: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030



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

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

Figure 8-90 shows the results of this calculation for the Sensitivity N variations and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity N variations are an order of magnitude higher than the preferred portfolio, which suggests that forcing 100 percent renewable energy by 2030 is not an efficient means to reduce emissions.

Figure 8-90: Cost of Emissions Reduction – Mid Scenario, Sensitivity N and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

O. 100% Renewable by 2045

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that has no natural gas-fired generation resources by 2045.

Baseline: No planned retirements of existing gas fired generation resources; however, the model allows for economic retirement.
Sensitivity > All existing natural gas-fired resources, including new peaking capacity resources, must be retired by 2045.

KEY FINDINGS. Sensitivity O shows that it is possible to phase out natural gas generation by the year 2045. However, the capital cost to do so it very high. On the basis of tons of GHG emissions reduced per dollar, there are more efficient ways to achieve comparable emissions reductions. Sensitivity O also shows the importance of market purchases to supporting a storage-heavy portfolio in a cost-effective manner.

ASSUMPTIONS. In the Mid Scenario portfolio, existing natural gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource, but they retire by 2045. In Sensitivity O, all existing natural gas-fired generation resources are retired by 2045, regardless of economic viability. Existing thermal plant retirements are ramped in over time at a rate of approximately 200 MW per year between 2030 and 2045 to create a smoother transition to renewable generation.

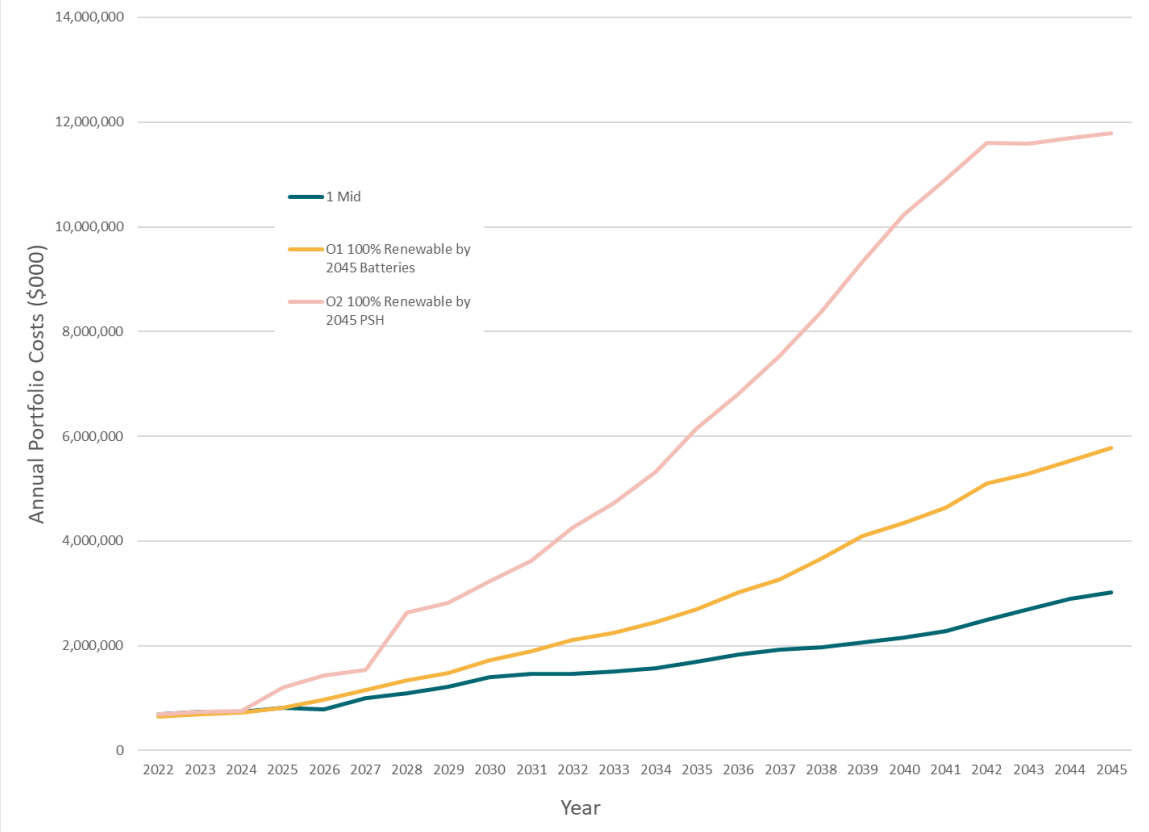
Sensitivity O modeled three slightly different sets of assumptions. The first iteration, Sensitivity O1, used the model constraints provided above and allowed the model to optimize removing natural gas fueled resource by 2045. The second iteration, Sensitivity O2, removed lithium-ion and flow batteries from the list of available resources and forced the model to solve using pumped hydroelectric storage as the primary storage technology.

PORTFOLIO COSTS. Figures 8-91 and 8-92 illustrate the breakdown of costs between the Mid Scenario and Sensitivity O portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds.

Figure 8-91: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity O1 and Sensitivity O2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
O1	100% Renewable by 2045 – Batteries	$23.35	$4.81	$28.16	$7.54
O2	100% Renewable by 2045 – PHES	$46.95	$3.98	$50.94	$30.32

Figure 8-92: Annual Portfolio Costs – Mid Scenario and Sensitivity O



RESOURCE ADDITIONS. Figures 8-93 and 8-94 compare the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. Neither variation of Sensitivity O selects any flexible capacity resources over the course of the planning period. Both variations focus on building storage resources early and often to keep up with growing capacity need. Sensitivity O1 builds solely standalone 2-hour lithium-ion batteries, whereas Sensitivity O2 builds a mix of pumped hydroelectric storage and hybrid resources. Both variations rely heavily on market purchases to charge storage resources throughout the planning period.

Figure 8-93: Portfolio Additions – Mid Scenario and Sensitivity O

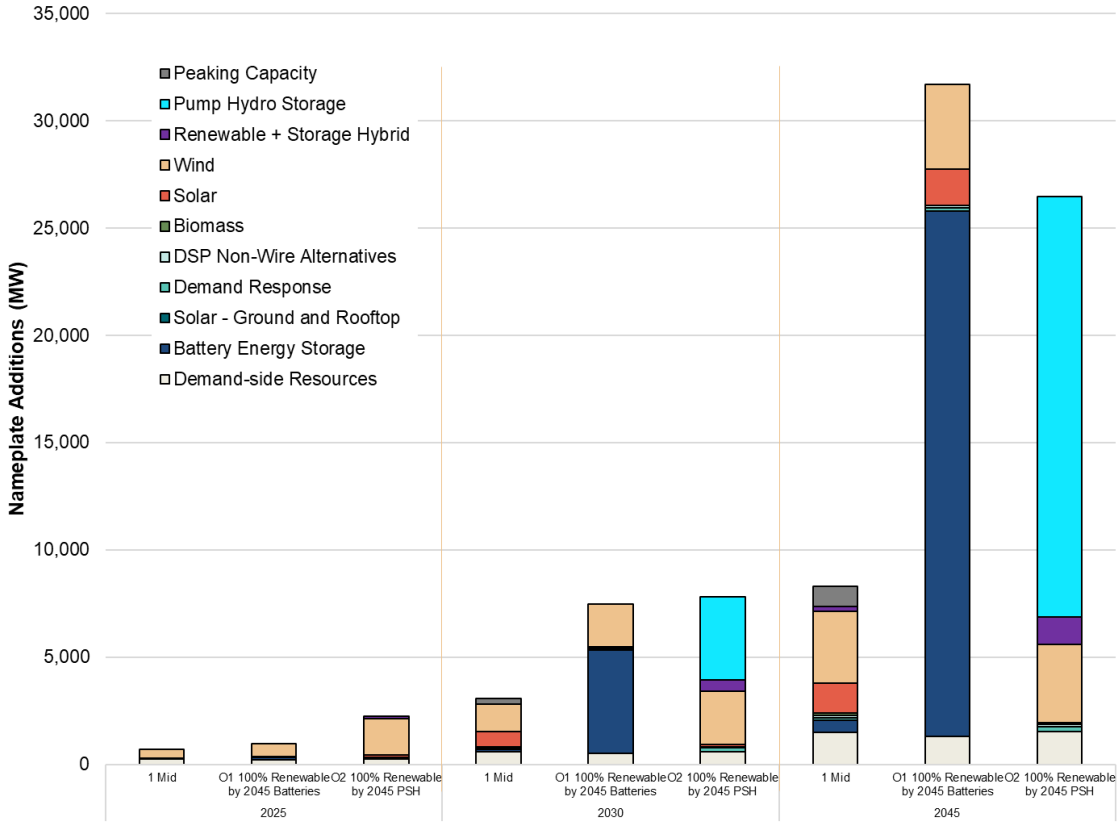


Figure 8-94: Portfolio Additions by 2045 – Mid Scenario and Sensitivity O, – 100% Renewable by 2045

Resource Additions by 2045	1 Mid	O1 100% Renewable by 2045 - Batteries	O2 100% Renewable by 2045 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,537 MW
Battery Energy Storage	550 MW	24,500 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	128 MW	204 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,642 MW	3,749 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	1,692 MW	99 MW
Wind	3,350 MW	3,950 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	0 MW	1,249 MW
Pumped Hydro Storage	0 MW	0 MW	19,600 MW
Peaking Capacity	948 MW	0 MW	0 MW

PEAK CAPACITY. The results of Sensitivity O are somewhat conflicted. On one hand, Sensitivity O1 just barely exceeds the peak capacity need in the year 2045 as shown in Figure 8-95. On the other hand, Sensitivity O2 was significantly over-built, exceeding peak need by over 5,000 MW in 2045 as shown in Figure 8-83. These two extremes make the results difficult to interpret with confidence. It seems unlikely that many small 2-hour storage resources are the most effective resources to meet peak need without the aid of thermal resources. However, Sensitivity O1 was far less costly than Sensitivity O2, which included seemingly more flexible 8-hr storage resources. Sensitivity O placed extreme demands on the simulation to dispatch over 10,000 MW of storage capacity and to replace over 2,000 MW of existing thermal resources in a single year. More work is required to refine storage logic within the portfolio model.

Figure 8-95: Peak Capacity Contribution – Mid Scenario and Sensitivity O1, 100% Renewable by 2045 – Batteries

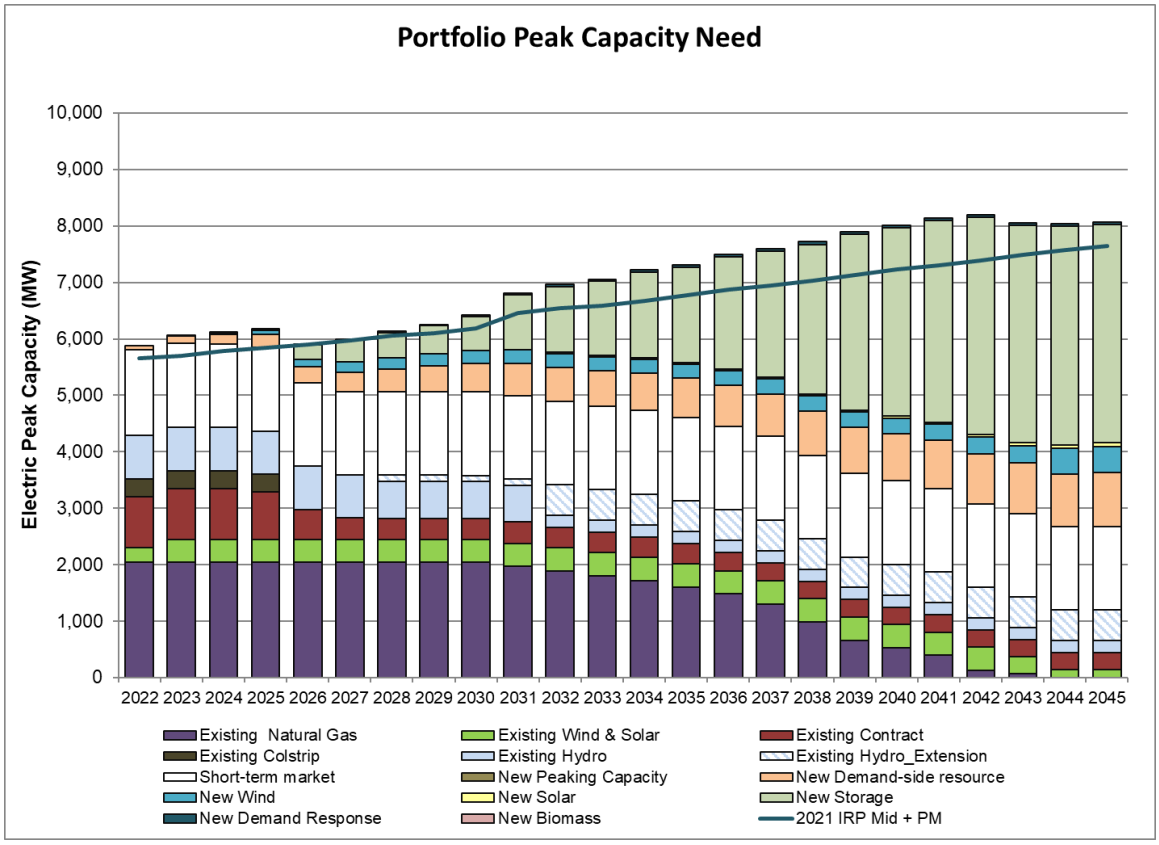
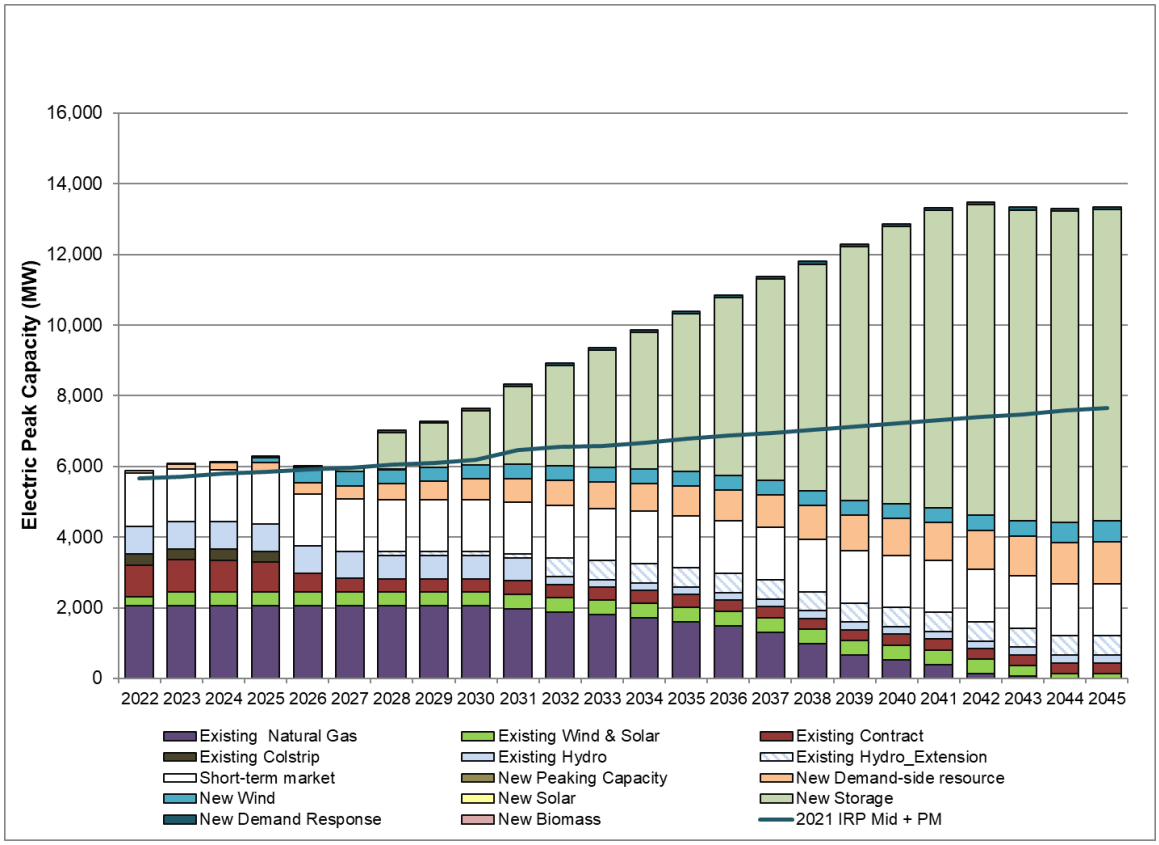


Figure 8-96: Peak Capacity Contribution – Mid Scenario and Sensitivity O2 – 100% Renewable by 2045 – Pumped Hydro Storage



EMISSIONS. Figure 8-97 compares the direct GHG emissions from the Sensitivity O variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2045, the emissions for Sensitivity O drop to zero by 2045. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-97: Direct GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045

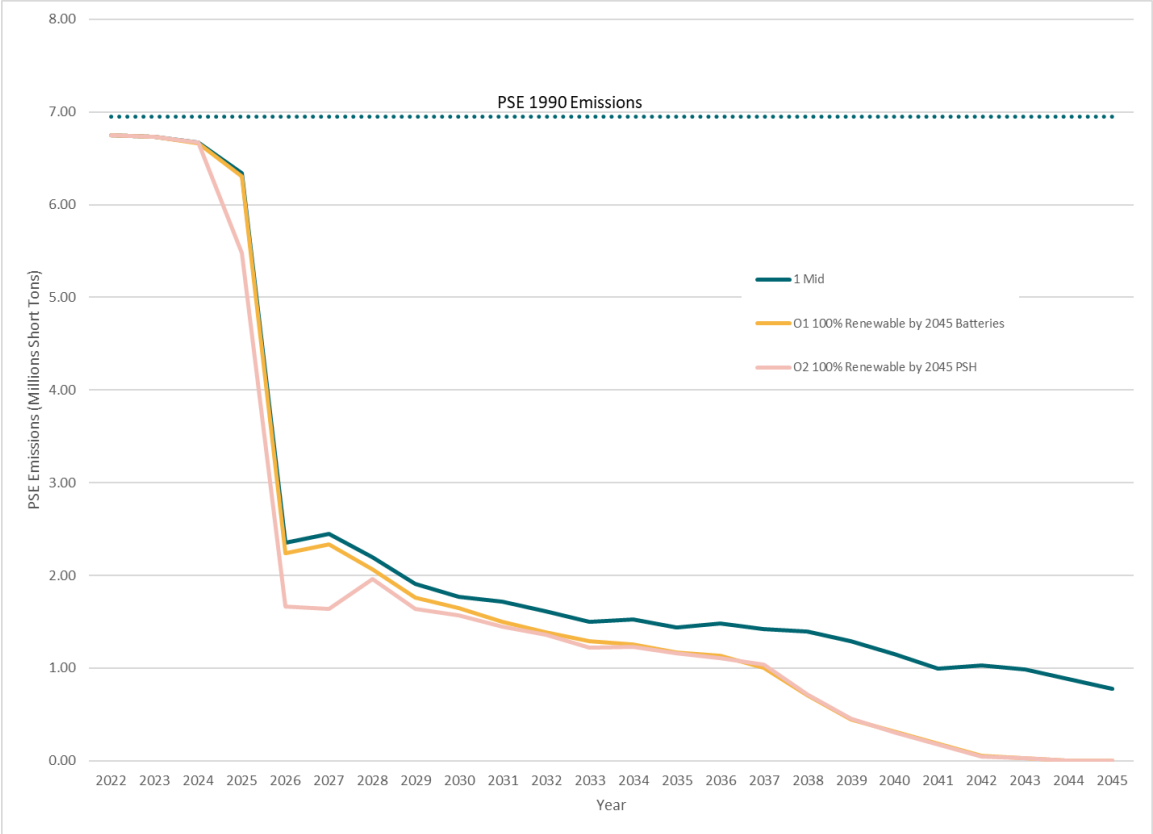


Figure 8-98 provides a view of GHG emissions from the Sensitivity O variations compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity O emissions are still lower than Mid Scenario emissions throughout the planning horizon.

Figure 8-98: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045



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

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

Figure 8-99 shows the results of this calculation for Sensitivity O and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity O variations are an order of magnitude larger than the preferred portfolio, suggesting that forcing out natural gas generation is not an efficient means to reduce emissions.

Figure 8-99: Cost of Emissions Reduction – Mid Scenario, Sensitivity O and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
O1 100% Renewable by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Renewable by 2045 - PHES	43.54	$46.95	3.04
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

P. No New Thermal Resources Before 2030

This sensitivity provides insight into how energy storage provides value to a system that has traditionally been provided by natural gas plants.

Baseline: Thermal peaking capacity resources may be added to the portfolio as early as 2025**.** **Sensitivity P >** No thermal peaking capacity may be added to the portfolio until 2030, thereby requiring the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need.

KEY FINDINGS. In Sensitivity P, delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources and the addition of fewer peaking capacity resources. However, these changes increased portfolio costs by $7 to $25 billion depending on the type of storage resource selected. Furthermore, Sensitivities P1 and P3 showed no reduction in GHG emissions compared to the Mid Scenario. Sensitivity P2 did show a small reduction in GHG emissions, but the emission reduction efficiency was quite low compared to other portfolios such as the preferred portfolio.

ASSUMPTIONS. In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In Sensitivity P, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection of energy storage, renewable resources and demand-side resources to keep the portfolio balanced until peaking capacity resources are available.

To gain an understanding of how the model reacts to different storage resources, three variations on Sensitivity P were run. Sensitivity P1 used the model constraints described above and allowed the model to select the most cost-effective storage resource in the period 2022 to 2030; the

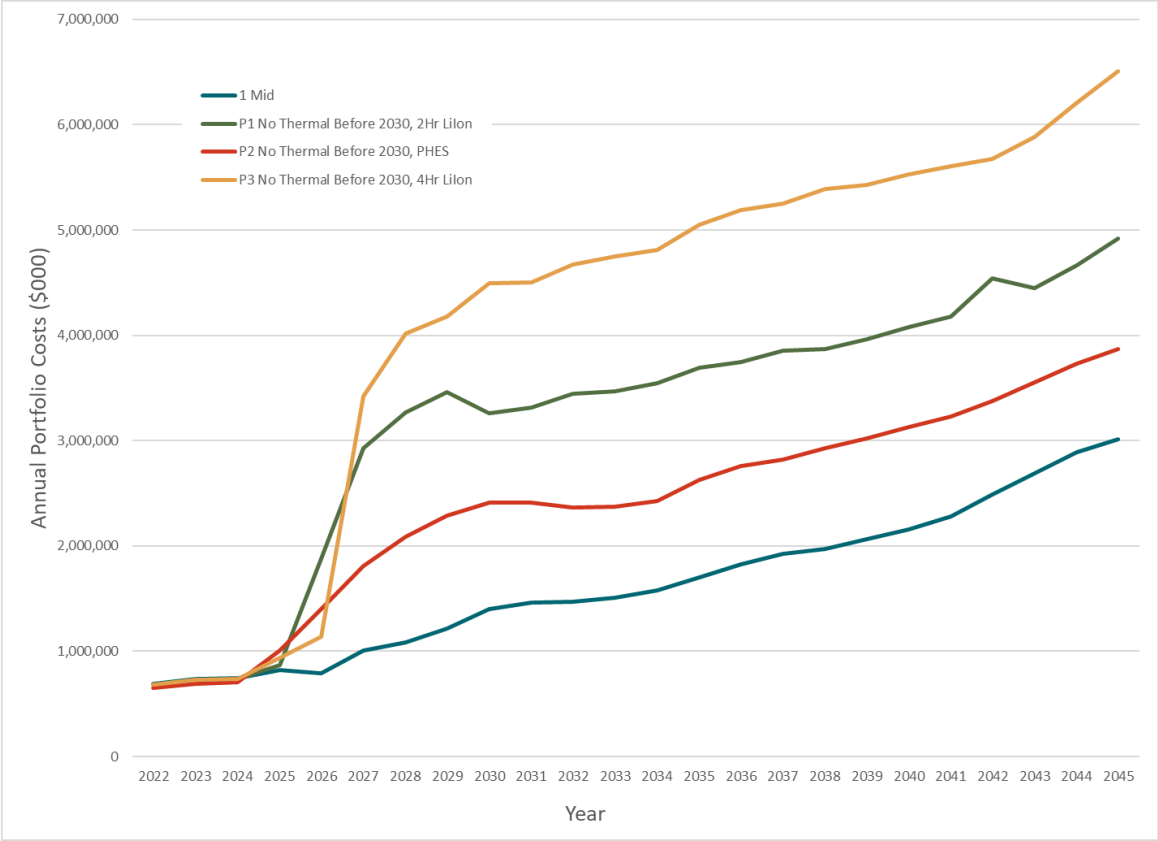
model selected 2-hour lithium-ion batteries. Sensitivity P2 removed lithium-ion and flow batteries from the list of available resources before 2030 and forced the model to solve using pumped hydroelectric storage as the primary storage technology. Sensitivity P3 removed 2-hour lithium-ion batteries from the available resources before 2030, and forced the model to select the next most cost-effective storage resource to meet capacity need before 2030; then the model selected 4-hour lithium-ion batteries.

PORTFOLIO COSTS. Figures 8-100 and 8-101 illustrate the breakdown of costs between the Mid Scenario and Sensitivities P1, P2 and P3. Annual portfolio costs are significantly higher for all variations of Sensitivity P compared to the Mid Scenario. Storage resources and demand response programs are more expensive options than peaking capacity resources. All variations of Sensitivity P added over 2,500 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pumped hydro energy storage was added to both portfolios between 2025 and 2030 causing the spike in annual portfolio costs.

Figure 8-100: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity P

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
P1	No New Thermal Resources – 2-hr Li-Ion	$30.84	$6.38	$37.22	$16.60
P2	No New Thermal Resources – PHES	$22.85	$4.77	$27.62	$7.00
P3	No New Thermal Resources – 4-hr Li-Ion	$39.01	$6.69	$45.70	$25.08

Figure 8-101: Annual Portfolio Costs – Mid Scenario and Sensitivity P



RESOURCE ADDITIONS. Figures 8-102 and 8-103 compare the nameplate capacity additions of the portfolios in Sensitivities P1, P2 and P3 and the Mid Scenario. The Mid Scenario portfolio added 237 MW of peaking capacity resources in 2026 as Colstrip and Centralia were removed. It would take about 3,800 MW nameplate capacity of batteries to equal those new peaking capacity resources since 2-hour lithium-ion batteries have only a 12.4 percent ELCC. Sensitivity P1 selected 3,775 MW of 2-hour lithium-ion batteries to make up for the absence of new peaking capacity resources. Similar resources are added in the other variations of Sensitivity P, the only difference being the addition of alternative storage resources (pumped hydroelectric storage and 4-hour lithium-ion batteries).

All three Sensitivity P portfolios added a significant amount of 2-hour lithium-ion battery resources. Sensitivity P1 selected 2-hour lithium-ion batteries as the most cost-effective resource and built nearly exclusively 2-hour lithium ion batteries, except for 25 MW of 4-hour lithium-ion batteries in the year 2045. Sensitivity P2 was forced to select pumped hydro storage as the initial storage technology; after 2030, no new pumped hydro storage was added, but 1,025 MW of 2-hour lithium-ion batteries were added. Similarly, Sensitivity P3 was forced to select 4-hour lithium-

ion batteries as the initial storage technology; after 2030 no new 4-hour batteries were added, but 875 MW of 2-hour lithium-ion batteries were added to the portfolio.

By the end of the planning period, Sensitivity P1 had built 474 MW of peaking capacity, about half of the peaking capacity selected in the Mid Scenario. The large capacity storage resources (PHES and 4-hour lithium-ion batteries) built far less peaking capacity, with Sensitivity P2 building only 18 MW of peaking capacity and Sensitivity P3 building none at all.

Figure 8-102: Portfolio Additions – Mid Scenario and Sensitivity P

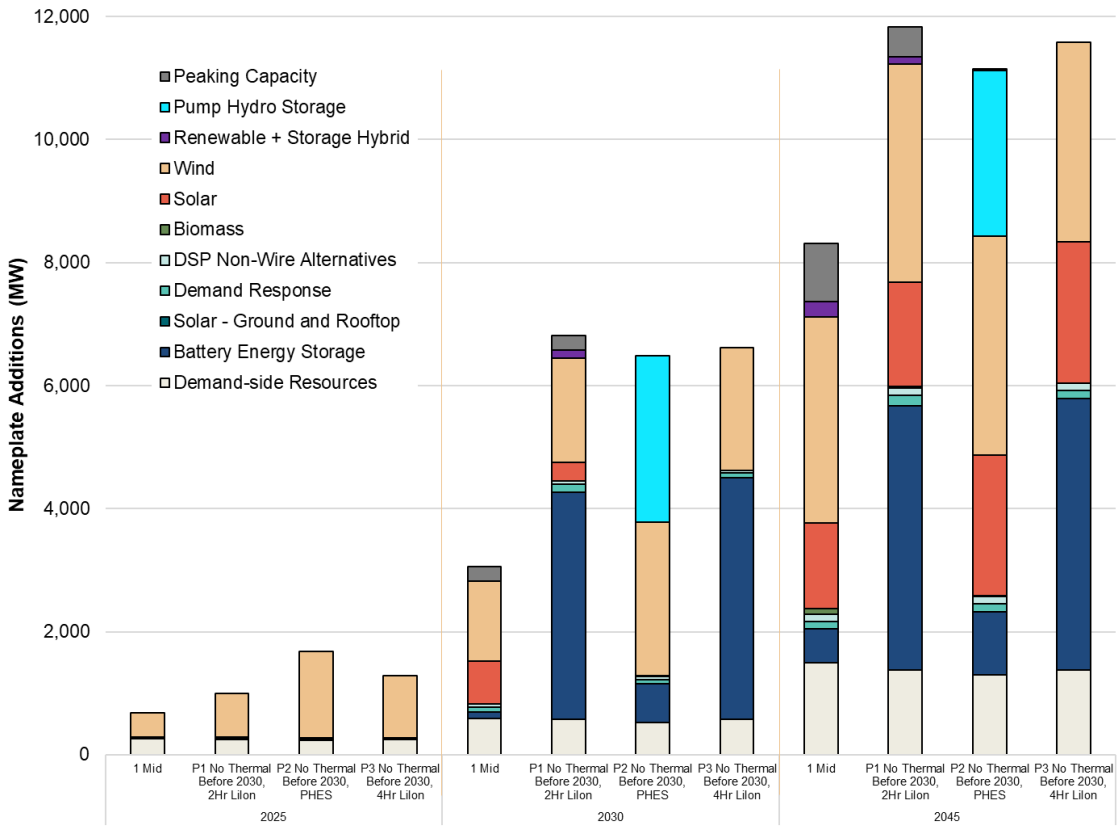
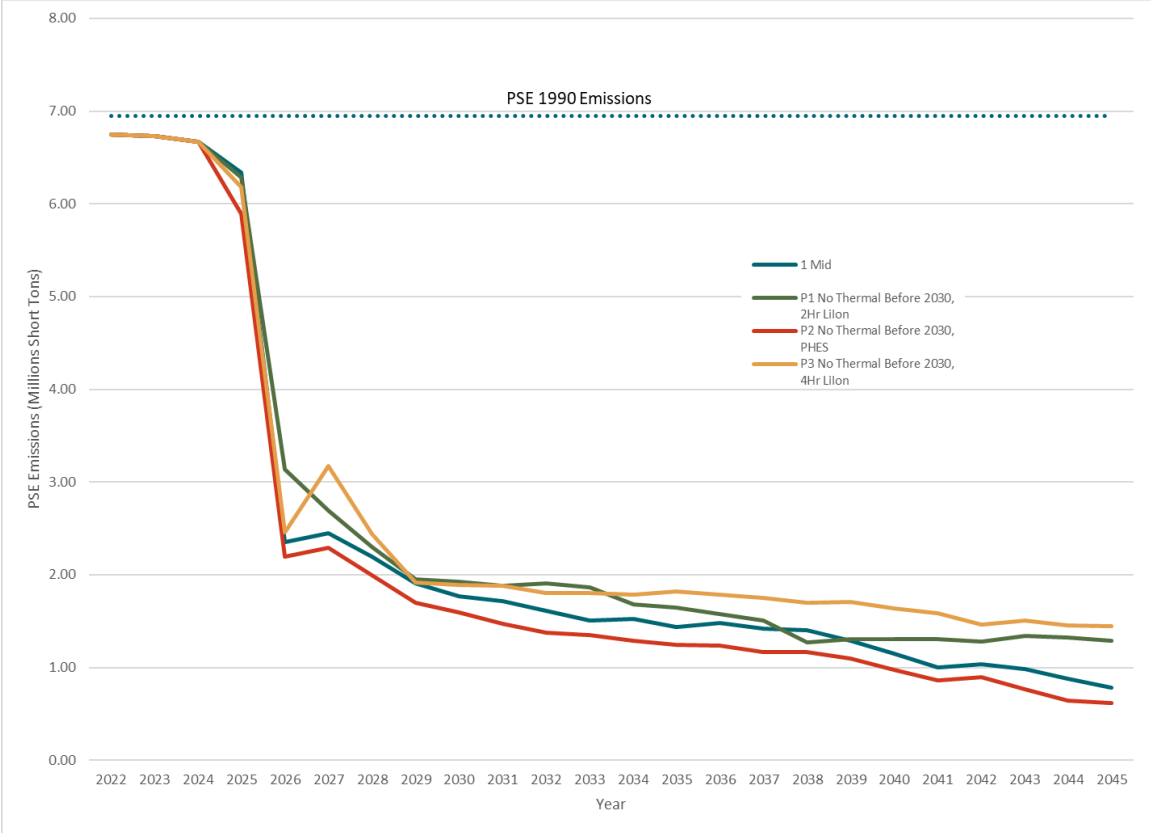


Figure 8-103: Portfolio Additions by 2045 – Mid Scenario and Sensitivity P, No New Thermal Before 2030

Resource Additions by 2045	1 Mid	P1 No New Thermal – 2hr Li-Ion	P2 No New Thermal – PHES	P3 No New Thermal – 4hr Li-Ion
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,372 MW
Battery Energy Storage	550 MW	4,300 MW	1,025 MW	4,425 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	178 MW	122 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,260 MW	5,859 MW	5,542 MW
Biomass	90 MW	15 MW	15 MW	0 MW
Solar	1,393 MW	1,695 MW	2,294 MW	2,292 MW
Wind	3,350 MW	3,550 MW	3,550 MW	3,250 MW
Renewable + Storage Hybrid	250 MW	125 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	2,700 MW	0 MW
Peaking Capacity	948 MW	474 MW	18 MW	0 MW

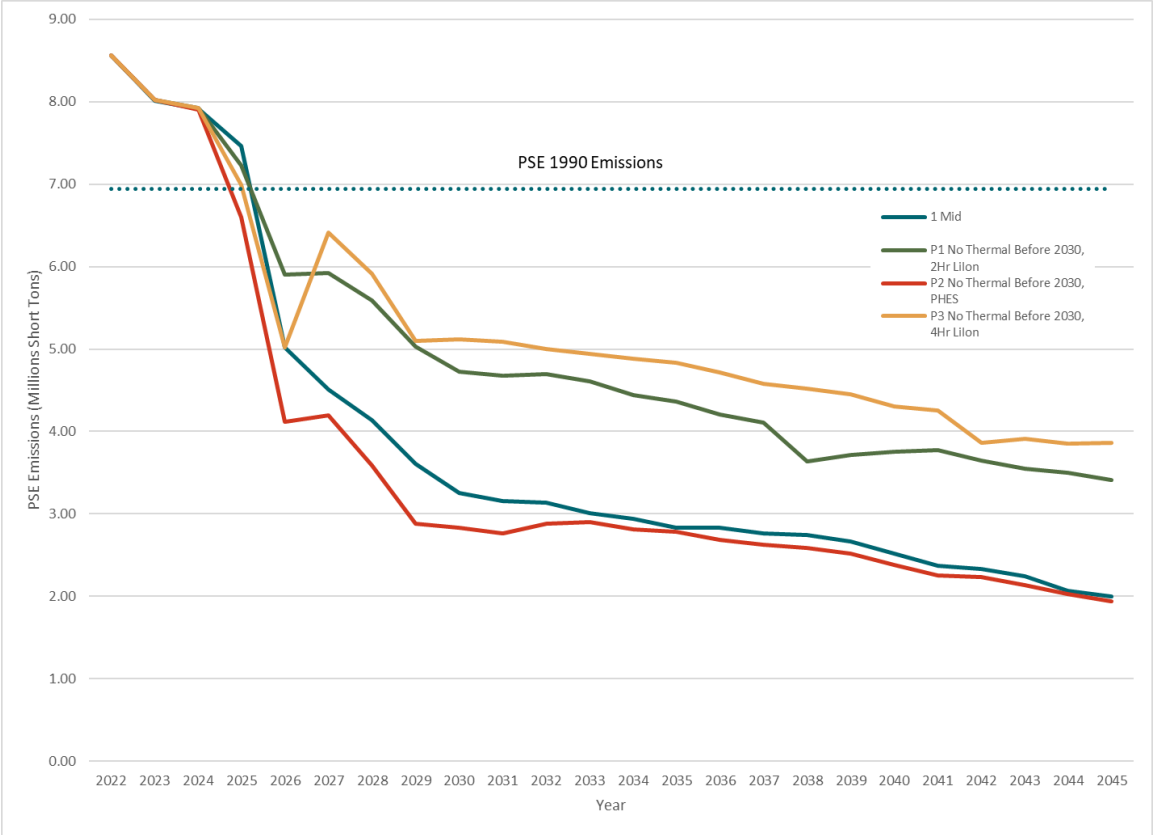
OTHER FINDINGS. Figure 8-104 compares the direct GHG emissions from the Sensitivity P variations with to the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Despite fewer peaking capacity resources built over the planning period, Sensitivities P1 and P3 have higher direct GHG emissions compared to the Mid Scenario due increased dispatch of existing thermal resources over the planning period. Existing thermal resources are not as efficient as new peaking resources and therefore generate greater emissions.

Figure 8-104: Direct GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



When storage is a major component of a resource portfolio, indirect emissions from market purchases increase. Storage resources may charge from market purchases and these unspecified market purchases are tagged with a GHG emission rate per CETA rules. Figure 8-105 provides a view of GHG emissions from the Sensitivity P variations as compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivities P1 and P3 are now significantly higher emitters than the Mid Scenario, and Sensitivity P3 has nearly the same emission rate as the Mid Scenario. The increase in emissions from portfolios P1 and P3 comes from an increase in dispatch from the existing natural gas resources.

Figure 8-105: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



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

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

Figure 8-106 shows the results of this calculation for Sensitivity P and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. For Sensitivities P1 and P3, both the cost of the portfolio and the levelized quantity emissions were greater than the Mid Scenario, which by definition means they are not feasible plans for reducing emissions. Sensitivity P2 did result in a small reduction in emissions, but the cost of emissions reduction is much higher than in the preferred portfolio, suggesting that replacing the new peaker with storage is not an effective means to reduce emissions.

Figure 8-106: Cost of Emissions Reduction – Mid Scenario, Sensitivity P and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

Demand Forecast Adjustments

Q. Fuel Switching, Gas to Electric

Natural gas is often used for space heating, water heating, cooking, industrial process heat and feedstocks and other uses in residential, commercial and industrial settings. Recent trends in local legislation limit the use of natural gas for these purposes in new construction. Sensitivity Q explores how the energy environment may change if electricity was used as an energy supply in place of the current uses of natural gas.

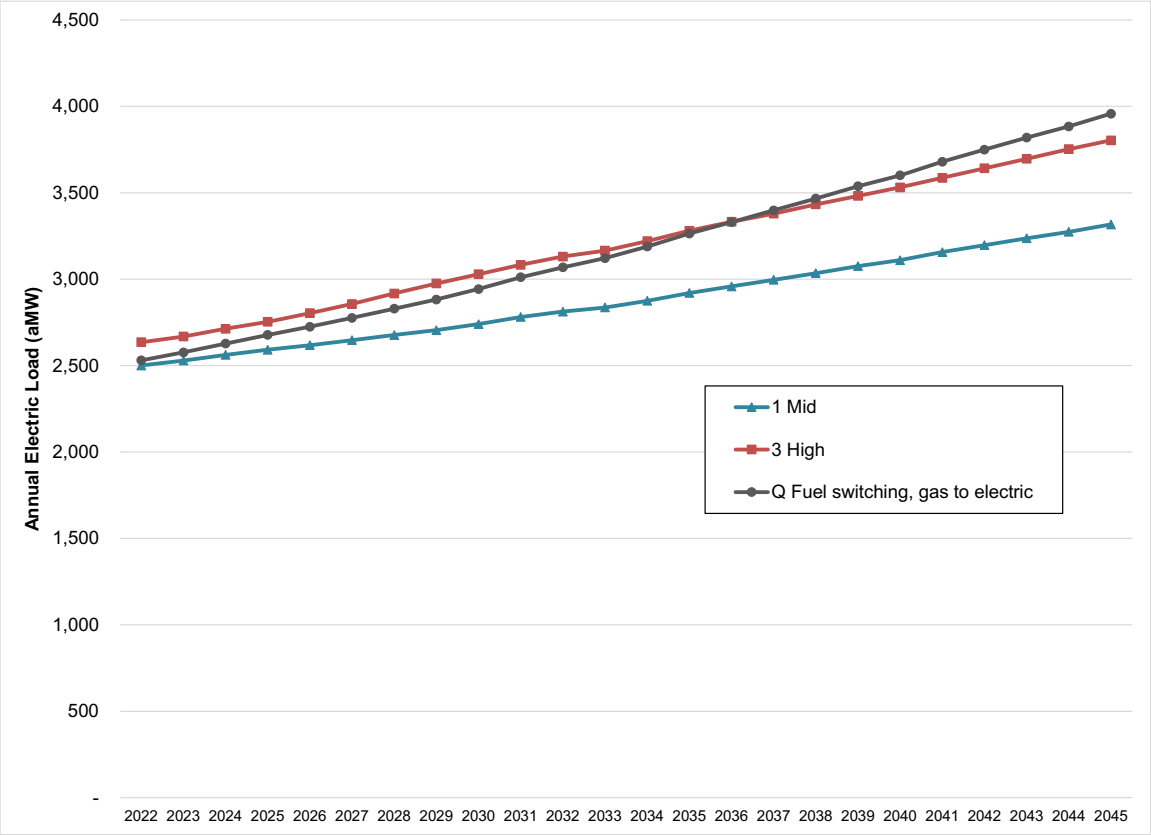
Baseline: The Mid Scenario assumes the IRP Base Demand Forecast.
Sensitivity R > Sensitivity Q modifies the demand forecast to simulate substitution of electricity for current uses of natural gas in PSE's service area.

KEY FINDINGS. Incorporating a higher penetration of electrification changed the key modeling assumptions for the portfolio and produced a higher electric demand forecast, higher CETA renewable need and a higher peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity Q selected higher resource builds and had higher portfolio costs compared to the Mid Scenario. More capacity was added in nearly every resource category to meet the increased demand forecast.

ASSUMPTIONS. The demand forecast is adjusted to add a transition from natural gas to electricity for end uses in the PSE service territory resulting in a higher electric demand forecast. PSE hired Cadmus to develop the adjusted electric load which assumes an increase in energy of 203 aMW in 2030 to 641 aMW by 2045 from the Mid Scenario. Figure 8-107 shows the annual electric load (aMW) used for Sensitivity Q compared to the Mid and High Scenarios. In

comparison to the electric load in the High Scenario, the electric load for Sensitivity Q is lower through 2036, then higher by 154 aMW by 2045. More information on the load conversion assumptions can be found in Appendix E, Conservation Potential Assessment.

Figure 8-107: Electric Energy Demand Forecast for the Mid and High Scenario Compared to Sensitivity Q (Electrification) Demand Forecast (aMW)

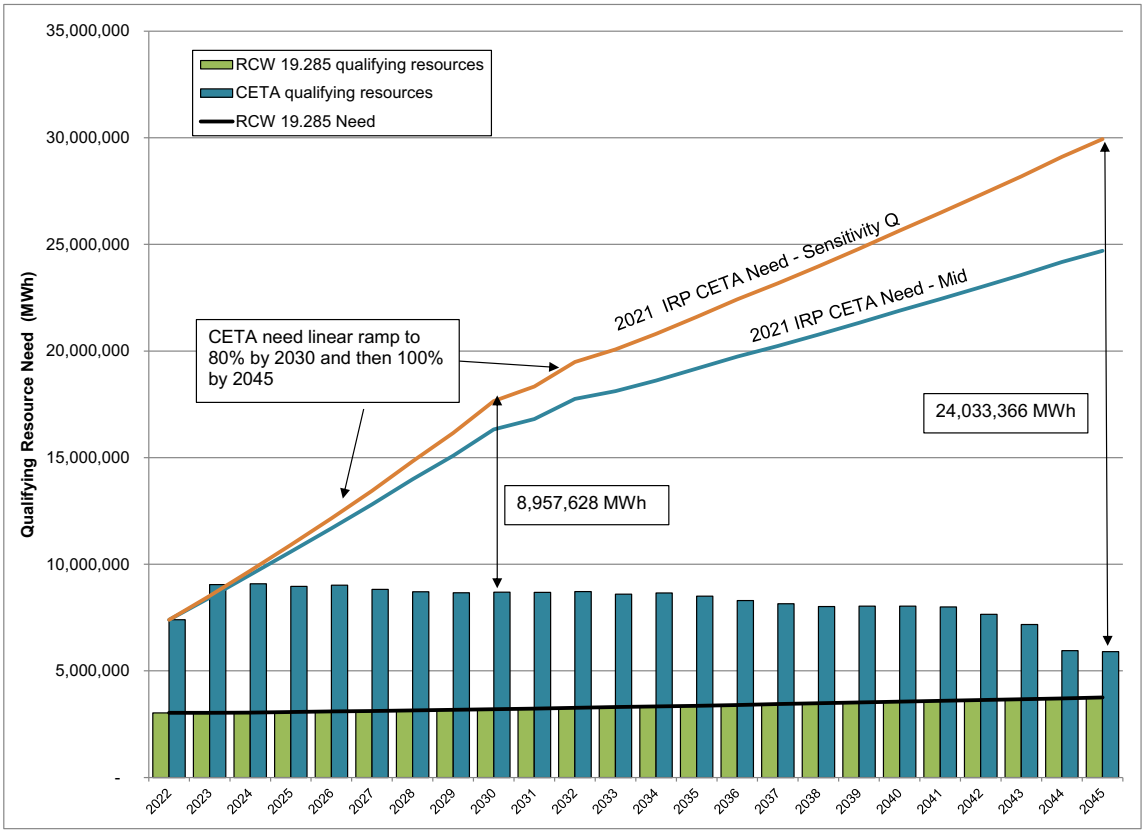


The increased electric demand requires additional CETA-compliant electricity above the Mid Scenario. To reflect this increased electric demand, the CETA renewable need is updated to reflect the change in the electric demand forecast. Figures 8-108 and 8-109 show the CETA renewable need for Sensitivity Q compared to the Mid Scenario. In Sensitivity Q, the CETA renewable need in 2045 is 24 million MWhs, an increase of 5.2 million MWhs from the Mid Scenario.

Figure 8-108: CETA Renewable Need – Mid Scenario and Sensitivity Q by 2030 and 2045

		CETA Renewable Need (MWh)	
	Portfolio	2030	2045
1	Mid Scenario	7,632,507	18,797,944
Q	Fuel Switching, Gas to Electric	8,957,628	24,033,366

Figure 8-109: CETA Renewable Need – Mid Scenario and Sensitivity Q

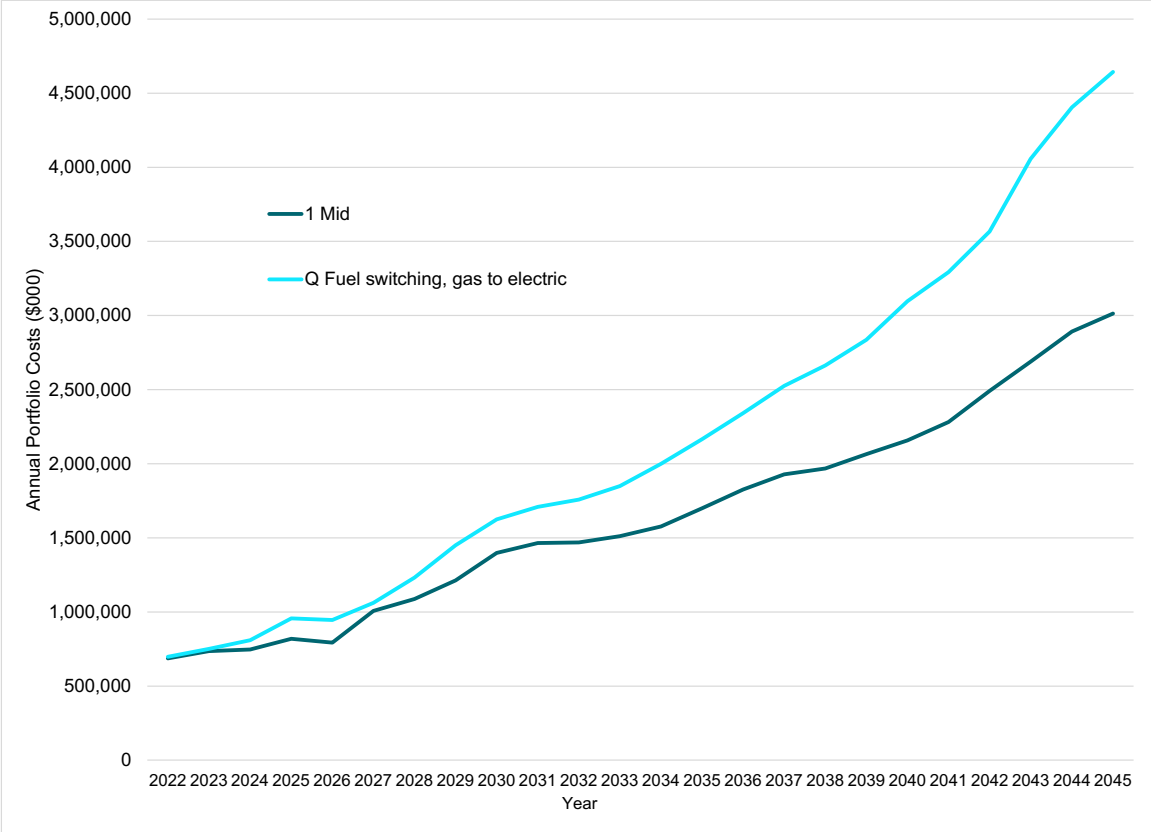


ANNUAL PORTFOLIO COSTS. Figures 8-110 and 8-111 illustrate the breakdown of portfolio costs between the Mid Scenario and Sensitivity Q. Due to the significant increase in electric demand and renewable need, costs for Sensitivity Q are much higher than the Mid Scenario. Additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs, are not included in this analysis.

Figure 8-110: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Q

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Q	Fuel Switching, Gas to Electric	$19.56	$5.60	$25.16	$4.54

Figure 8-111: Annual Portfolio Costs – Mid Scenario and Sensitivity Q



RESOURCE ADDITIONS. Figures 8-112 and 8-113 compare the nameplate capacity additions of Sensitivity Q and the Mid Scenario portfolios. Sensitivity Q added more capacity in nearly every resource category to meet the increased demand forecast, except for wind which shifted to an increase in Wind + Battery hybrid resource. Sensitivity Q selected conservation Bundle 11, whereas the Mid Scenario selected Bundle 10.

Figure 8-112: Portfolio Additions – Mid Scenario and Sensitivity Q

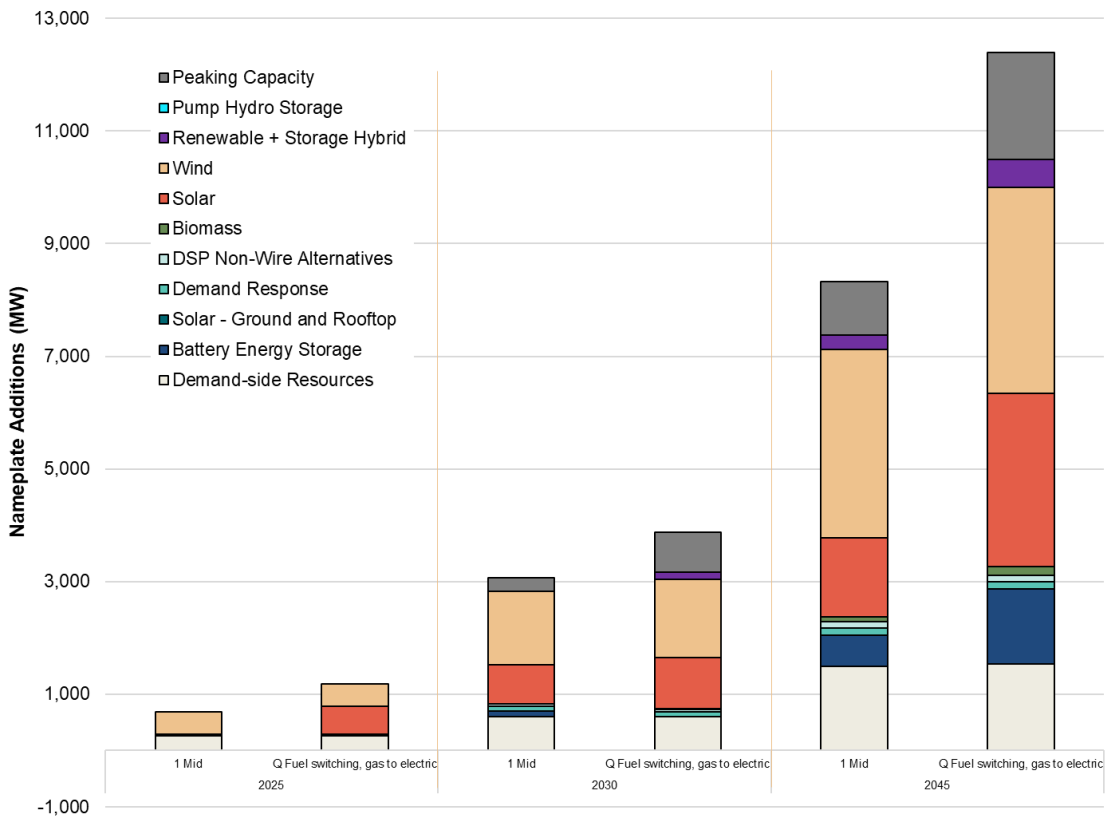
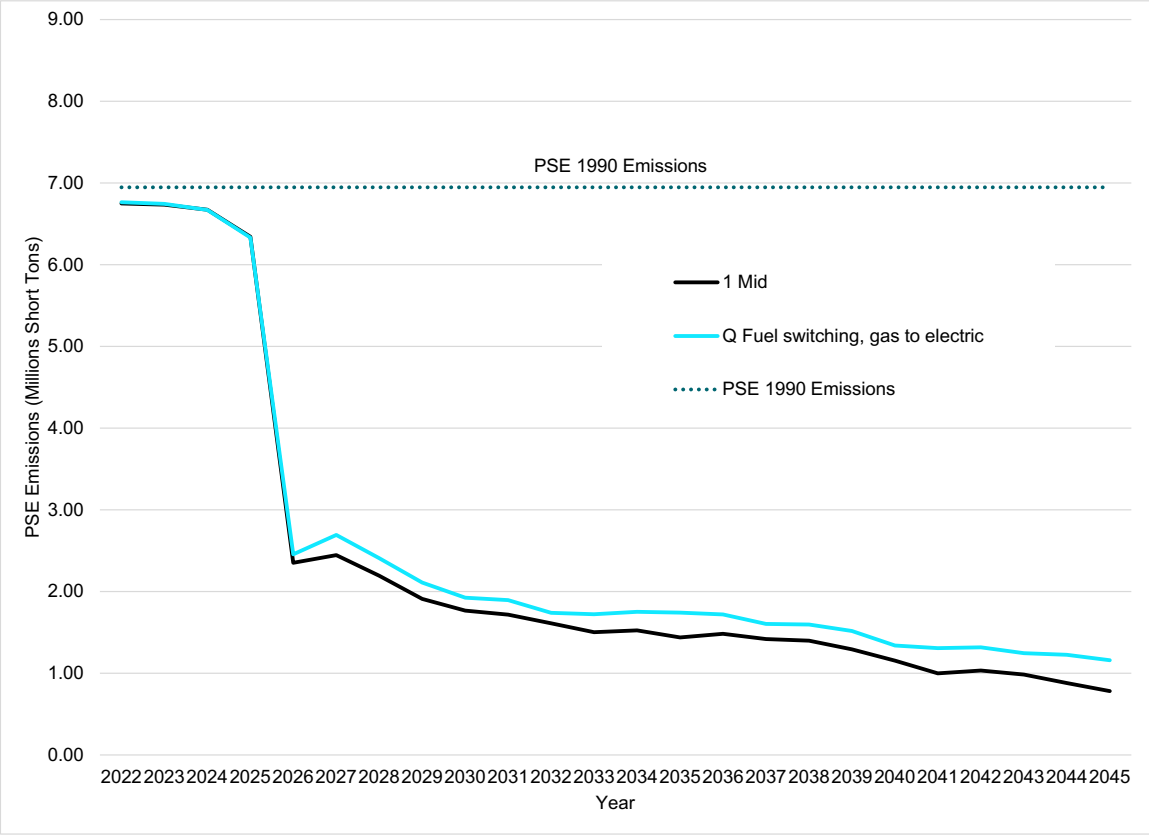


Figure 8-113: Portfolio Additions – Mid Scenario and Sensitivity Q

Resource Additions by 2045	1 Mid	Q Fuel Switching, Gas to Electric
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,325 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,888 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	3,088 MW
Wind	3,350 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW

EMISSIONS. The amount of peaking capacity resources doubled from 948 MW in the Mid Scenario to 1,896 MW in Sensitivity Q as result of the higher energy and peak need, despite increases in demand response and batteries. The higher dispatch from these flexible capacity resources produce a slightly higher overall emissions compared to the Mid Scenario. Figure 8-114 compares the emissions of the Mid Scenario and Sensitivity Q.

Figure 8-114: Direct GHG Emissions – Mid Scenario and Sensitivity Q



R. Temperature Sensitivity

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

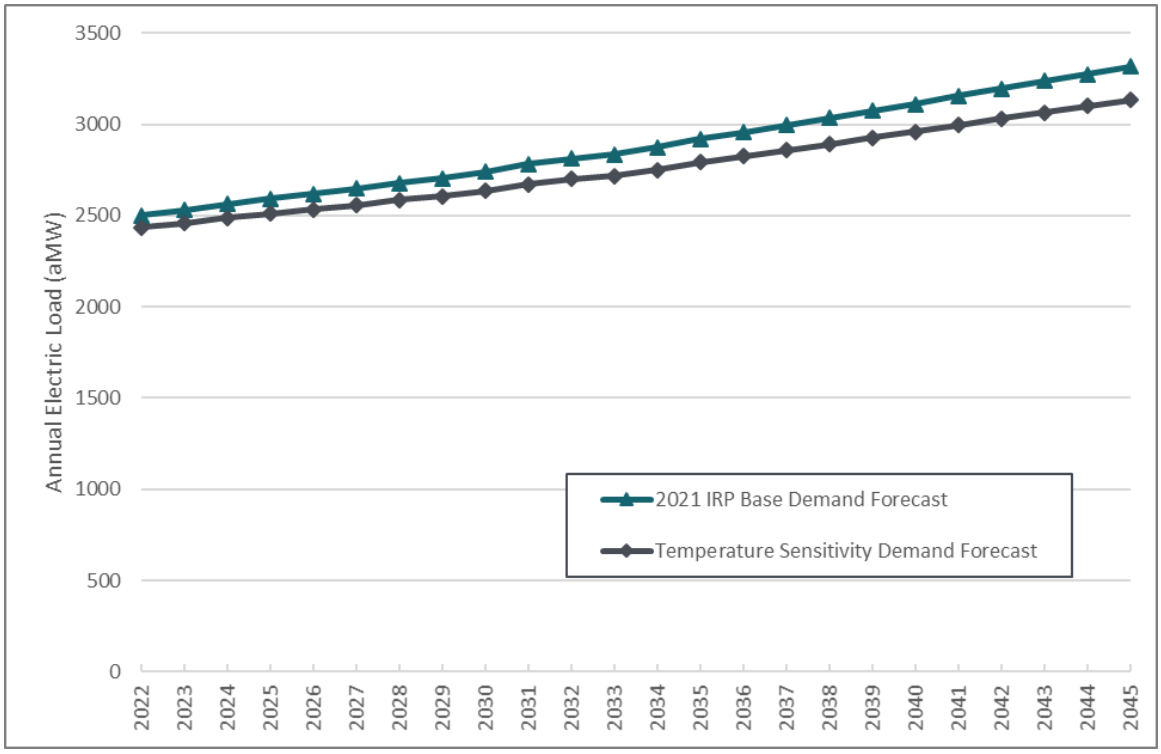
Baseline: The IRP Base Demand Forecast used in the Mid Scenario is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019.

Sensitivity R > PSE used forecast temperature data from the Northwest Power and Conservation Council (the "Council") to model a new demand forecast. The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, the rate of temperature increase found in the Council's climate model. PSE also updated the peak capacity need using the resource adequacy analysis. A full description of the temperature sensitivity can be found in Chapter 7.

KEY FINDINGS. Using alternative temperature data for forecasting demand and peak changed the key modeling assumptions for the portfolio and produced a lower demand forecast, lower CETA renewable need and a lower peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity R selected lower resource builds and had lower portfolio costs compared to the Mid Scenario. Resource additions were driven by the CETA renewable need, and a total of 4,495 MW nameplate capacity of renewable resources was added by 2045 to meet CETA.

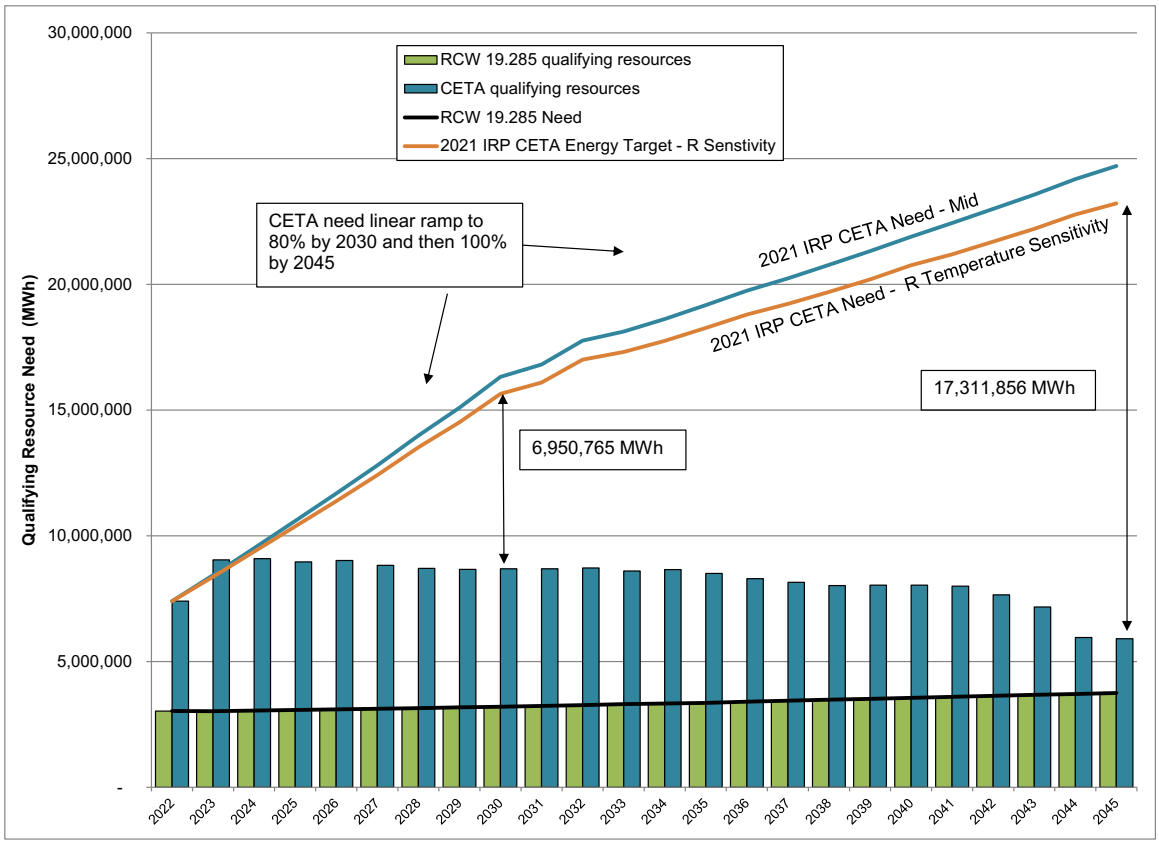
ASSUMPTIONS. In this sensitivity, the demand forecast reflects temperatures warming over time based on the trend of one model that the Council is using in its climate analyses. The related demand forecast is discussed in Chapter 6, Demand Forecasts. Figure 8-115 shows the annual electric load (aMW) used for Sensitivity R compared to the Mid Scenario.

Figure 8-115: Electric Energy Demand Forecast – Mid Scenario Compared to Temperature Sensitivity Demand Forecast (aMW)



The CETA renewable need is updated to reflect the change in the electric demand forecast. Figure 8-116 shows the CETA renewable need for Sensitivity R compared to the Mid Scenario. In Sensitivity R, the CETA renewable need in 2045 is 17.3 million MWhs, a decrease of 1.5 million MWhs from the Mid Scenario.

Figure 8-116: CETA Renewable Need – Mid Scenario and Sensitivity R



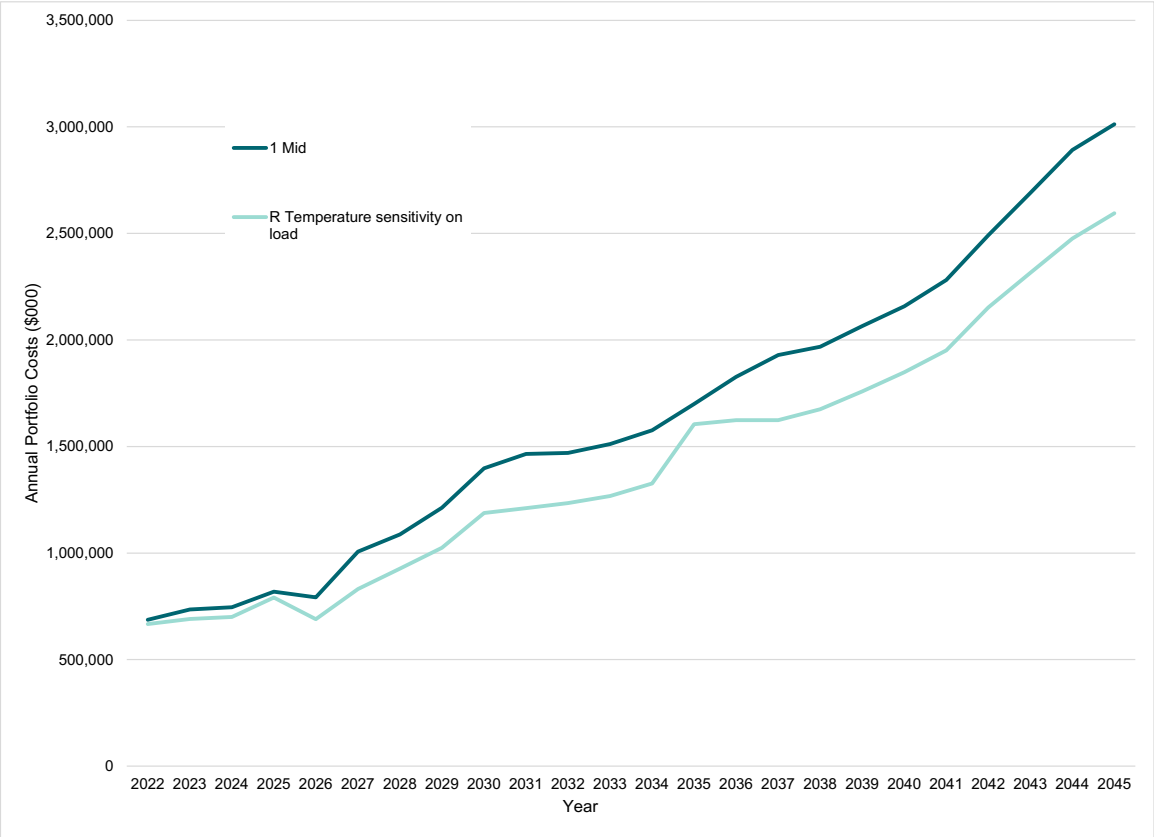
In addition to the change in the electric demand forecast and CETA renewable need, the Resource Adequacy Model was run for this temperature sensitivity reflecting a decrease in peak capacity need from 907 MW to 328 MW in 2027, and from 1,381 MW to 1,019 MW in 2031. More information on this sensitivity can be found in Chapter 7, Resource Adequacy Analysis.

ANNUAL PORTFOLIO COSTS. Figures 8-117 and 8-118 illustrate the breakdown of costs between the Mid Scenario and Sensitivity R. The reduction in costs for Sensitivity R is due to the decrease in the overall resource builds.

Figure 8-117: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity R

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
R	Temperature Sensitivity	$13.53	$4.69	$18.22	($2.40)

Figure 8-118: Annual Portfolio Costs – Mid Scenario and Sensitivity R



RESOURCE ADDITIONS. Figures 8-119 and 8-120 compare the nameplate capacity additions of the Sensitivity R and Mid Scenario portfolios. Peaking capacity resources are not added in Sensitivity R. All other resource options have lower additions except for 2-hour lithium-ion batteries and biomass, both of which showed a minor increase. Sensitivity R selected conservation Bundle 9, which includes 1,372 MW of capacity, whereas the Mid Scenario selected Bundle 10.

Figure 8-119: Portfolio Additions – Mid Scenario and Sensitivity R

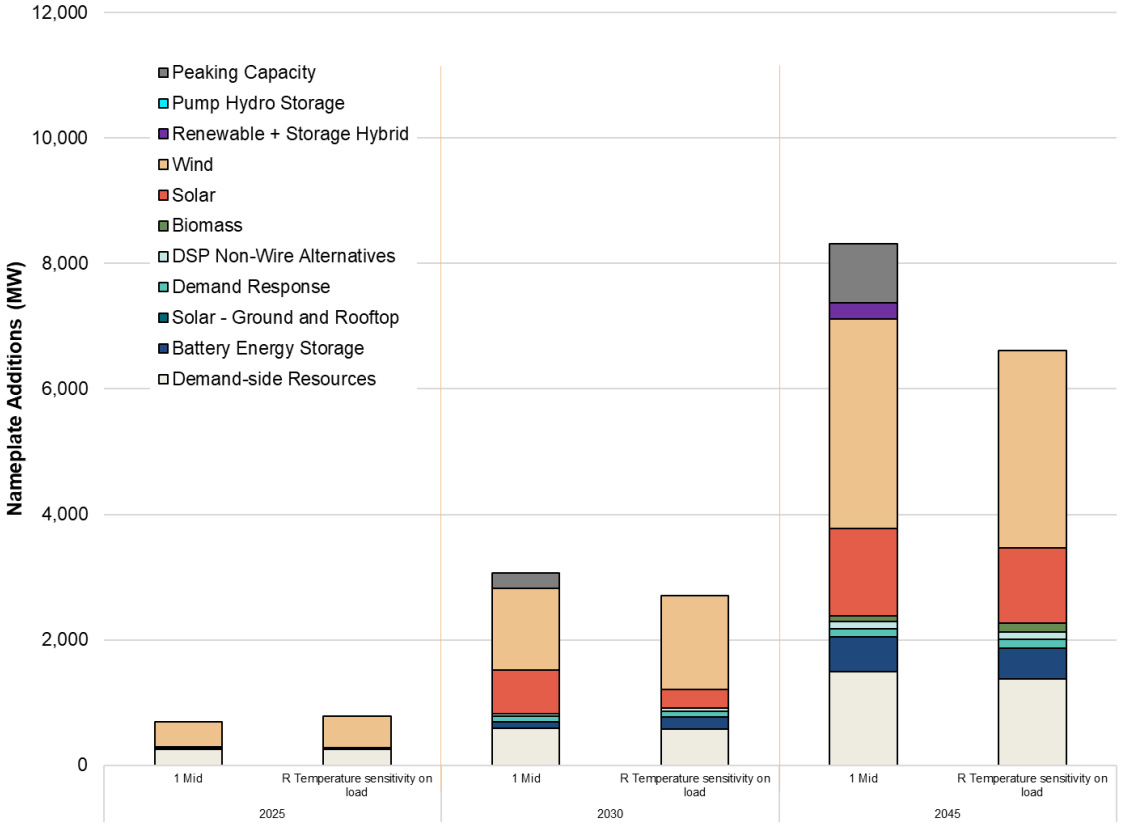
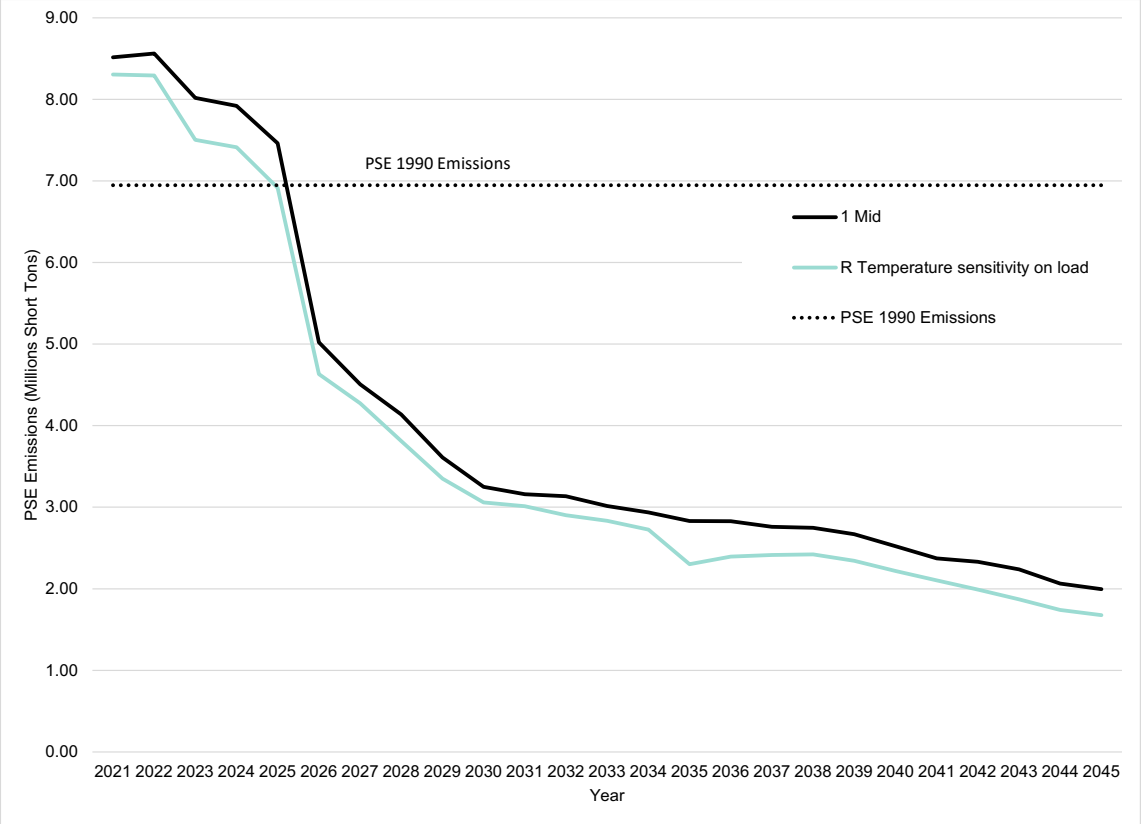


Figure 8-120: Portfolio Additions – Mid Scenario and Sensitivity R

Resource Additions by 2045	1 Mid	R Temperature sensitivity on load
Demand-side Resources	1,497 MW	1,372 MW
Battery Energy Storage	550 MW	500 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	130 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,495 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,195 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	0 MW

EMISSIONS AND ECONOMIC RETIREMENTS. Sensitivity R resulted in fewer GHG emissions compared to the Mid Scenario. This is due to the lower dispatch of existing thermal resources and the lack of peaking capacity resource additions. The lower energy demand and peak capacity need also contributed to the economic retirement of existing thermal plants. Two of the natural gas resources were retired by 2023 and replaced by 2-hour lithium-ion batteries. Figure 8-121 compares the GHG emissions from Sensitivity R with the Mid Scenario.

Figure 8-121: Annual Emissions – Mid Scenario and Portfolio R



CETA Costs

S. SCGHG Cost Included, No CETA
T. No CETA

The purpose of this sensitivity is to evaluate the cost of CETA compliance. To assess the effect of CETA and the SCGHG, a baseline must be established. Sensitivity S models PSE without the CETA renewable generation requirement. Sensitivity T models PSE without the CETA renewable requirement or the SCGHG. By analyzing the PSE portfolios without CETA requirements, the impact of CETA can be quantified.

Baseline: The Mid Scenario includes SCGHG for thermal resources as a fixed cost adder and CETA requirements.
Sensitivity S > The model includes SCGHG as a fixed cost adder, but there is no CETA renewable requirement.
Sensitivity T > The model includes no SCGHG and no CETA renewable requirement.

KEY FINDINGS. Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.05 billion dollars, $6.48 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is higher by $0.02 billion dollars. The price differences between Sensitivity S and T are negligible, indicating that some conservation and demand response additions can be a revenue requirement-neutral way of cutting emissions. Even so, less conservation is selected in both sensitivities compared to the Mid Scenario.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.

In Sensitivity S, the SCGHG is included as a fixed cost adder for thermal resources during resource selection. The CETA renewable generation requirement is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

In Sensitivity T, there is no CETA renewable requirement and the SCGHG is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

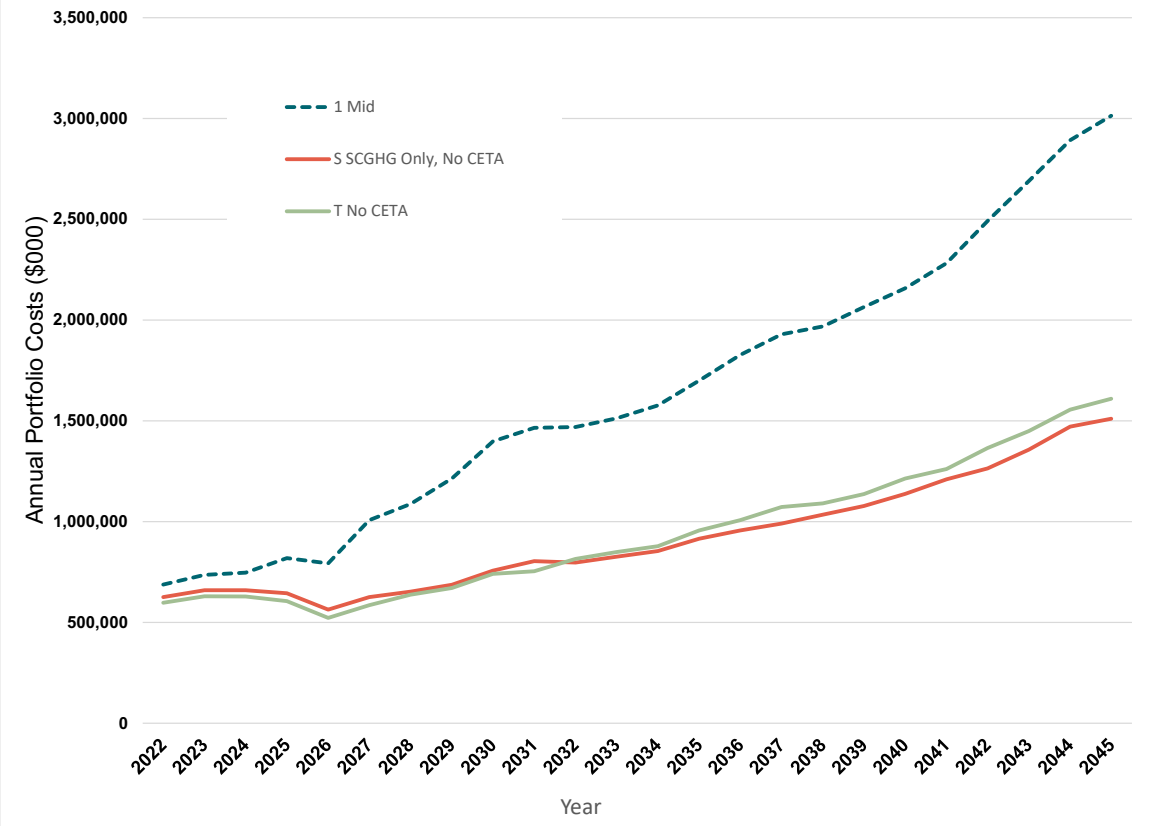
ANNUAL PORTFOLIO COSTS. Figures 8-122 and 8-123 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The conservation resources selected in Sensitivity S drive the revenue requirements of the portfolio even lower compared to

Sensitivity T, as they slow the pace of peaker construction and prevent an additional frame peaker from being built by 2045. Since the SCGHG is not included in Sensitivity T, the costs of emissions are not included.

Figure 8-122: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
S	SCGHG Only, No CETA	$9.03	$8.86	$17.89	($2.73)
T	No CETA, No SCGHG	$9.05	--	$9.05	($11.57)

Figure 8-123: Annual Portfolio Costs – Mid Scenario, Sensitivities S and Sensitivity T



RESOURCE ADDITIONS. Figure 8-124 compares the nameplate capacity additions of the Mid Scenario to Sensitivities S and T. The build patterns of Sensitivities S and T are similar and simple; both portfolios build frame peakers to keep up with increasing demand. Aside from the Montana wind addition in 2044 to maintain compliance with the RPS requirement, no new renewable resources are built in either portfolio. In Sensitivity T, conservation Bundle 2 is selected, along with 3 demand response measures. In Sensitivity S, conservation Bundle 6 is selected, along with 11 demand response measures. Sensitivity S also builds 50 MW of 2-hour lithium-ion batteries in 2025. The additional demand response, conservation, and storage added in Sensitivity S results in one less frame peaker resource being built by 2045 compared to Sensitivity T.

Figure 8-124: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T

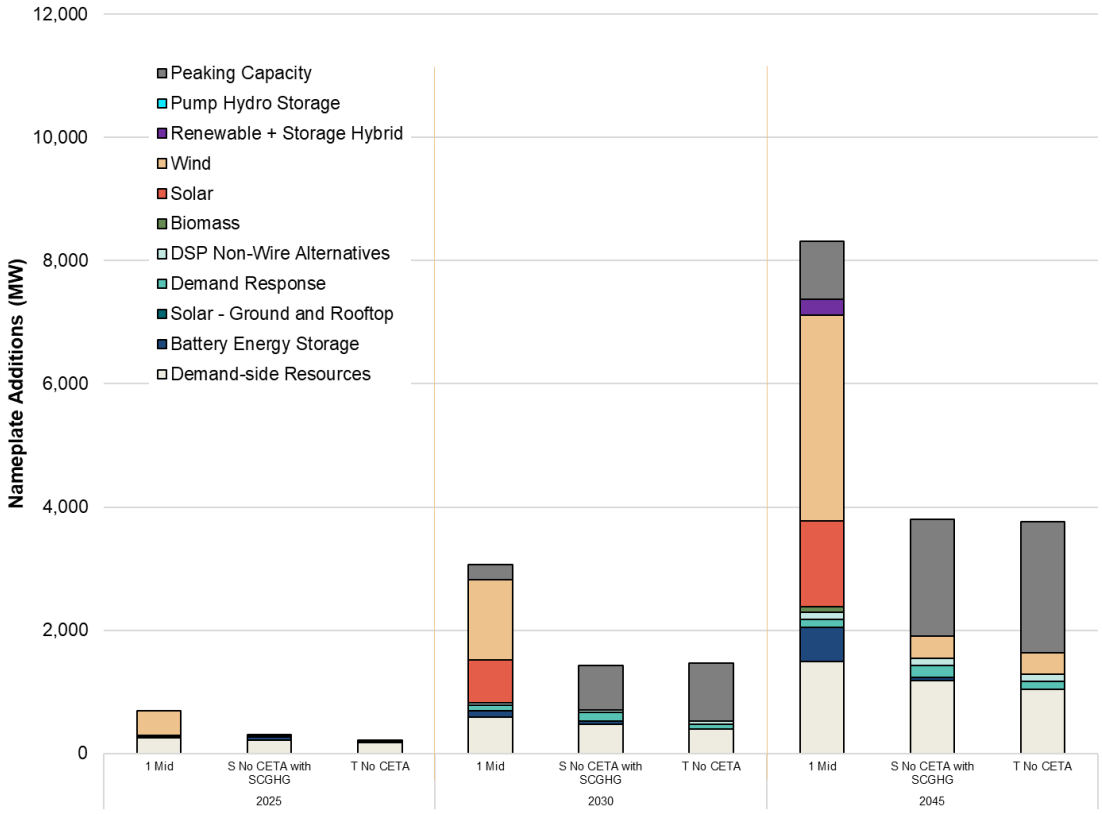


Figure 8-125: Portfolio Additions by 2045 – Mid Scenario, Sensitivity S and Sensitivity T

Resource Additions by 2045	1 Mid	S SCGHG Only, No CETA	T No CETA
Demand-side Resources	1,497 MW	1,179 MW	1,042 MW
Battery Energy Storage	550 MW	50 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	203 MW	123 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	350 MW	350 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	0 MW	0 MW
Wind	3,350 MW	350 MW	350 MW
Renewable + Storage Hybrid	250 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW	2,133 MW

EMISSIONS. As expected, the S and T portfolios have a significantly higher rate of emissions than the Mid Scenario. The ultimate goal of CETA is to reduce GHG emissions, and the S and T portfolios demonstrate the need for CETA in curbing emissions from PSE's portfolio. Figure 8-126 shows the annual emissions of the PSE portfolio in Sensitivities S and T.

Figure 8-126: Portfolio Emissions – Mid Scenario, Sensitivity S and Sensitivity T (market purchases are not included)



U. 2% Cost Cap Threshold

The incremental cost of compliance section of CETA states:

> An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a two percent increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year, as reported by the investor-owned utility in its most recent commission basis report.[6]

6 / RCW 19.405.060 3(a)

PSE calculated the incremental cost as the difference between Portfolio T, No CETA with SCGHG adder, and the preferred portfolio, Portfolio W. The calculation is as follows:

$$Incremental\ Cost = Preferred\ Portfolio\ Annual\ Cost - No\ CETA\ with\ SCGHG\ adder\ annual\ Cost$$

The 2 percent cost threshold is calculated based upon the expected annual revenue requirement. Figure 8-127 illustrates how the 2 percent cost threshold is calculated. First, the current revenue requirement is established using PSE's 2019 General Rate Case (GRC) revenue requirement. The GRC revenue requirement is adjusted for inflation at 2.5 percent per year to obtain the estimated 2021 revenue requirement (shown in the top half of the figure). The 2 percent cost threshold for the year 2022 is simply 2 percent of the inflation-adjusted GRC revenue requirement in 2021, approximately $44 million. For subsequent years, 2 percent of the inflation-adjusted GRC revenue requirement is added to the previous 2 percent cost threshold (also adjusted for inflation). This creates the compounding 2 percent cost threshold (shown in the bottom half of the figure).

Figure 8-127: Calculation of the 2 Percent Cost Threshold

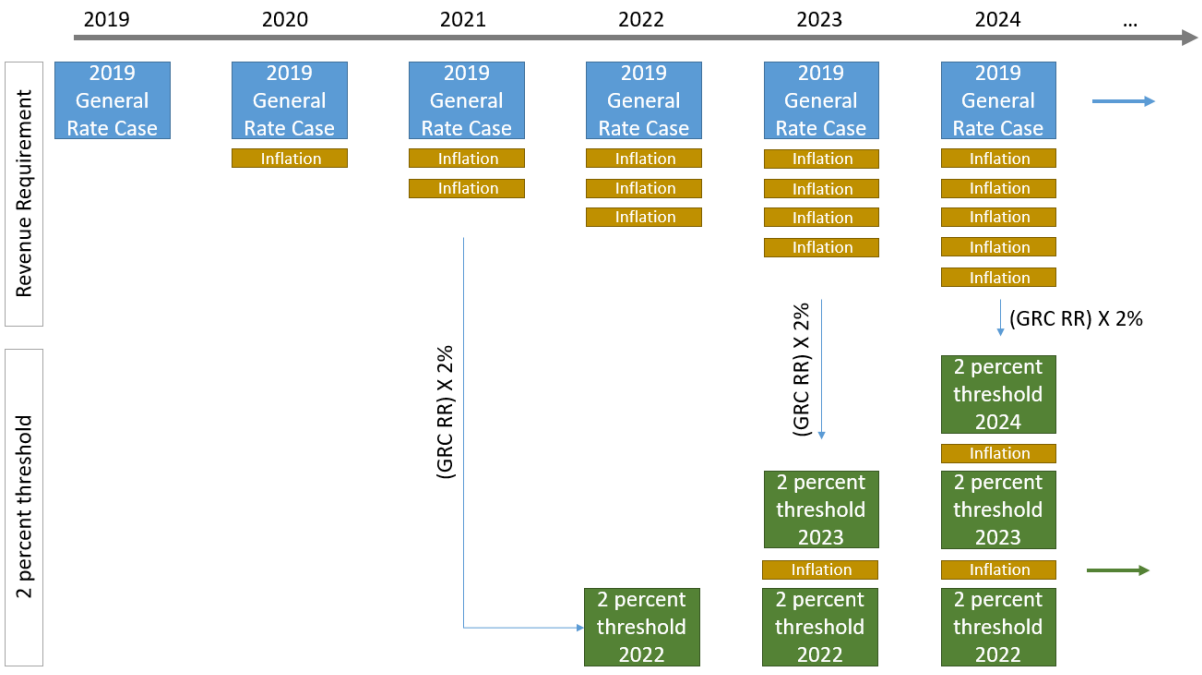
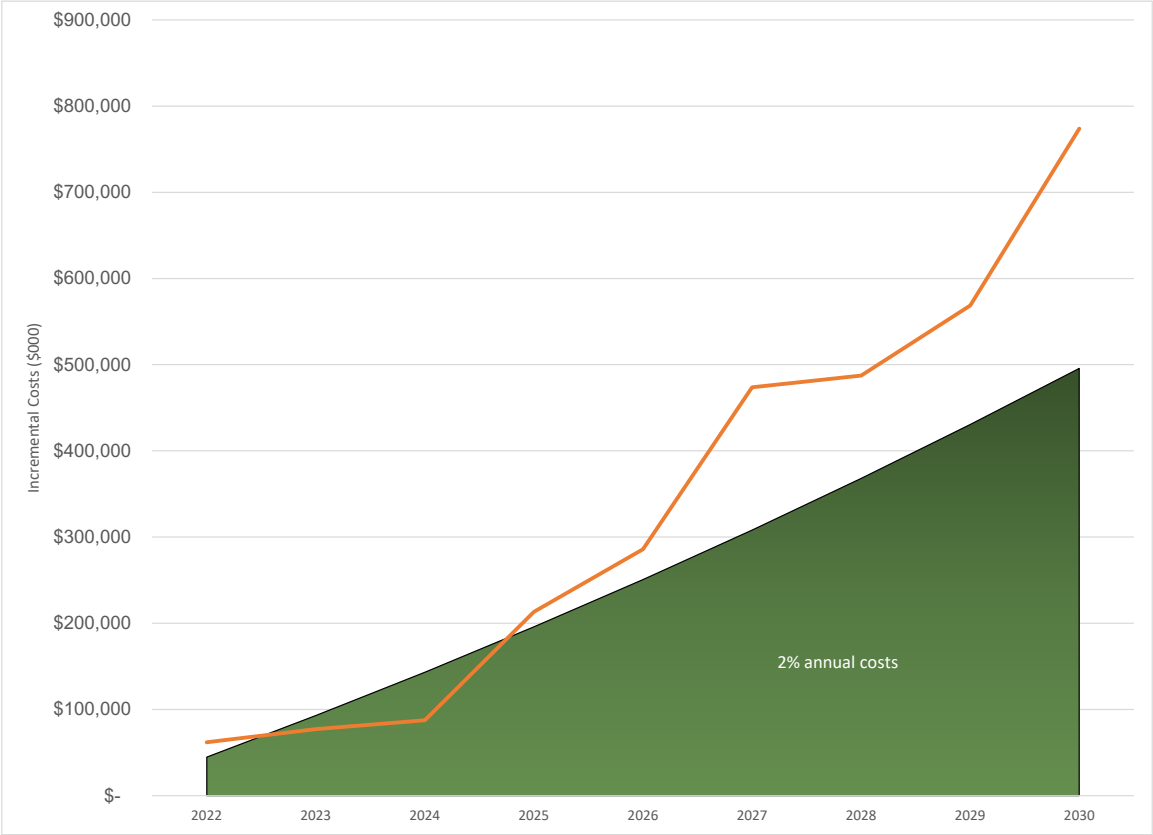


Figure 8-128 compares the 2 percent cost threshold (the green area) with the incremental cost of the preferred portfolio (the orange line). By 2025, the cost of CETA compliance increases to more than the 2 percent cost threshold.

Figure 8-128: Incremental Cost of CETA Compliance



There is some uncertainty associated with this comparison. The annual portfolio costs only include the costs associated with generating resources modeled in the IRP. There may be other costs that are not captured as part of the IRP analysis. Better clarity into this comparison will be obtained through the CEIP. All costs associated with the CETA implementation will be available and included in CEIP. In this IRP, PSE has included the cost of compliance calculation and a comparison with the preferred portfolio for information only.

Balanced Portfolios

V. Balanced Portfolio

Sensitivity V applies insights gained from the analysis of other sensitivities to compare with the results to the Mid Scenario portfolio. Sensitivity V gives increased consideration to distributed energy resources, ramping those and other customer programs in over time starting in 2025. In contrast, the Mid Scenario capacity expansion model is set to optimize total portfolio cost and builds new resources toward the end of the planning period because the cost curve of all resources declines over time. In Sensitivity C, for example, the model waits until the end of the planning period to add a significant amount of distributed resources. However, waiting until the end is not always realistic.

Baseline: New resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity V1 > Increased distributed energy resources and customer programs are ramped in over time. These include rooftop and ground-mounted solar, demand response programs, battery energy storage, customer-owned rooftop solar and an expanded Green Direct program.
Sensitivity V2 > Same as Sensitivity V1, with the substitution of a Montana wind + pumped hydro storage resource for the first eastern Montana resource constructed in 2028, similar to Sensitivity AA described below.
Sensitivity V3 > Same as Sensitivity V1, except conservation measures ramp in over 6 years instead of 10 years, similar to Sensitivity F described above.

KEY FINDINGS. Ramping in resource additions versus economic resource selection resulted in higher portfolio costs in Sensitivity V variations compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources after the addition of Montana and Wyoming wind resources in the Mid Scenario portfolio. In Sensitivity V1, the 24-year levelized revenue requirement is $16.06 billion, an increase of $0.47 billion or 3 percent over the Mid Scenario portfolio. Adding MT wind plus pumped hydro storage (V2) or a 6-year DSR ramp increases these costs further.



ASSUMPTIONS. Sensitivity V1 assumes greater investment in distributed energy resources and load-reducing resources like the Green Direct program and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as must-take resource additions. These must-take resource additions include:

- Addition of 50 MW of distributed, ground-mounted solar in the year 2025.
- Annual addition of 30 MW of distributed, rooftop solar from the year 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Addition of all demand response programs with a cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from the year 2025 to 2031 for a total of 175 MW of nameplate capacity.
- An adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.
- Addition of three new Green Direct programs consisting of 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. All generic resource options are still available for economic selection by the optimization model.

Sensitivity V2 makes the same assumptions as Sensitivity V1 except a Montana wind + pumped hydro storage resource is forced into the portfolio in the year 2028.

Sensitivity V3 makes the same assumptions as Sensitivity V1 except conservation measures are implemented over 6 years instead of 10 years and associated costs and energy savings are updated.

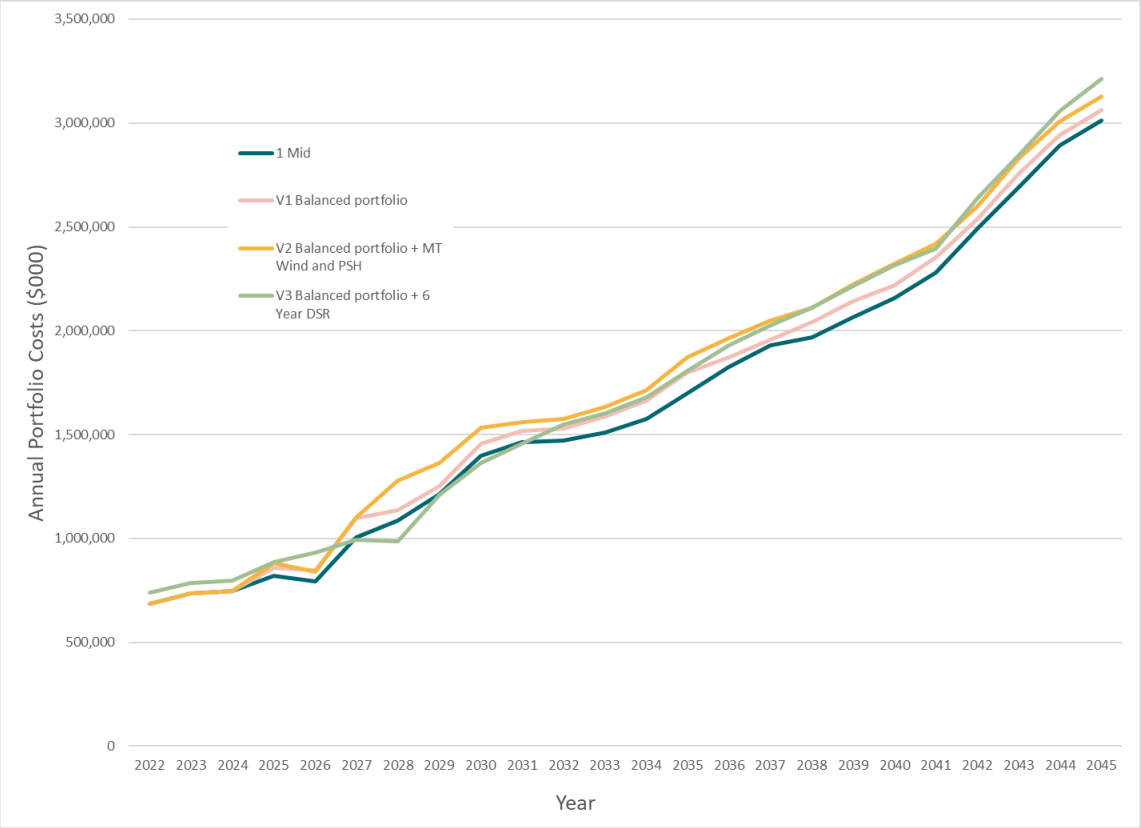
PORTFOLIO COSTS. Figures 8-129 and 8-130 compare the portfolio costs and annual revenue requirements, respectively, of the Sensitivity V variations and the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in overall higher portfolio costs for the Sensitivity V variations compared to the Mid Scenario. Sensitivity V1 has a slightly higher revenue requirement from 2024 to the end of the planning period compared to the Mid Scenario. Sensitivity V2 has a significant increase the annual revenue requirement in 2028 from the addition of the expensive Montana wind plus pumped hydro storage resource and never recovers those costs compared to the Mid Scenario. Sensitivity V3 starts as the most expensive portfolio due to the accelerated ramp of conservation measures, and then sees some cost savings in the years 2027 to 2032 compared to the Mid Scenario. However, in 2032 the Mid Scenario conservation measures complete their 10-year ramp-in, equalizing the energy savings between the two portfolios. After 2032, Sensitivity V3 costs increase above the Mid Scenario due to resource acquisitions in the later portion of the planning period.

The SCGHG for the Sensitivity V variations is similar the SCGHG for the Mid Scenario. Sensitivities V1 and V2 achieve slightly lower SCGHG than the Mid Scenario, while Sensitivity V2 has a slightly higher SCGHG overall.

Figure 8-129: Portfolio Cost Comparison – Mid Scenario and Sensitivities V, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
V1	Balanced Portfolio	$16.06	$5.07	$21.14	$0.54
V2	Balanced Portfolio with MT wind + PHES	$16.61	$5.12	$21.73	$1.11
V3	Balanced Portfolio with 6-year DSR	$16.26	$5.06	$21.32	$0.70

Figure 8-130: Annual Portfolio Costs – Mid Scenario and Sensitivities V1, V2 and V3



RESOURCE ADDITIONS. Figures 8-131 and 8-132 compare the nameplate capacity additions of the Sensitivity V variations and the Mid Scenario portfolio. Resource additions for Sensitivity V1 and the Mid Scenario are similar, except for the quantity of ground-mounted and rooftop solar forced into the portfolio in the early years that displaces utility-scale solar. Resource additions for the Sensitivity V variations are all very similar. Sensitivity V3 delays acquisition of resources until the later years of the planning period, but concludes the planning period with a similar resource mix as Sensitivities V1 and V2.

Figure 8-131: Portfolio Additions – Mid Scenario and Sensitivities V1, V2 and V3

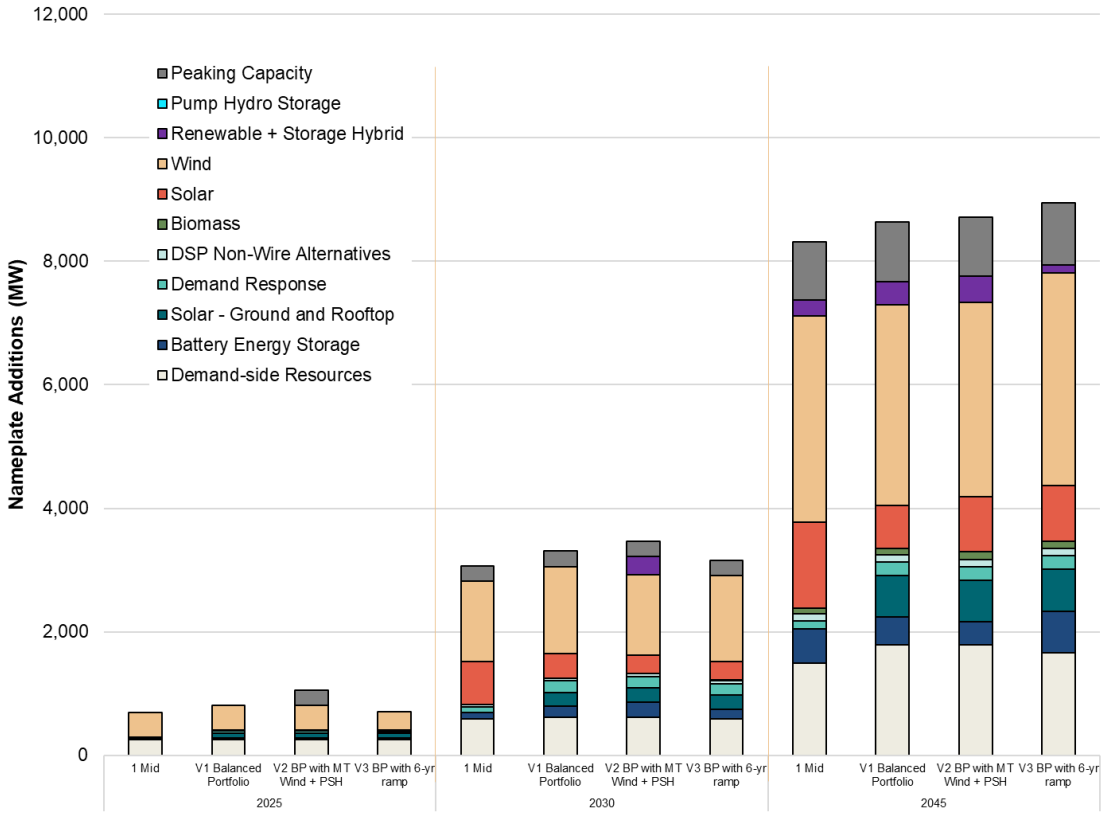
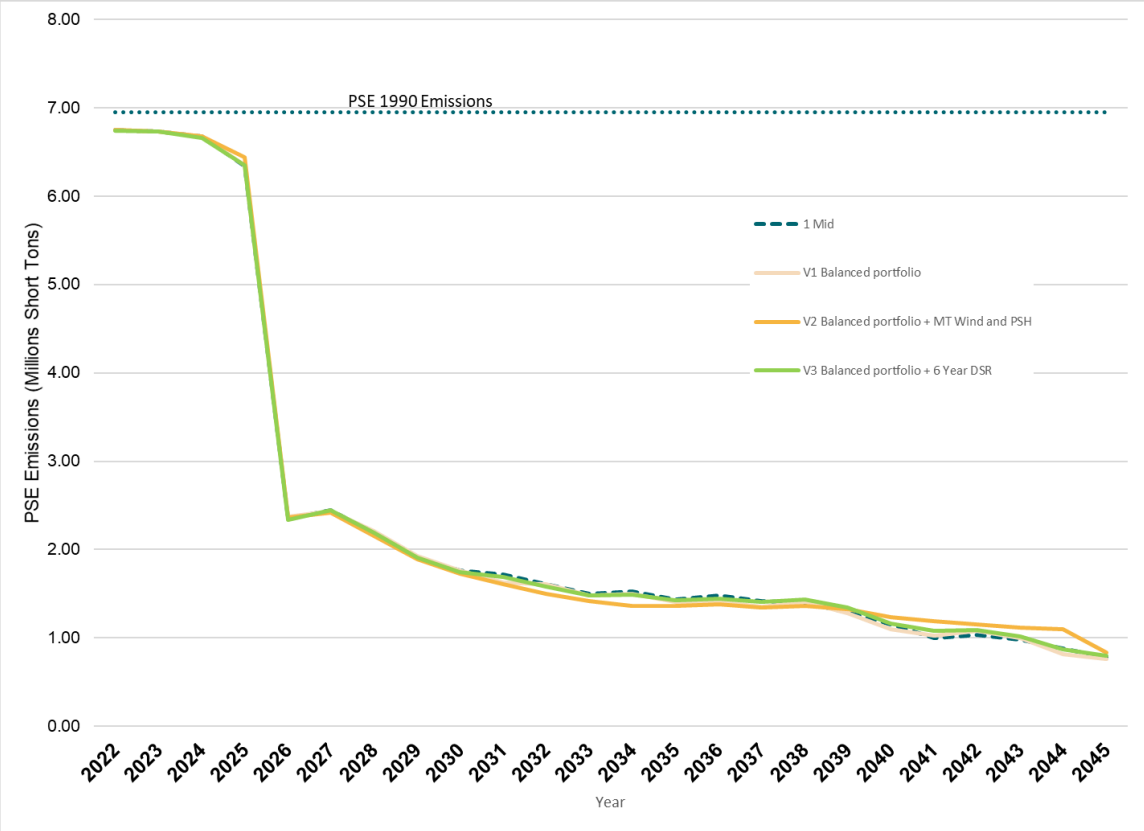


Figure 8-132: Portfolio Additions by 2045 – Sensitivities V1, V2 and V3

Resource Additions by 2045	Mid Scenario Portfolio	Sensitivity V1 - Balanced Portfolio	Balanced Portfolio with MT wind + PHES	Balanced Portfolio with 6-year DSR
Demand-side Resources	1,497 MW	1,784 MW	1,784 MW	1,658 MW
Battery Energy Storage	550 MW	450 MW	375 MW	675 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,051 MW	4,165 MW	4,465 MW
Biomass	90 MW	105 MW	120 MW	120 MW
Solar	1,393 MW	696 MW	895 MW	895 MW
Wind	3,350 MW	3,250 MW	3,150 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	375 MW	425 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	948 MW	1,003 MW

OTHER FINDINGS: GHG Emissions. Figure 8-133 compares the direct GHG emissions from Sensitivities V1, V2 and V3 with the Mid Scenario. Significant emissions reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. All three Sensitivity V variations show similar reductions in emissions by the year 2045.

Figure 8-133: Portfolio GHG Emissions – Sensitivities V1, V2 and V3

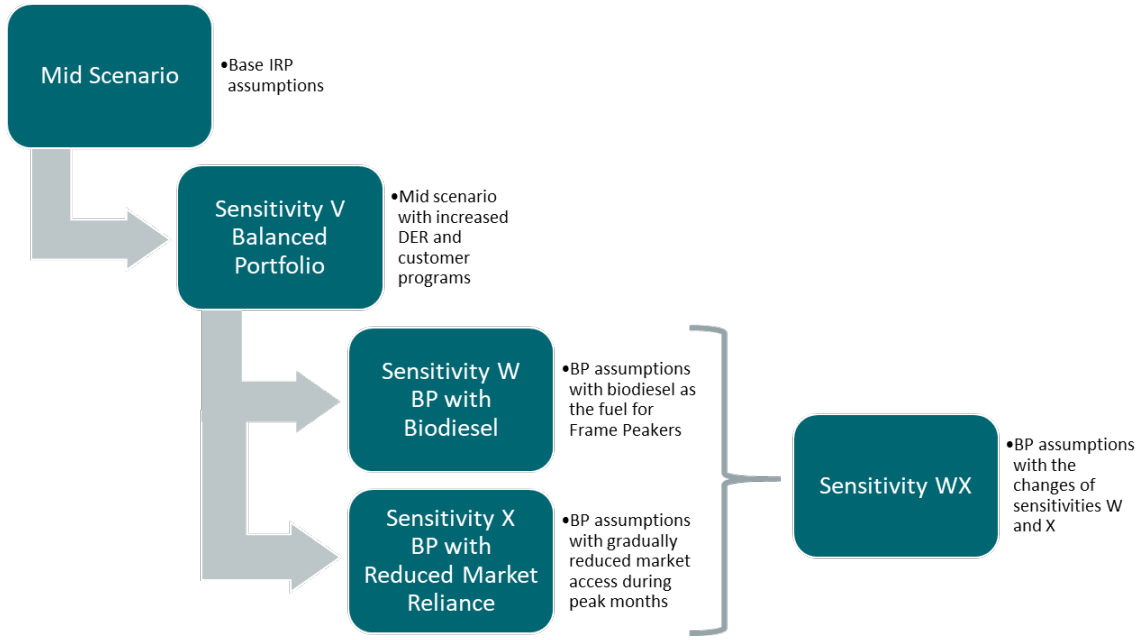


W. Balanced Portfolio with Alternative Fuel
X. Balanced Portfolio with Reduced Market Reliance
WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivities W and X incorporate significant changes to Sensitivity V1, the Balanced Portfolio. Sensitivity W substitutes biodiesel for natural gas in new peaking capacity resources and Sensitivity X reduces the market reliance of the portfolio. Sensitivity WX applies the key changes in Sensitivities W and X simultaneously. Figure 8-134 illustrates how these changes are applied.

Figure 8-134: Sensitivities V, W, X and WX, and Their Relation to the Mid Scenario

BP = Balanced Portfolio



Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity W > Same as Sensitivity V1, with the addition of biodiesel as the fuel source for new frame peaker resources, similar to Sensitivity M.
Sensitivity X > Same as Sensitivity V1, but market purchases during seasonal peak conditions gradually decline by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August), similar to sensitivity B.
Sensitivity WX > Additional DER and customer programs are added to the portfolio. Biodiesel is used as a fuel for newly built frame peaker resources. The portfolio has reduced access to market purchases during peak demand months.

KEY FINDINGS: SENSITIVITY W. Extending the assumptions from Sensitivity V1 to include biodiesel as a fuel source for new frame peakers resulted in an increase of $0.57 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $16.10 billion, an increase of less than $0.04 billion from Sensitivity V1. Even with the premium on biodiesel fuel prices compared to natural gas prices, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario portfolio.

KEY FINDINGS: SENSITIVITY X. While ramping in distributed energy resources and customer programs over time helps to achieve increased renewable resources, introducing the reduced market reliance strategy creates tension, since Sensitivity X adds more peaking capacity resources compared to the Mid Scenario and Sensitivity V. The 24-year levelized revenue requirement for Sensitivity X is $17.21 billion, $1.68 billion more than the Mid Scenario and $1.14 billion more than Sensitivity V1.

KEY FINDINGS: SENSTIVITY WX. Portfolio WX is nearly identical to portfolio X. The same resources are selected at the same time. The only difference in builds is an increase in demand-side resources. Portfolio WX emissions decrease compared to portfolio X due to the use of biodiesel, but are higher than portfolio W due to the reduced availability of market purchases during peak hours.

ASSUMPTIONS: Sensitivity V1: Balanced Portfolio
Increased distributed energy resources and customer programs ramp in over time as follows:

- Addition of 50 MW of distributed, ground-mounted solar in 2025.
- Annual addition of 30 MW of distributed, rooftop solar from 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Annual addition of all demand response programs that cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from 2025 to 2031 for a total of 175 MW of nameplate capacity.
- Adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. (The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.)
- Addition of three new Green Direct programs: 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

ASSUMPTIONS: Sensitivity W. Sensitivity W uses the Sensitivity V1 assumptions, but also includes the use of alternative fuel for some peaking capacity resources. New frame peakers are assumed to be fueled by biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers continue to be fueled with natural gas throughout the modeling horizon. PSE estimated a biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020$, adjusted for inflation annually) informed by the U.S. Department of Energy's October 2020 Clean Cities Alternative Fuel Price Report.

ASSUMPTIONS: Sensitivity X. For Sensitivity X, available market purchases were constrained to capture the impact of reduced market reliance on the Balanced Portfolio. Available market

purchases during peak conditions are reduced by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August).

Figure 8-135 shows the Sensitivity X market purchase limits for each year and month.

Figure 8-135: Monthly Market Purchase Access in Portfolio X (MW)

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

ASSUMPTIONS: Sensitivity WX. Sensitivity WX combines the changes incorporated to Sensitivity W and Sensitivity X. Therefore, biodiesel is available for new frame peakers and the portfolio has reduced market purchase limits.

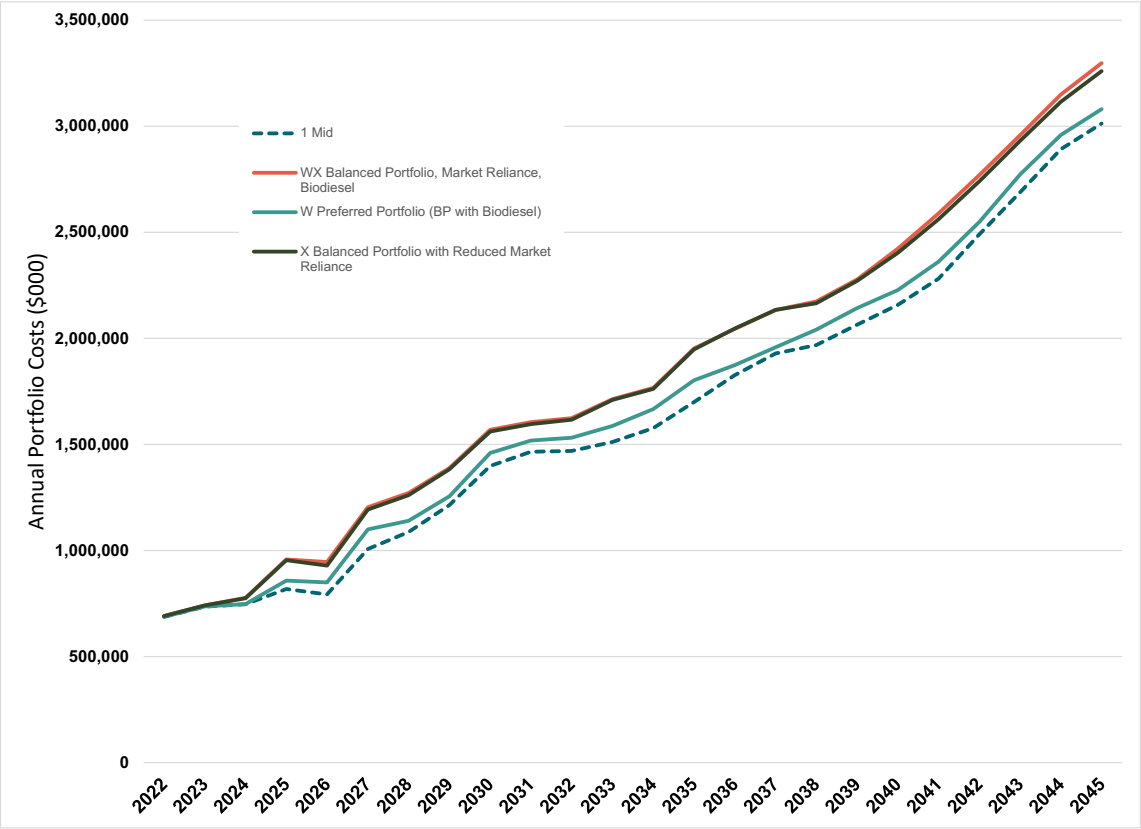
ANNUAL PORTFOLIO COSTS. Figures 8-136 and 8-137 show the portfolio costs and annual revenue requirements, respectively, of Sensitivities WX, W and X, compared to the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities WX, W and X. For Sensitivity W, increased portfolio costs are driven by the increased revenue requirements of the portfolio, as shown in Figure 8-X. Sensitivity W has slightly lower SCGHG due the use of alternative fuel for new peaking resources than the Mid Scenario portfolio. In Sensitivity X, the increased portfolio costs are due to the addition of more flexible capacity resources, which also increases the SCGHG. Portfolio WX significantly

increases the revenue requirement over the Mid Scenario portfolio, although less than the combined increases of the W and X portfolios over the Mid Scenario. The portfolio builds are nearly identical to portfolio X, but the use of biodiesel reduces the SCGHG costs and costs overall. The slight increase in portfolio costs compared to portfolio X is due to the use of biodiesel and increased investment in demand-side resources.

Figure 8-136: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities WX, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
WX	Balanced Portfolio, Biodiesel, Reduced Market Reliance	$17.30	$5.06	$22.36	$1.74
W	Balanced Portfolio, Biodiesel	$16.10	$4.96	$21.06	$0.44
X	Balanced Portfolio, Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95

Figure 8-137: Annual Portfolio Costs – Mid Scenario and Sensitivities WX, W and X



RESOURCE ADDITIONS. Figures 8-138 and 8-139 compare the nameplate capacity additions of Sensitivities W, X, WX and the Mid Scenario portfolios.

Portfolio builds for Sensitivity W are relatively similar to the wind and peaking capacity resource builds in the Mid Scenario. Wind is a low cost, CETA-eligible resource, so it is to be expected that all four portfolios selected similar amounts of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore, it is also to be expected that most portfolios will include some peaking capacity. Sensitivity W has an additional 18 MW of reciprocating peaker resources compared to the quantity of peaking capacity resources in the Mid Scenario. In Sensitivity W, new frame peaker resources are fueled with renewable biodiesel instead of natural gas which therefore does not include an SCGHG cost. However, biodiesel is also much more expensive than natural gas. At the current cost projections for biodiesel, it appears that the higher fuel price and lower SCGHG cost are offsetting each other, resulting in similar peaking resource decisions.

The primary differences between the Mid Scenario and Sensitivity W are related to the forced build decisions described in the assumptions section above. Increased distributed solar builds result in less utility-scale solar builds, as these resources fill a similar niche within the portfolio. Increased demand response programs in Sensitivity W may also offset some utility-scale solar builds.

More storage is built in Sensitivity W compared to the Mid Scenario portfolio. Sensitivity W ramps in 2-hour lithium-ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased distributed solar builds in both sensitivities. However, the storage in the Mid Scenario portfolio is comprised of 4-hour lithium-ion and 6-hour flow battery storage, which is built after year 2040. Sensitivity W shows similar late year additions of longer duration storage, despite the abundance of 2-hour storage added early in the modeling horizon. This shows that longer-duration storage is an important component of these portfolios.

With the reduced market purchase limit in Sensitivity X, more conservation resources, battery energy storage and peaking capacity resources are added to fill the energy that would have been purchased in the market.

The builds of portfolio WX are nearly identical to portfolio X, the only difference is an increase in demand-side resources. The construction timeline of resources is also the same in WX and X.

Figure 8-138: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

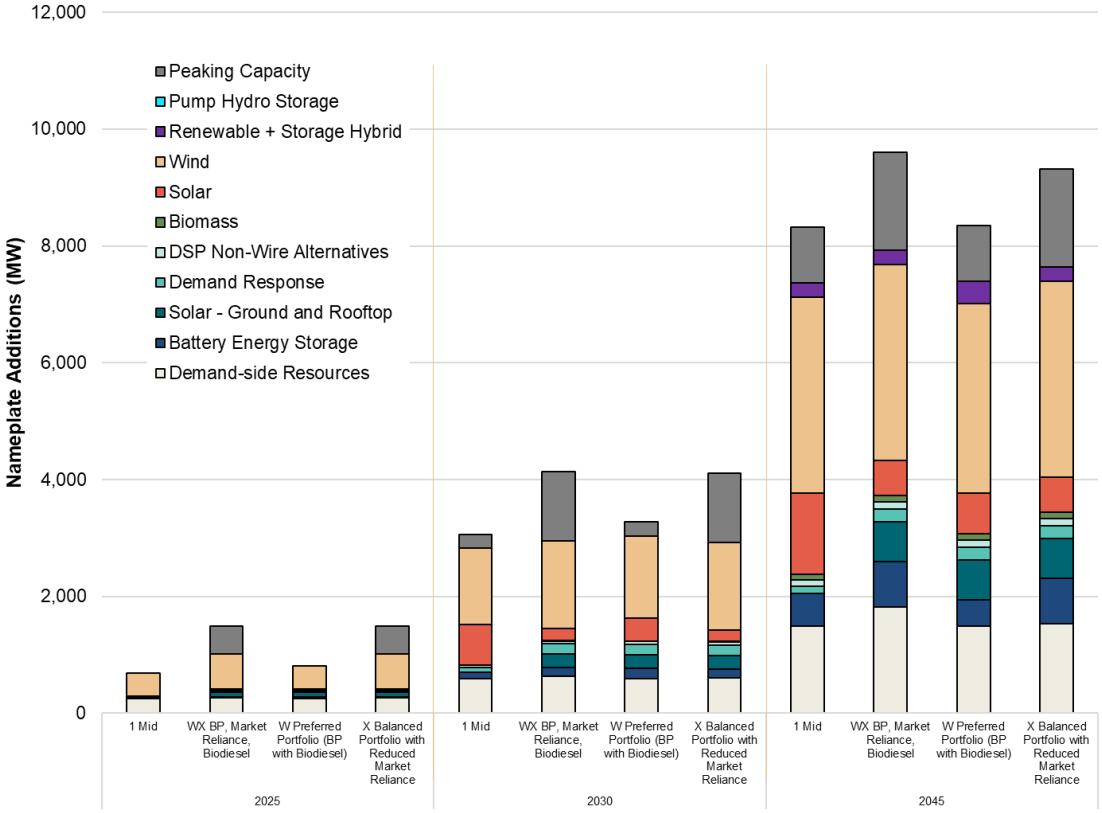
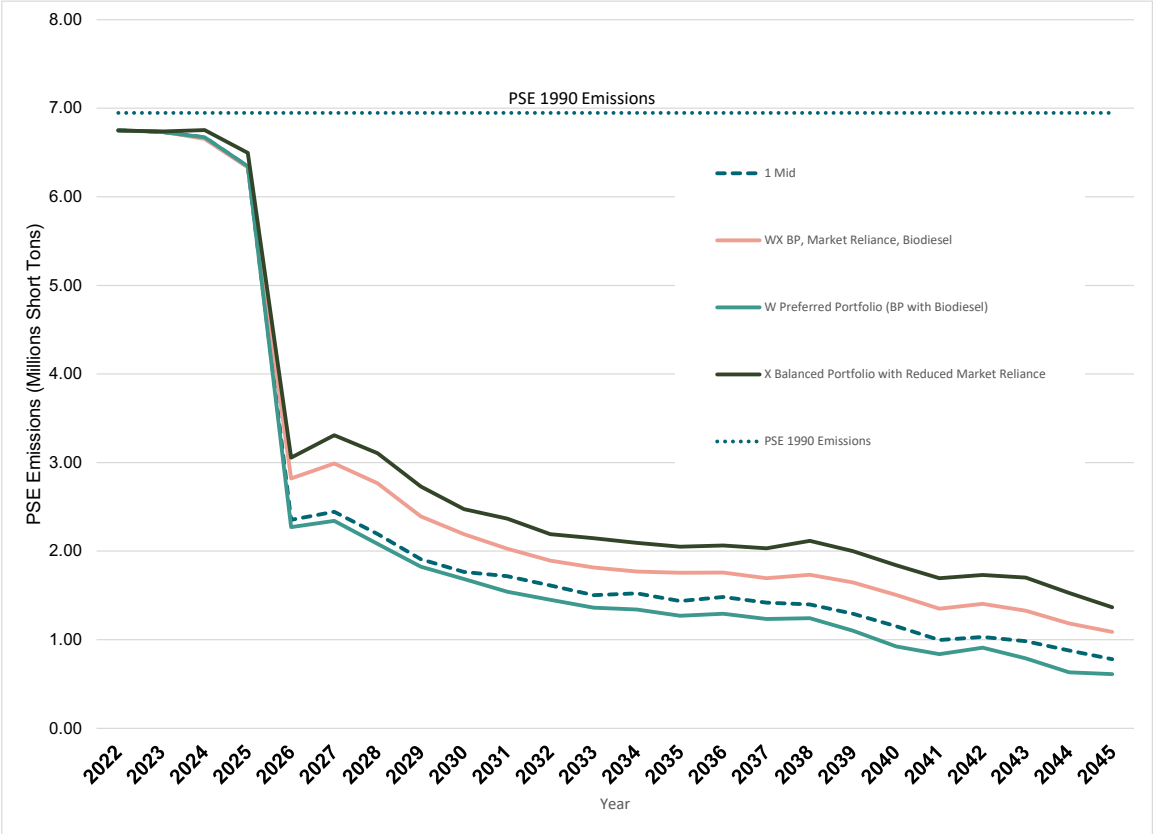


Figure 8-139: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

Resource Additions by 2045	1 Mid	WX BP, Market Reliance, Biodiesel	W Preferred Portfolio (BP with Biodiesel)	X Balanced Portfolio with Reduced Market Reliance
Demand-side Resources	1,497 MW	1,824 MW	1,784 MW	1,824 MW
Battery Energy Storage	550 MW	775 MW	450 MW	775 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,066 MW	4,051 MW	4,066 MW
Biomass	90 MW	120 MW	105 MW	120 MW
Solar	1,393 MW	596 MW	696 MW	596 MW
Wind	3,350 MW	3,350 MW	3,250 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	250 MW	375 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Flexible Capacity	948 MW	1,677 MW	966 MW	1,677 MW

EMISSIONS. Figure 8-140 compares direct GHG emissions from Sensitivities WX, W and X to the Mid Scenario. For Sensitivity W, emissions decrease compared to the Mid Scenario, through use of biodiesel for peaking capacity resources. For Sensitivity X, emissions increase compared to the Mid Scenario due to increased additions of peaking capacity resources. Consistent with the findings of sensitivities W and X, reducing market purchases and using of biodiesel have opposite effects on overall portfolio emissions. The overall emissions of portfolio WX fall between W and X.

Figure 8-140: Portfolio GHG Emissions – Mid Scenario and Sensitivity WX, W and X



Y. Maximum Customer Benefit

Maximizing customer benefits is a complex task. Numerous customer benefit indicators exist, and often increasing the benefit of one indicator reduces the benefit of another. Therefore, PSE's approach to maximizing customer benefits was to model a wide range of possible portfolios, many of which maximized specific customer benefit indictors. Through isolating and maximizing specific customer benefit indicators, it is possible to see trade-offs in other customer benefits and opportunities to balance those tradeoffs.

The following list highlights portfolios that maximize specific customer benefit indicators:

- Mid Scenario – The Mid Scenario, in addition to providing a basis for comparison to other sensitivities, is designed to be among the lowest cost portfolios. Over the 24-year timeframe, the Mid Scenario is ranked fourth best in terms of portfolio cost. Sensitivities G, I and M rank higher, but have only marginally lower portfolio costs and all include unique inputs which bring their costs down. Portfolio cost is directly related to the energy

costs passed on to customers and should be minimized to keep energy burdens low. The AURORA portfolio model is an economic model which seeks to minimize cost; therefore, increasing other customer benefit indicators typically results in increased portfolio costs. In developing a preferred portfolio, PSE must balance portfolio cost with other customer benefit indicators.

- Sensitivity C – The distributed, transmission limited sensitivity maximizes utilization of distributed energy resources. Distributed energy resources provide significant transmission and distribution benefits, offsetting the need for long-distance transmission. In Sensitivity, C thermal resources were necessary to provide capacity during periods of peak demand resulting in higher emissions than most other portfolios. Distributed resources are also expensive compared to utility-scale resources, resulting in higher portfolio costs, but they offset potential transmission risk. Adding more distributed resources helps to optimize the customer benefit areas of environment and resiliency.
- Sensitivity N, the 100 percent renewable by 2030 sensitivity maximizes several customer benefit indicators through transitioning to a clean energy portfolio ahead of CETA targets. Sensitivity N2 (pumped hydro storage) obtains the highest rank for the 24-year timeframe for the customer benefit areas of Climate Change, Air Quality and Market Position. Sensitivity N1 (batteries) ties for the highest rank in Air Quality and achieves the highest rank in Resiliency. Sensitivity N1 uses batteries to provide capacity resulting in a much more resilient portfolio than Sensitivity N2, which relies on centralized pumped hydro storage for capacity. Early adoption of clean energy technologies carries significant benefits. However, these benefits are balanced by extremely high portfolio costs. Furthermore, both Sensitivities N1 and N2 score low in the Resource Adequacy customer benefit indicator area due to the reliance on short-term energy storage for capacity. These short-term energy storage resources are energy limited, exposing PSE's customers to risk in the event of long-duration peak events.

Other portfolios assessed in this IRP provide varying degrees of customer benefits. Results for these portfolios are available earlier in this chapter. Of particular importance, are the Balanced Portfolios (Sensitivities V, W and WX) which do not seek to maximize any single customer benefit, but to provide meaningful contributions to customer benefit indicators to develop a well-rounded, low-risk portfolio.

Z. No DSR

This sensitivity examines the value of conservation and demand response resources to the portfolio.

Baseline: Conservation resources are selected when they are cost-effective.
Sensitivity Z > No conservation or demand response measures are included.

KEY FINDINGS. Without demand response or conservation, the cost of the Mid Scenario portfolio increases by $2.48 billion, building additional solar and storage resources to reach CETA compliance, and building two additional frame peakers to maintain peak capacity.

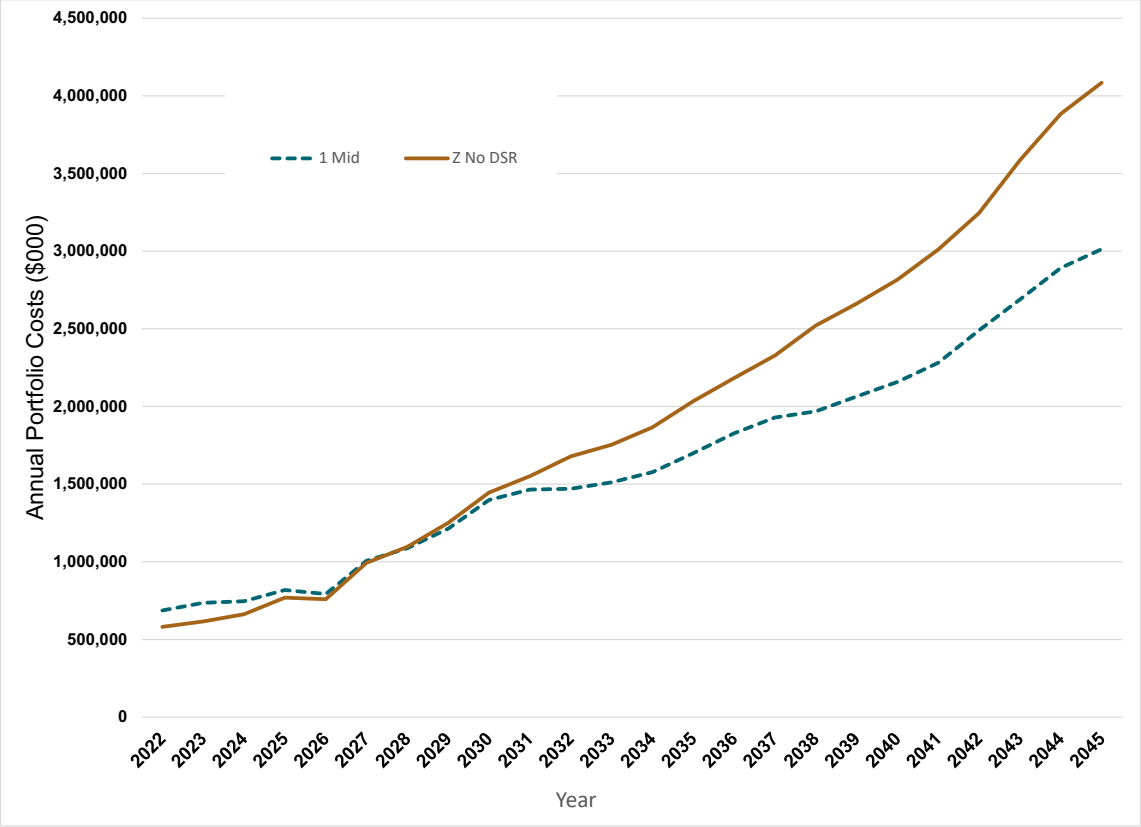
ASSUMPTIONS. Sensitivity Z keeps all the Mid Scenario modeling assumptions, except no conservation or demand response measures are included.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity Z and the Mid Portfolio are similar until 2030, when the removal of demand response and conservation from the portfolio reduce the costs of Portfolio Z. After 2030, growing demand that is unchecked by conservation measures combines with CETA renewable need to accelerate resource need and increase costs. Despite the up-front investment, DSR saves the Mid Scenario $2.48 billion by reducing demand and preventing the need for new resources, both renewable and thermal.

Figure 8-141: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Z

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Z	No DSR	$17.54	$5.56	$23.10	$2.48

Figure 8-142: Annual Portfolio Costs – Mid Scenario and Sensitivity Z



RESOURCE ADDITIONS. Figures 8-143 and 8-144 compares the nameplate capacity additions of the Mid Scenario and Sensitivity Z portfolios. To meet increased demand, Portfolio Z adds an additional two frame peakers (474 MW), 1,195 MW of eastern Washington solar, 250 MW of hybrid resources and 700 MW of 4- and 6-hour flow batteries by 2045. Solar builds begin to outpace the Mid Scenario as early as 2024, and a second round of builds enters late in the portfolio. For example, in Sensitivity Z, Washington wind capacity reaches 2,000 MW by 2039 with no further additions for the rest of the planning period compared to 1,500 MW of wind added in the Mid Scenario in 2039 which goes on to increase to 1,900 by 2045.

Figure 8-143: Portfolio Additions – Mid Scenario and Sensitivity Z

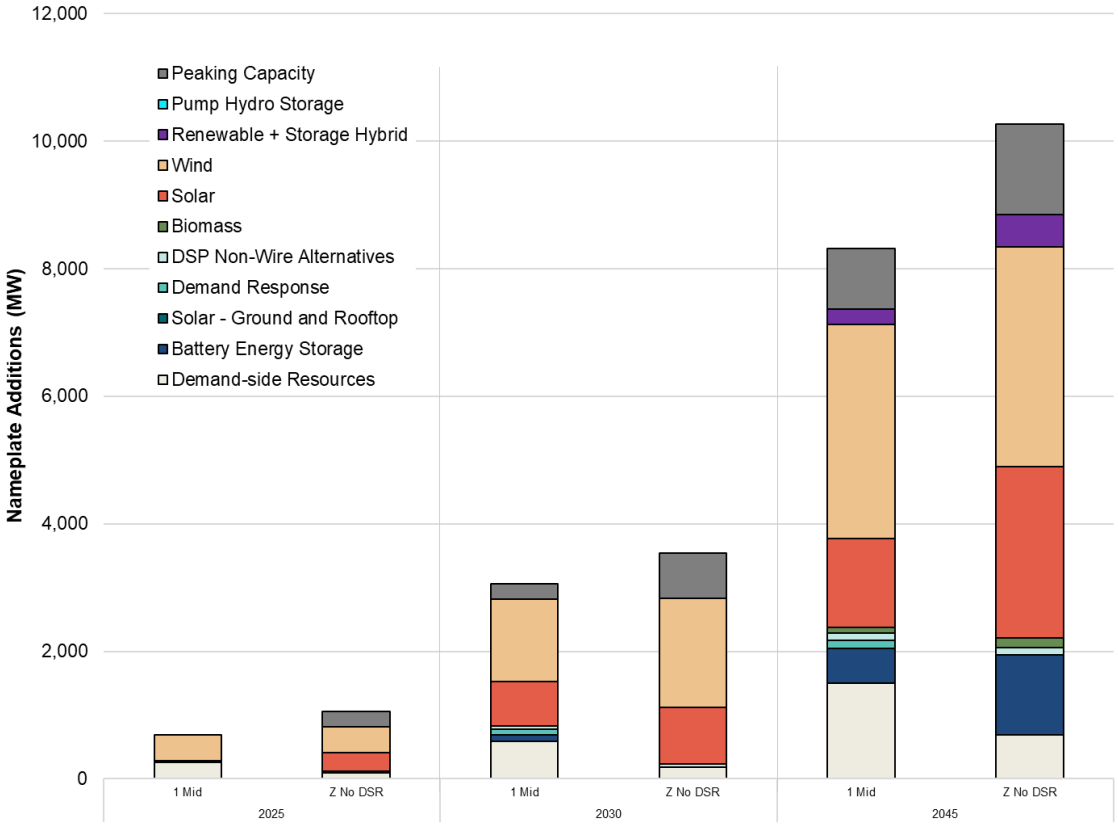


Figure 144: Portfolio Additions – Mid Scenario and Sensitivity Z

Resource Additions by 2045	1 Mid	Z No DSR
Demand-side Resources	1,497 MW	690 MW
Battery Energy Storage	550 MW	1,250 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	0 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,288 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,688 MW
Wind	3,350 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	1,422 MW

Other

AA. Montana Wind + Pumped Storage Hydro

This sensitivity examines the value of adding a hybrid resource early in the planning period.

Baseline: Hybrid resources are selected when they are cost-effective.
Sensitivity AA > A Montana wind plus pumped hydro storage hybrid resource is substituted for the eastern Montana wind resource added to the Mid Scenario in the year 2028.

KEY FINDINGS. Early addition of a hybrid Montana wind plus pumped hydro resource does not add meaningful value the portfolio. Portfolio costs are slightly higher and emissions remain the same or increase slightly. Peaking capacity additions are postponed by one or two years but are still added to the portfolio.

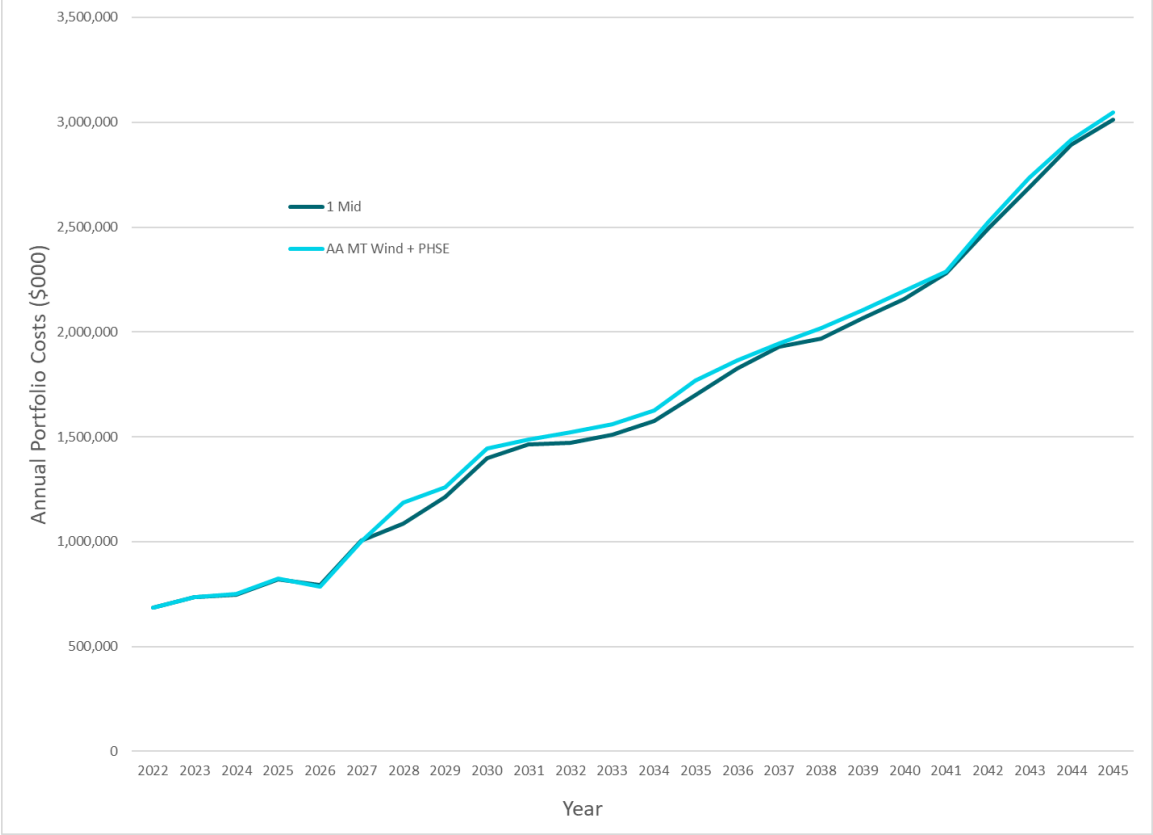
ASSUMPTIONS. Sensitivity AA keeps all the Mid Scenario modeling assumptions, except a Montana wind plus pumped storage hydro resource is forced into the portfolio in the year 2028.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity AA and the Mid Portfolio are similar except for the spike in revenue requirement in the year 2028 to purchase the Montana wind plus pumped hydro hybrid instead of the eastern Montana wind resource. The more costly revenue requirement of the hybrid resource is seen for the remainder of the planning period. Otherwise, portfolio costs are nearly identical.

Figure 8-145: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity AA

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
AA	MT wind + PHES	$15.84	$5.16	$20.99	$0.37

Figure 8-146: Annual Portfolio Costs – Mid Scenario and Sensitivity AA



RESOURCE ADDITIONS. Figures 8-147 and 8-148 compare the nameplate capacity additions of the Mid Scenario and Sensitivity AA portfolios. Resource additions are extremely similar between the two portfolios, the only notable differences being that Sensitivity AA adds the forced MT wind plus pumped hydro addition in 2028, 250 MW less independent storage and 300 MW less solar. Sensitivity AA adds peaking capacity on a slightly delayed schedule, but reaches the same amount of peaking capacity by 2045. Both portfolios select conservation Bundle 10.

Figure 8-147: Portfolio Additions – Mid Scenario and Sensitivity AA

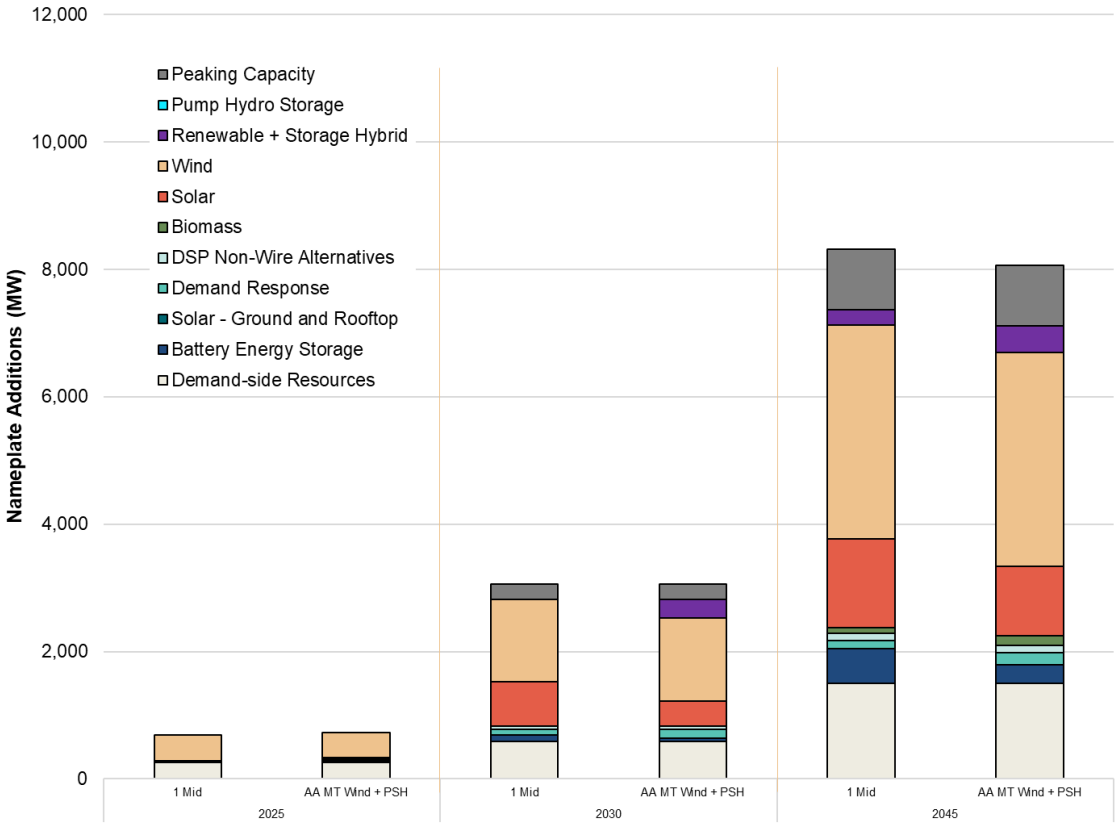
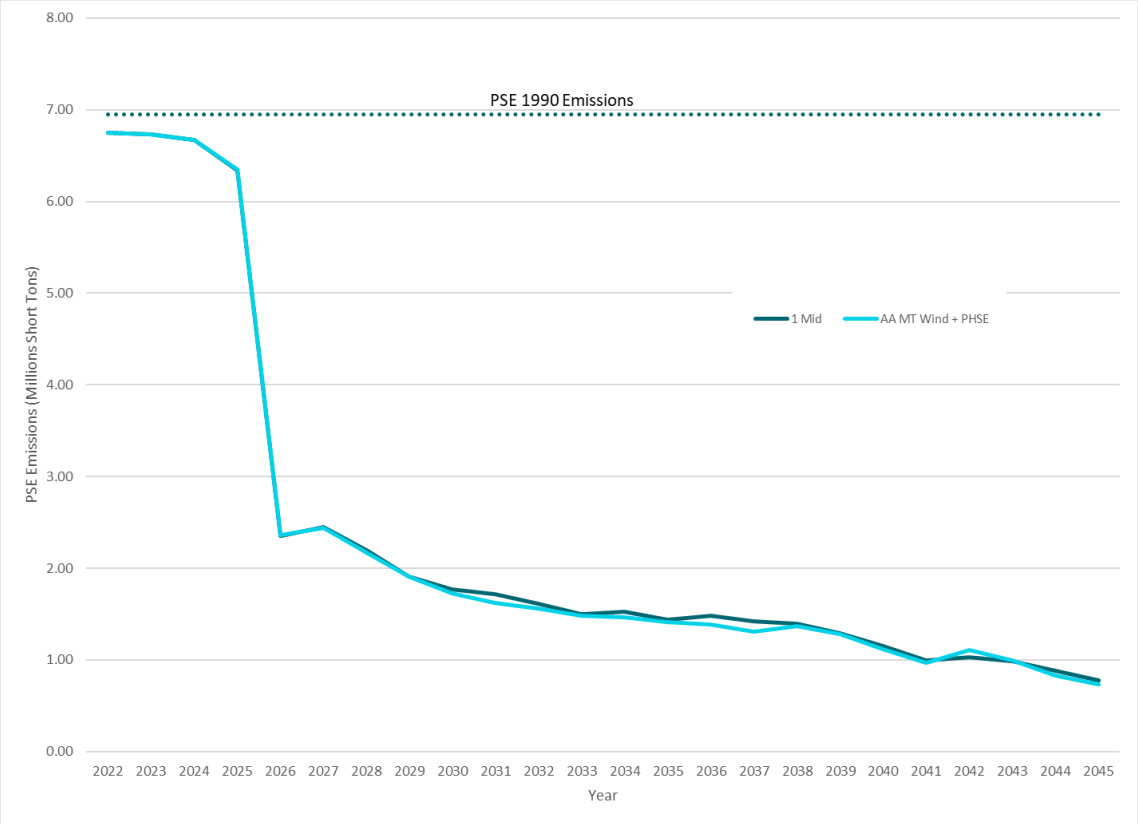


Figure 8-148: Portfolio Additions – Sensitivity AA

Resource Additions by 2045	1 Mid	AA MT Wind + PHES
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	300 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	182 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,594 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,094 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	425 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	948 MW

EMISSIONS. Figure 8-149 compares direct GHG emissions from Sensitivity AA to the Mid Scenario. Both portfolios have very similar direct emissions profiles.

Figure 8-149: Direct Emissions – Mid Scenario and Sensitivity AA



8. CUSTOMER BENEFITS ANALYSIS RESULTS

This section presents the results of the Customer Benefit Analysis. Not all portfolios were included in the Customer Benefit Analysis. To be included in the Customer Benefit Analysis, portfolios must meet the following criteria:

- Maintain consistency across demand and electric price forecasts
    - This criteria removed portfolios such as the Low and High Scenarios which varied demand and electric price inputs
- Must meet CETA requirements
    - This criteria removed portfolios such as Sensitivity T No CETA which does not include the CETA clean energy targets as a constraint.
- Represent current carbon regulation
    - This criteria removed portfolios such as Sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax, which models a federal carbon tax which is yet to be enacted.

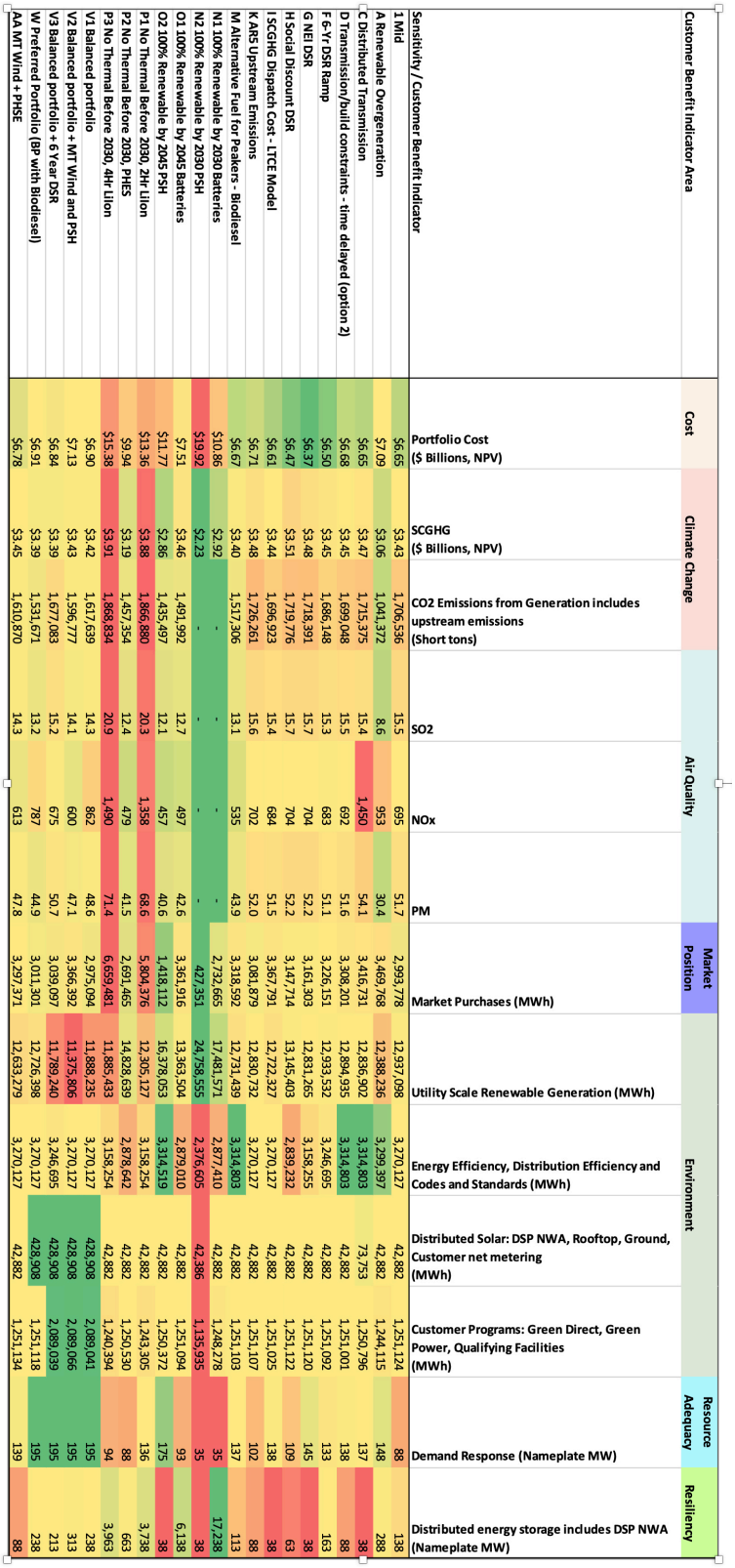
These criteria limit the analysis to portfolios that are solving for the same fundamental goals and are built from the same fundamental inputs. In other words, it allows for an “apples to apples” comparison between all the selected portfolios. The Customer Benefit Analysis is described earlier in this chapter.

Customer Benefit Analysis results are presented for two timeframes, 2031 and 2045. These timeframes correspond to the 10-year Clean Energy Action Plan and 24-year IRP planning horizons, respectively. There is value in understanding how customer benefits evolve over the planning horizon of a portfolio, and benefits which only manifest themselves in the latest years of the planning horizon may hold less value, as these years hold the most uncertainty.

All Customer Benefit Analysis results and accompanying calculations are also provided in Appendix H.

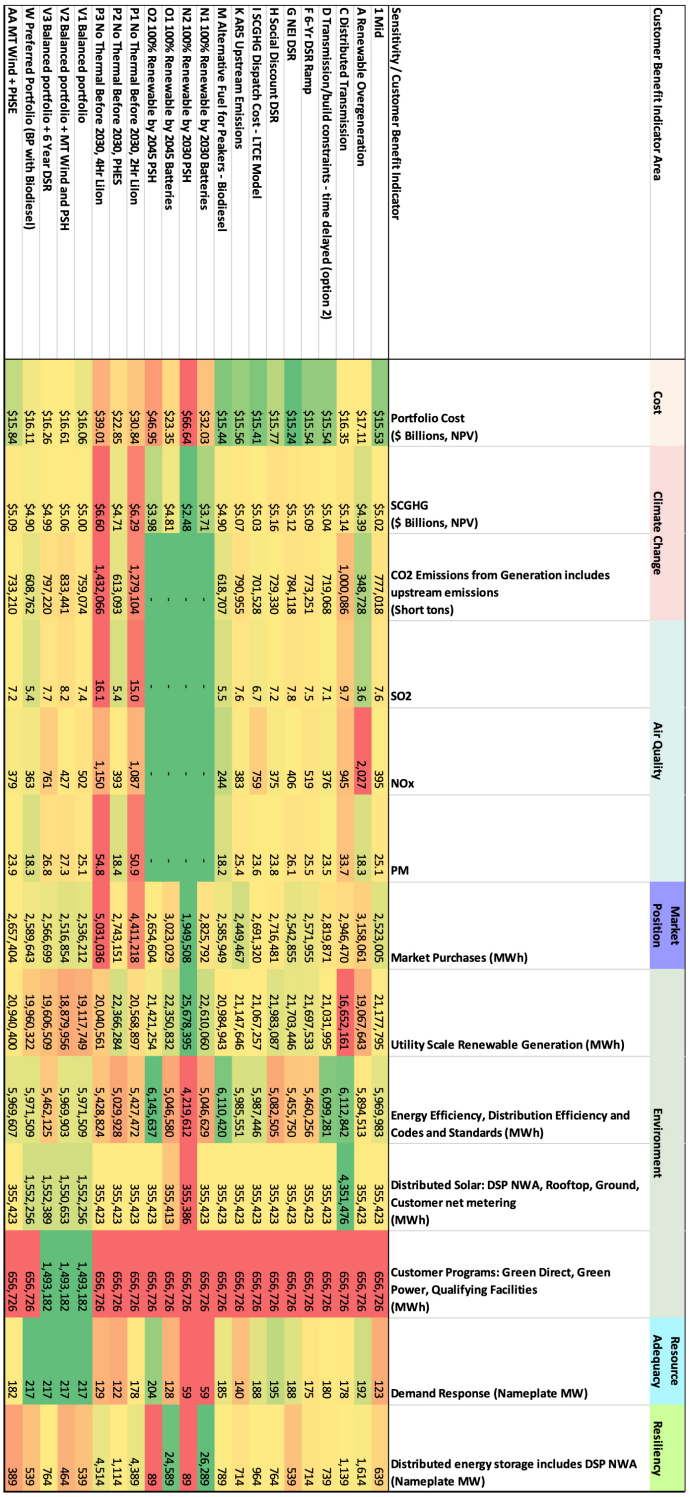
Figures 8-150 and 8-151 present the portfolio outputs selected to represent customer benefit indicators (CBIs) for the 10-year and 24-year timeframes, respectively. These outputs have been color coded, from red (least benefit) to green (most benefit).

Figure 8-150: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values



Customer Benefit Indicator Area	Cost	Climate Change	Air Quality			Market Position	Environment			Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	$6.65	$3.43	1,706,536	15.5	695	51.7	2,993,778	12,937,098	3,270,127	42,882	1,251,124	88	138
A Renewable Overgeneration	$7.09	$3.06	1,041,372	8.6	953	30.4	3,469,768	12,388,236	3,299,397	42,882	1,244,115	148	288
C Distributed Transmission	$6.65	$3.47	1,715,375	15.4	1,450	54.1	3,416,731	12,836,902	3,314,803	73,753	1,250,796	137	38
D Transmission/build constraints - time delayed (option 2)	$6.68	$3.45	1,699,048	15.5	692	51.6	3,308,201	12,894,935	3,314,803	42,882	1,251,001	138	88
F 6-Yr DSR Ramp	$6.50	$3.45	1,686,148	15.3	683	51.1	3,226,151	12,933,532	3,246,695	42,882	1,251,092	133	163
G NEI DSR	$6.37	$3.48	1,718,391	15.7	704	52.2	3,161,303	12,831,265	3,158,255	42,882	1,251,120	145	38
H Social Discount DSR	$6.47	$3.51	1,719,776	15.7	704	52.2	3,147,714	13,145,403	2,839,232	42,882	1,251,122	109	63
I SCGHG Dispatch Cost - LTCE Model	$6.61	$3.44	1,696,923	15.4	684	51.5	3,367,791	12,722,327	3,270,127	42,882	1,251,025	138	38
K AR5 Upstream Emissions	$6.71	$3.48	1,726,261	15.6	702	52.0	3,081,879	12,830,732	3,270,127	42,882	1,251,107	102	88
M Alternative Fuel for Peakers - Biodiesel	$6.67	$3.40	1,517,306	13.1	535	43.9	3,318,592	12,731,439	3,314,803	42,882	1,251,103	137	113
N1 100% Renewable by 2030 Batteries	$10.86	$2.92	-	-	-	-	2,732,665	17,481,571	2,877,410	42,882	1,248,278	35	17,238
N2 100% Renewable by 2030 PSH	$19.92	$2.23	-	-	-	-	427,351	24,758,555	2,376,605	42,386	1,135,935	35	38
O1 100% Renewable by 2045 Batteries	$7.51	$3.46	1,491,992	12.7	497	42.6	3,361,916	13,363,504	2,879,010	42,882	1,251,094	93	6,138
O2 100% Renewable by 2045 PSH	$11.77	$2.86	1,435,497	12.1	457	40.6	1,418,112	16,378,053	3,314,519	42,882	1,250,372	175	38
P1 No Thermal Before 2030, 2Hr Lilon	$13.36	$3.88	1,866,880	20.3	1,358	68.6	5,804,376	12,305,127	3,158,254	42,882	1,243,305	136	3,738
P2 No Thermal Before 2030, PHES	$9.94	$3.19	1,457,354	12.4	479	41.5	2,691,465	14,828,639	2,878,642	42,882	1,250,530	88	663
P3 No Thermal Before 2030, 4Hr Lilon	$15.38	$3.91	1,868,834	20.9	1,490	71.4	6,659,481	11,885,433	3,158,254	42,882	1,240,394	94	3,963
V1 Balanced portfolio	$6.90	$3.42	1,617,639	14.3	862	48.6	2,975,094	11,888,235	3,270,127	428,908	2,089,041	195	238
V2 Balanced portfolio + MT Wind and PSH	$7.13	$3.43	1,596,777	14.1	600	47.1	3,366,392	11,375,806	3,270,127	428,908	2,089,066	195	313
V3 Balanced portfolio + 6 Year DSR	$6.84	$3.39	1,677,083	15.2	675	50.7	3,039,097	11,789,240	3,246,695	428,908	2,089,039	195	213
W Preferred Portfolio (BP with Biodiesel)	$6.91	$3.39	1,531,671	13.2	787	44.9	3,011,301	12,726,398	3,270,127	428,908	1,251,118	195	238
AA MT Wind + PHSE	$6.78	$3.45	1,610,870	14.3	613	47.8	3,297,371	12,633,279	3,270,127	42,882	1,251,134	139	88

Figure 8-151: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values



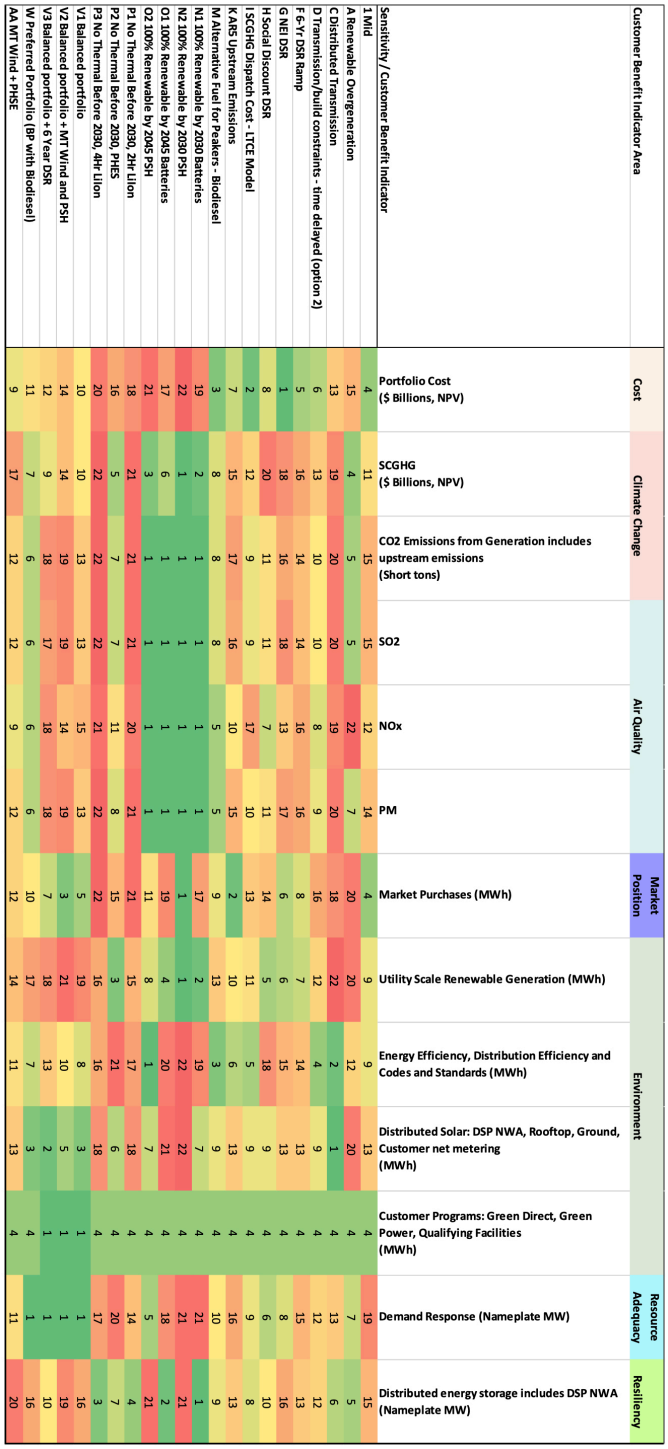
Customer Benefit Indicator Area	Sensitivity / Customer Benefit Indicator	Cost	Climate Change	Air Quality			Market Position	Environment			Resource Adequacy	Resiliency
		Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
	1 Mid	$15.53	$5.02	777,018	7.6	395	25.1	2,523,005	21,177,795	5,969,983	355,423	656,726	123	639
	A Renewable Overgeneration	$17.11	$4.39	348,728	3.6	2,027	18.3	3,158,061	19,067,643	5,894,513	355,423	656,726	192	1,614
	C Distributed Transmission	$16.35	$5.14	1,000,086	9.7	945	33.7	2,946,470	16,652,161	6,112,842	4,351,476	656,726	178	1,139
	D Transmission/build constraints - time delayed (option 2)	$15.54	$5.04	719,068	7.1	376	23.5	2,819,871	21,031,995	6,099,281	355,423	656,726	180	739
	F 6-Yr DSR Ramp	$15.54	$5.09	773,251	7.5	519	25.5	2,571,955	21,697,533	5,460,256	355,423	656,726	175	714
	G NEI DSR	$15.24	$5.12	784,118	7.8	406	26.1	2,542,855	21,703,446	5,455,750	355,423	656,726	188	539
	H Social Discount DSR	$15.77	$5.16	729,330	7.2	375	23.8	2,716,481	21,983,087	5,082,505	355,423	656,726	195	764
	I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.03	701,528	6.7	759	23.6	2,691,320	21,067,257	5,987,446	355,423	656,726	188	964
	K ARB Upstream Emissions	$15.56	$5.07	790,955	7.6	383	25.4	2,449,467	21,147,646	5,985,551	355,423	656,726	140	714
	M Alternative Fuel for Peakers - Biodiesel	$15.44	$4.90	618,707	5.5	244	18.2	2,585,949	20,984,943	6,110,420	355,423	656,726	185	789
	N1 100% Renewable by 2030 Batteries	$32.03	$3.71	-	-	-	-	2,825,792	22,610,060	5,046,629	355,423	656,726	59	26,289
	N2 100% Renewable by 2030 PSH	$66.64	$2.48	-	-	-	-	1,949,508	25,678,395	4,219,612	355,386	656,726	59	89
	O1 100% Renewable by 2045 Batteries	$23.35	$4.81	-	-	-	-	3,023,029	22,350,832	5,046,580	355,413	656,726	128	24,589
	O2 100% Renewable by 2045 PSH	$46.95	$3.98	-	-	-	-	2,654,604	21,421,254	6,145,637	355,423	656,726	204	89
	P1 No Thermal Before 2030, 2Hr Lion	$30.84	$6.29	1,279,104	15.0	1,087	50.9	4,411,218	20,568,897	5,427,472	355,423	656,726	178	4,389
	P2 No Thermal Before 2030, PHES	$22.85	$4.71	613,093	5.4	393	18.4	2,743,151	22,366,284	5,029,928	355,423	656,726	122	1,114
	P3 No Thermal Before 2030, 4Hr Lion	$39.01	$6.60	1,432,066	16.1	1,150	54.8	5,031,036	20,040,561	5,428,824	355,423	656,726	129	4,514
	V1 Balanced portfolio	$16.06	$5.00	759,074	7.4	502	25.1	2,536,212	19,117,749	5,971,509	1,552,256	1,493,182	217	539
	V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.06	833,441	8.2	427	27.3	2,516,854	18,879,956	5,969,903	1,550,653	1,493,182	217	464
	V3 Balanced portfolio + 6 Year DSR	$16.26	$4.99	797,220	7.7	761	26.8	2,566,699	19,606,509	5,462,125	1,552,389	1,493,182	217	764
	W Preferred Portfolio (BP with Biodiesel)	$16.11	$4.90	608,762	5.4	363	18.3	2,589,643	19,960,322	5,971,509	1,552,256	656,726	217	539
	AA MT Wind + PHSE	$15.84	$5.09	733,210	7.2	379	23.9	2,637,404	20,940,400	5,969,607	355,423	656,726	182	389

Figures 8-152 and 8-153 rank each of the selected portfolios on each of the CBIs for the 10-year and 24-year timeframes, respectively.

Figure 8-152: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks



Figure 8-153: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks



Figures 8-154 and 8-155 aggregate CBIs into customer benefit indicator areas and determine an overall portfolio rank from the seven CBI areas for the 10-year and 24-year timeframes, respectively.

Figure 8-154: 10-year Customer Benefit Analysis –
Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
12	1 Mid	6	14	15	6	6	19	12	11.1
9	A Renewable Overgeneration	14	4	8	20	15	6	7	10.6
20	C Distributed Transmission	5	17	18	19	8	11	18	13.7
15	D Transmission/build constraints - time delayed (option 2)	8	15	14	14	8	9	14	11.6
11	F 6-Yr DSR Ramp	3	14	12	12	10	14	11	10.8
16	G NEI DSR	1	19	18	11	10	7	18	11.8
18	H Social Discount DSR	2	20	18	10	10	15	17	13.0
17	I SCGHG Dispatch Cost - LTCE Model	4	13	13	18	10	10	18	12.3
19	K AR5 Upstream Emissions	9	19	16	9	8	16	14	13.1
8	M Alternative Fuel for Peakers - Biodiesel	7	8	7	15	8	11	13	9.7
5	N1 100% Renewable by 2030 Batteries	18	2	1	4	14	21	1	8.8
14	N2 100% Renewable by 2030 PSH	22	1	1	1	17	21	18	11.5
13	O1 100% Renewable by 2045 Batteries	16	11	6	16	10	18	2	11.2
4	O2 100% Renewable by 2045 PSH	19	3	4	2	10	5	18	8.7
21	P1 No Thermal Before 2030, 2Hr Lilon	20	21	21	21	18	13	4	16.8
7	P2 No Thermal Before 2030, PHES	17	5	5	3	11	20	5	9.4
22	P3 No Thermal Before 2030, 4Hr Lilon	21	22	22	22	20	17	3	18.1
2	V1 Balanced portfolio	12	10	13	5	7	1	8	8.0
6	V2 Balanced portfolio + MT Wind and PSH	15	10	8	17	8	1	6	9.2
3	V3 Balanced portfolio + 6 Year DSR	11	9	11	8	10	1	10	8.5
1	W Preferred Portfolio (BP with Biodiesel)	13	8	11	7	7	1	8	7.8
10	AA MT Wind + PHSE	10	12	10	13	8	8	14	10.6

Figure 8-155: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
14	1 Mid	4	13	14	4	9	19	15	11.1
13	A Renewable Overgeneration	15	5	11	20	14	7	5	11.0
20	C Distributed Transmission	13	20	20	18	7	13	6	13.8
11	D Transmission/build constraints - time delayed (option 2)	6	12	9	16	7	12	12	10.5
17	F 6-Yr DSR Ramp	5	15	15	8	10	15	13	11.5
10	G NEI DSR	1	17	16	6	10	8	16	10.5
8	H Social Discount DSR	8	16	10	14	9	6	10	10.3
3	I SCGHG Dispatch Cost - LTCE Model	2	11	12	13	7	9	8	8.8
12	K AR5 Upstream Emissions	7	16	14	2	8	16	13	10.8
1	M Alternative Fuel for Peakers - Biodiesel	3	8	6	9	7	10	9	7.5
6	N1 100% Renewable by 2030 Batteries	19	2	1	17	8	21	1	9.8
15	N2 100% Renewable by 2030 PSH	22	1	1	1	12	21	21	11.3
9	O1 100% Renewable by 2045 Batteries	17	4	1	19	12	18	2	10.4
5	O2 100% Renewable by 2045 PSH	21	2	1	11	5	5	21	9.4
21	P1 No Thermal Before 2030, 2Hr Lilon	18	21	21	21	14	14	4	16.0
18	P2 No Thermal Before 2030, PHES	16	6	9	15	9	20	7	11.6
22	P3 No Thermal Before 2030, 4Hr Lilon	20	22	22	22	14	17	3	17.0
4	V1 Balanced portfolio	10	12	14	5	8	1	16	9.3
16	V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	11.4
7	V3 Balanced portfolio + 6 Year DSR	12	14	18	7	9	1	10	10.0
2	W Preferred Portfolio (BP with Biodiesel)	11	7	6	10	8	1	16	8.3
19	AA MT Wind + PHSE	9	15	11	12	11	11	20	12.6

Figure 8-156 summarizes the overall portfolio rank for both the 10-year and 24-year timeframes. Generally, portfolios that ranked well in the 10-year timeframe also ranked well in the 24-year timeframe. However, there are notable exceptions, including Sensitivities I and P2.

Sensitivity I modeled the SCGHG as a dispatch cost in the LTCE model. Sensitivity I has a poorer overall rank in the 10-year timeframe but improves to be among the top-ranked portfolios in the 24-year timeframe. This suggests that Environmental and Resiliency benefits, which this portfolio ultimately scores well in, do not provide meaningful benefits until the end of the modeling horizon, and that other portfolios should be considered to deliver benefits as early as possible.

Sensitivity P2 forced the selection of pumped hydro storage resources before any flexible capacity could be added to the portfolio. Sensitivity P2 is a well-ranked portfolio in the 10-year timeframe but drops to near the bottom of the rankings in the 24-year time horizon. This suggests that too much focus on early adoption of storage resources is a costly endeavor that sets up the portfolio to be reliant on large quantities of market purchases to charge the storage resources.

Figure 8-156: Overall Portfolio Rank by 10-year and 24-year Timeframe

	10-year	24-year
1 Mid	12	14
A Renewable Overgeneration	9	13
C Distributed Transmission	20	20
D Transmission/build constraints - time delayed (option 2)	15	11
F 6-Yr DSR Ramp	11	17
G NEI DSR	16	10
H Social Discount DSR	18	8
I SCGHG Dispatch Cost - LTCE Model	17	3
K AR5 Upstream Emissions	19	12
M Alternative Fuel for Peakers - Biodiesel	8	1
N1 100% Renewable by 2030 Batteries	5	6
N2 100% Renewable by 2030 PSH	14	15
O1 100% Renewable by 2045 Batteries	13	9
O2 100% Renewable by 2045 PSH	4	5
P1 No Thermal Before 2030, 2Hr LiIon	21	21
P2 No Thermal Before 2030, PHES	7	18
P3 No Thermal Before 2030, 4Hr LiIon	22	22
V1 Balanced portfolio	2	4
V2 Balanced portfolio + MT Wind and PSH	6	16
V3 Balanced portfolio + 6 Year DSR	3	7
W Preferred Portfolio (BP with Biodiesel)	1	2
AA MT Wind + PHSE	10	19

As shown in Figure 8-156, the Customer Benefit Analysis suggests Sensitivity M as the portfolio that provides the greatest benefit to PSE customers in the 24-year IRP timeframe. PSE recognizes that this portfolio has many desirable attributes including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits. Therefore, PSE has selected Sensitivity W Balanced Portfolio with Biodiesel as the preferred portfolio. Sensitivity W provides many of the same benefits as Sensitivity M, but also includes greater investment in distributed energy resources. Furthermore, Sensitivity W is shown to provide the greatest benefit in the 10-year CEAP timeframe. This shows that early investment in these distributed resources provides benefits over the entire span of the modeling horizon, whereas Sensitivity M benefits are realized most strongly in the later years.

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. To achieve this purpose, PSE runs select portfolios through 310 simulations, or draws,[7] that vary power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can quantify the risk of each portfolio. Four different portfolios were tested in the stochastic portfolio analysis. Figure 8-xx describes the four different portfolios.

Figure 8-157: Portfolios Tested for Stochastic Analysis

Portfolios Tested for Stochastic Analysis		
1	Mid Scenario	This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS.
W	Balanced Portfolio with Alternative Fuel for Peakers	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel, along with a reduced access to the Mid-C market for both sales and purchases.
Z	No DSR	This portfolio is from the no DSR sensitivity.

7 | Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power and Conservation Council (NPCC) in its power plans.

PSE also looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets. The annual volatility data can be found in Appendix H, Electric Analysis Inputs and Results.

Stochastic Results

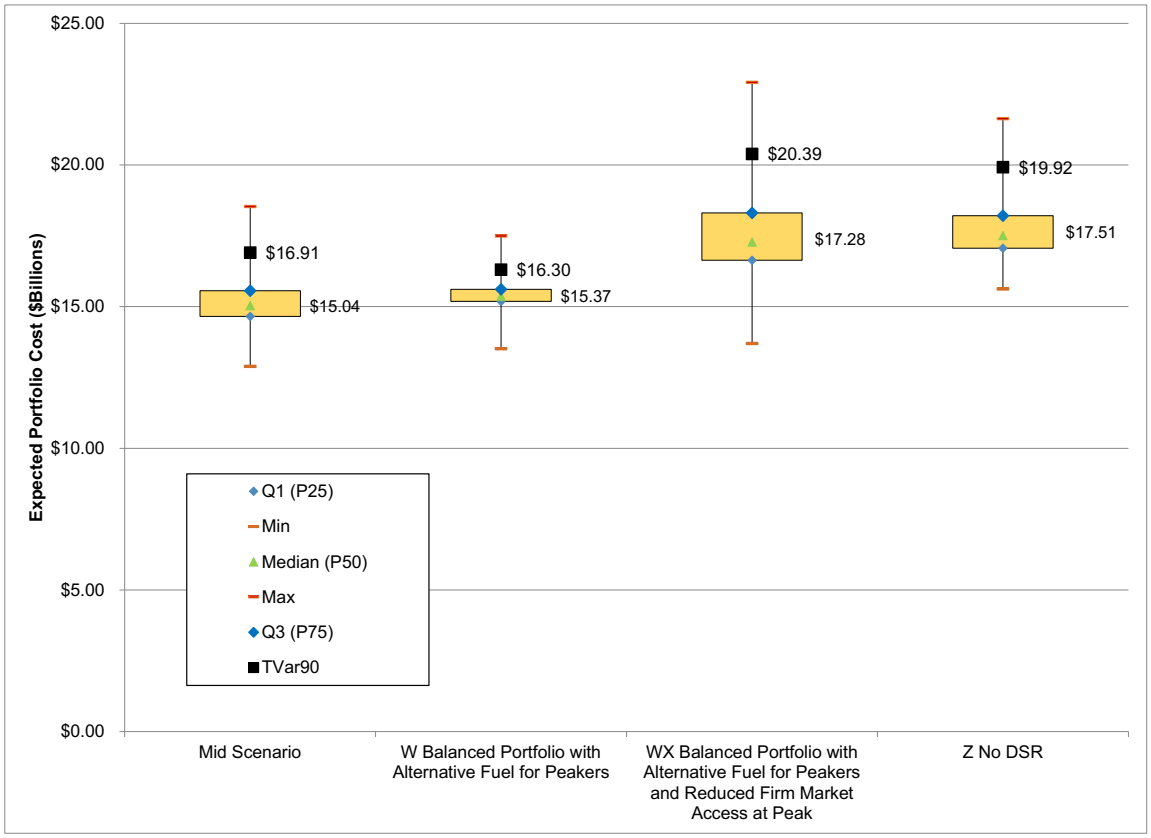
PSE's approach to the electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information available through the Request for Proposal and other acquisition processes. Nevertheless, the result of the risk simulation provides an indication of portfolio costs risk range under varying input assumptions. Figure 8-158 shows a comparison of the 24-year levelized costs for the deterministic run, the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for all 4 portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model run for 3 of the portfolios except for the No DSR portfolio.

Figure 8-158: Portfolio Costs across 310 Simulations

		24-year Levelized Costs (Billion $)					
Revenue Requirement	Portfolio	Deterministic	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$15.53	--	$15.18	--	$16.91	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$16.10	$0.57	$15.42	$0.24	$16.30	($0.60)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$18.78	$3.25	$17.53	$2.34	$20.39	$3.49
Z	No DSR	$17.54	$2.01	$17.74	$2.56	$19.92	$3.01

Figure 8-159 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs and the horizontal axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

Figure 8-159: Range of Portfolio Costs across 310 Simulations



Key results of the analysis include:

- The interquartile range for Sensitivity W is comparatively narrow and has the lowest TailVar90 at $16.3 billion, suggesting that the overall expected portfolio costs are the least variable compared to the other portfolios.
- Sensitivity WX has the widest interquartile range and the highest TailVar90 at $20.4 billion, suggesting the highest risk in portfolio costs variability. With the reduction of market access, the risk shifts from Mid-C market price volatility to natural gas price volatility. Thermal resources replace the energy that is no longer available from the market. Portfolio fuel costs may increase or decrease depending on the simulation.
- In Sensitivity Z, the mean of the 310 simulations is $17.7 billion, which is $0.2 billion higher than the deterministic portfolio costs. In comparison to the Mid Scenario, the mean and the deterministic portfolio costs are higher for Sensitivity Z. This suggests that demand-side resources reduce both cost and market risk in portfolios.

Figures 8-160 to 8-161 below show the frequency distribution of portfolio cost for selected portfolios. Portfolio cost results for each simulation are sorted into “bins,” with each bin containing a narrow range of expected portfolio costs.

Figure 8-160 compares the Mid Scenario to Sensitivity W. The shorter right-hand tail and lower TailVar90 value of Sensitivity W indicate there is less risk associated with Sensitivity W than the Mid Scenario, despite the higher average portfolio cost.

Figure 8-160: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity W

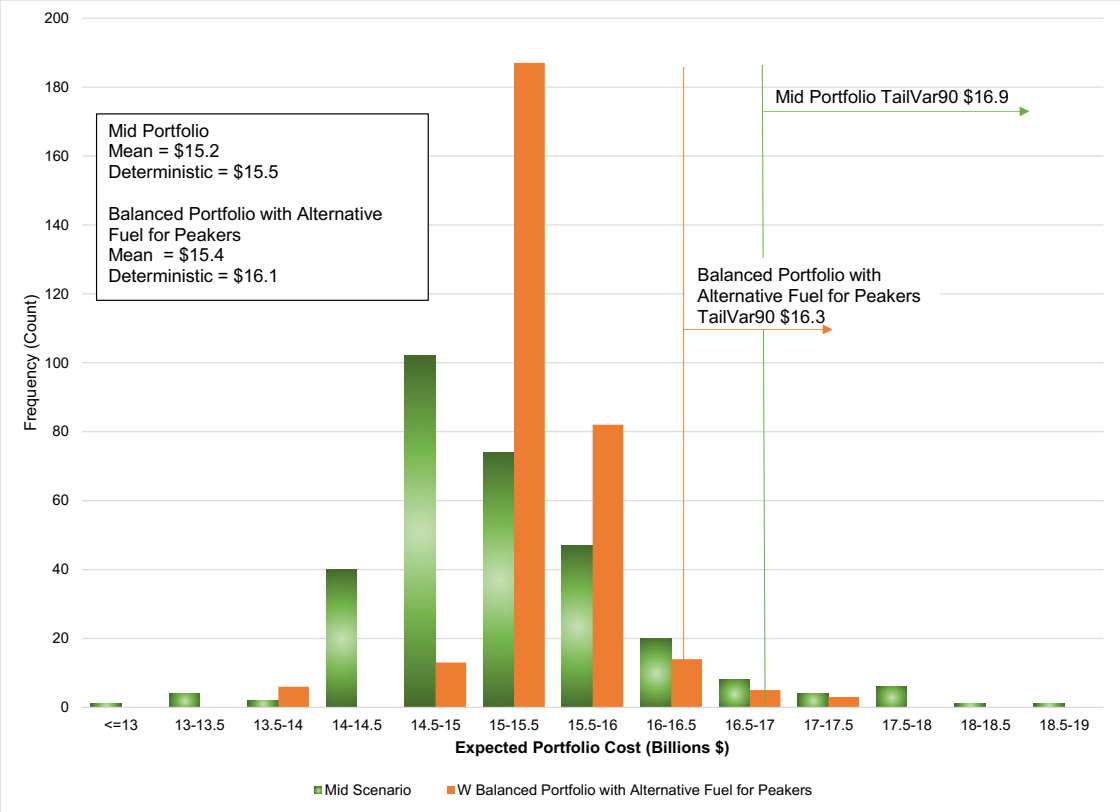


Figure 8-161 compares the Mid Scenario with Sensitivity Z. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity Z indicate the demand-side resources are an effective way to reduce both portfolio cost and risk.

Figure 8-161: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity Z

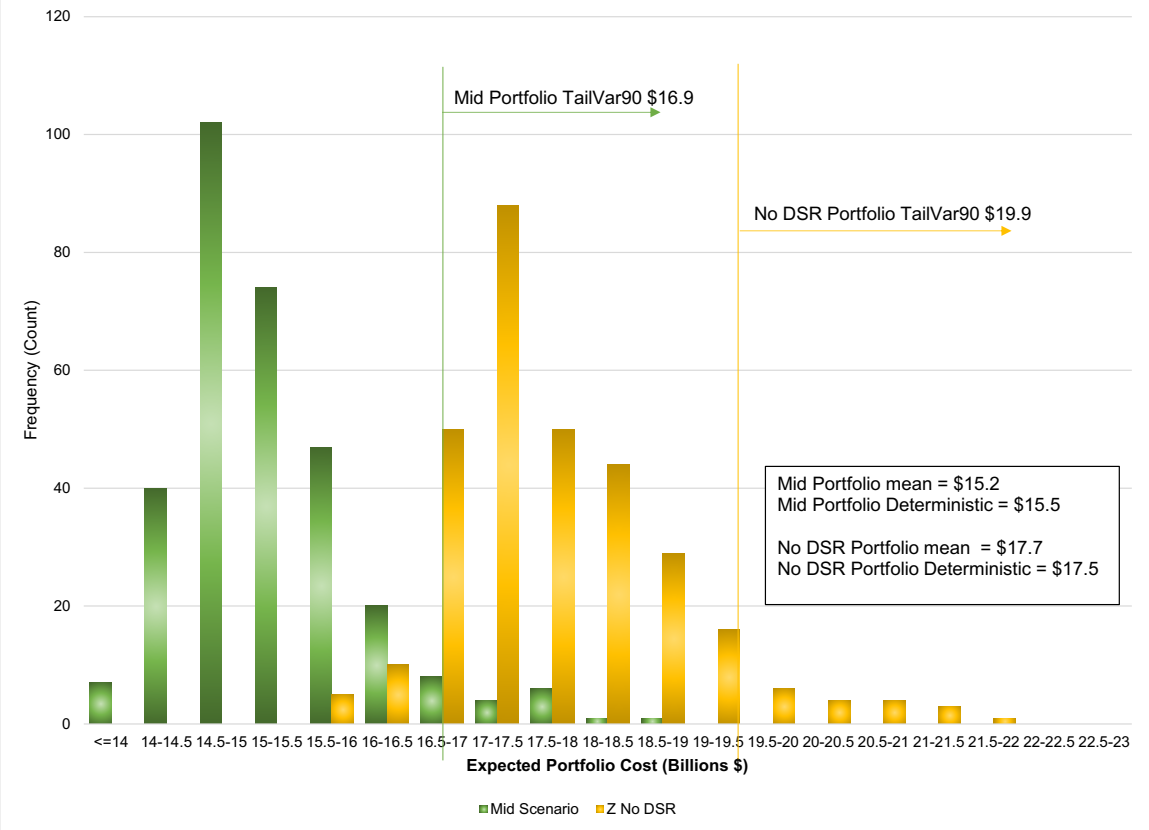
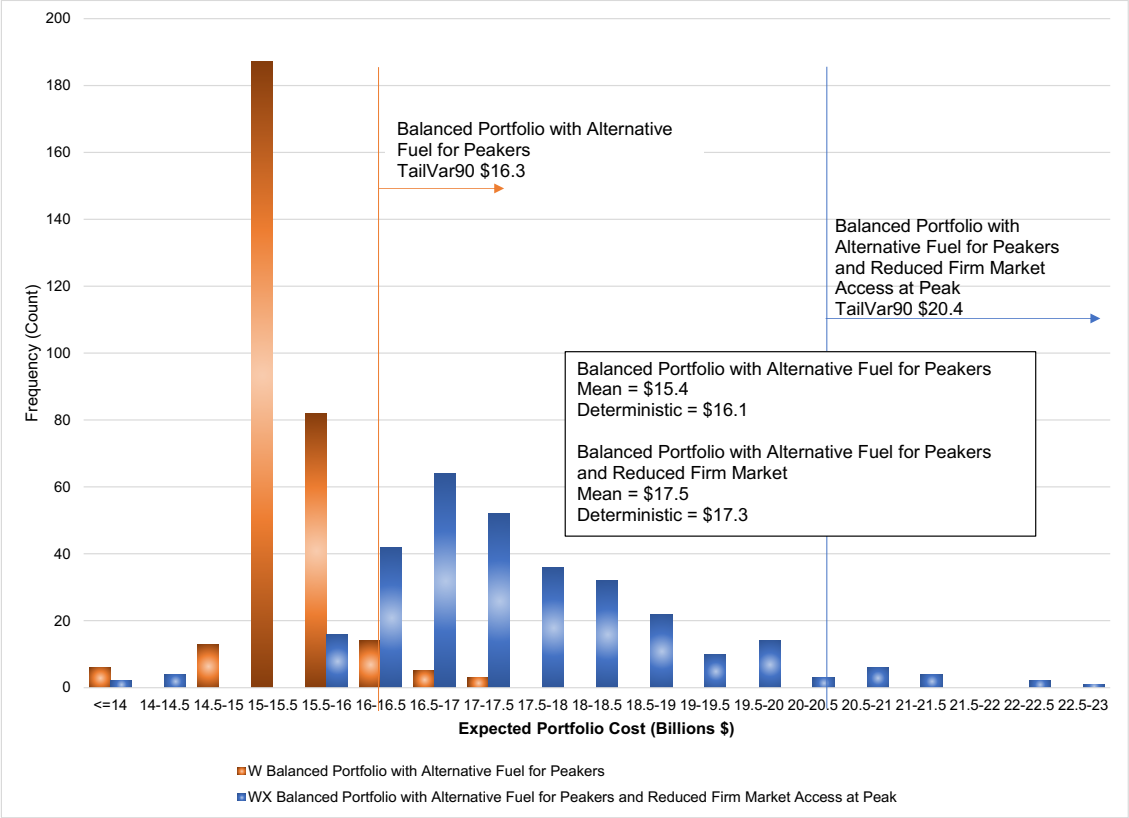


Figure 8-162 compares Sensitivity W with Sensitivity WX. The only difference between Sensitivity W and Sensitivity WX is the reduced access to market purchases during peak demand in Sensitivity WX. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity WX show that it is both more costly and riskier than the Sensitivity W. As stated above, this added risk is associated with volatility of natural gas prices to fuel thermal resources used to replace market purchases during peak demand. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

Figure 8-162: Frequency Histogram of Expected Portfolio Cost (Billions $) – Preferred Portfolio vs. Preferred Portfolio with Market Reduction



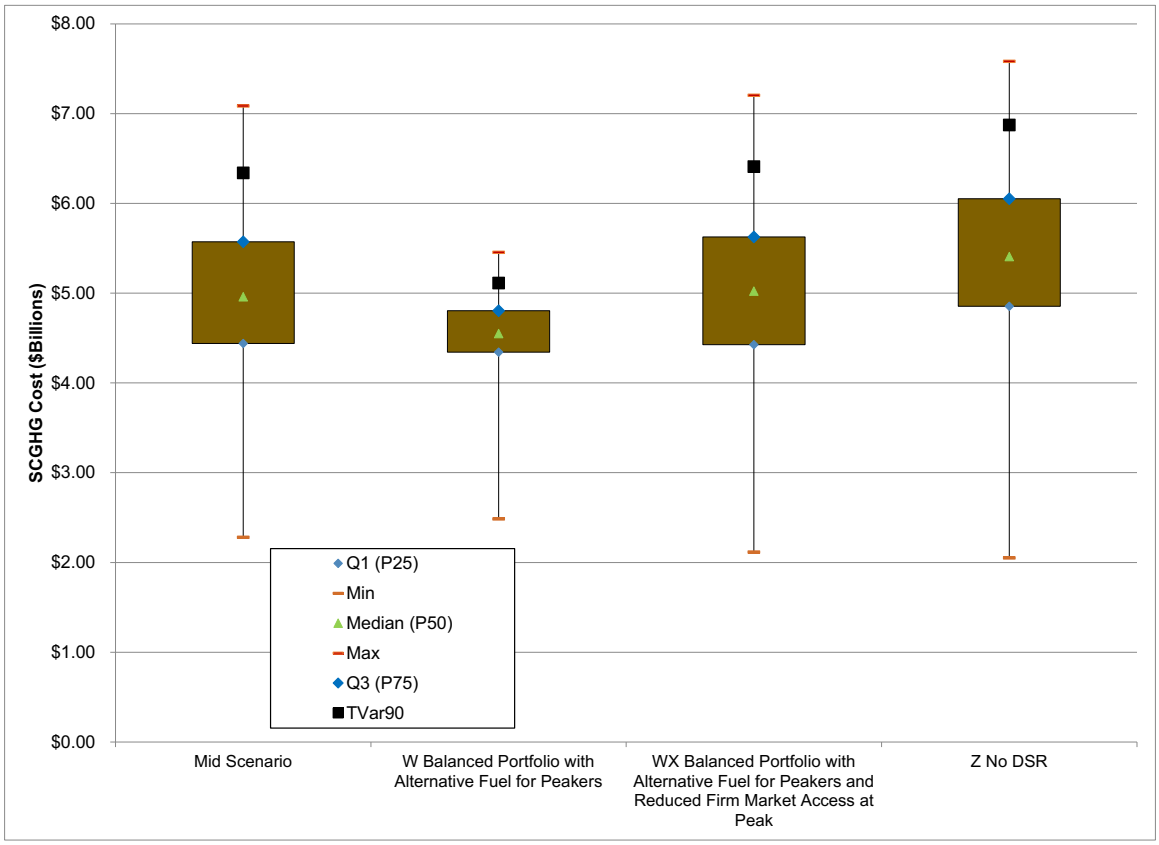
In addition to the expected portfolio costs, PSE also evaluated the expected SCGHG. Figure 8-163 and 8-164 below show a comparison of the 24-year levelized emissions costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of all 4 portfolios.

Results are similar to the portfolio cost results discussed above. Sensitivity W shows the narrowest, and therefore least-risk, range of SCGHG.

Figure 8-163: SCGHG across 310 Simulations

		24-year Levelized Costs (Billion $)					
SCGHG	Portfolio	Emissions	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$5.09	--	$4.98	--	$4.98	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$4.96	($0.13)	$4.54	($0.44)	$4.54	($0.44)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$4.74	($0.35)	$5.02	$0.47	$6.41	$1.43
Z	No DSR	$5.56	$0.47	$5.42	$0.41	$6.87	$1.90

Figure 8-164: Range of SCGHG across 310 Simulations



10. ELECTRIC DELIVERY SYSTEM ANALYSIS

Overview

PSE's electric delivery system is responsible for delivering electricity safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, we must do the following.[8]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at a local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Meet the interconnection needs of independent power generators and customers that choose to connect and provide energy to our system.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest applicable and approved version of the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kilovolts (kV) and above – is planned, operated and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent or more specific than NERC standards at times.

8 / These obligations are defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; WAC 480-100 Electric Companies; WAC 480-108 Electric companies - Interconnection with Electric Generators; WAC 480-100-358:398 Part VI Safety and Standard Rules; National Electric Safety Code (NESC) Parts 1, 2 and 3; NERC Reliability Standards; WECC Regional Reliability Standards; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; Washington Industrial Safety and Health Administration; National Electric Code; and Institute of Electrical and Electronics Engineers.

Ever more important today is to ensure that the system is flexible enough to adapt to coming changes. Smart and flexible equipment, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward, and PSE's electric delivery system needs to be prepared to integrate them for the benefit of our customers. Figure 8-XX depicts PSE's grid modernization framework for electric system improvements.

Figure 8-165: Grid Modernization Framework



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

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and the root causes of historic outages. External inputs include service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term and short-term planning. Typically, utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

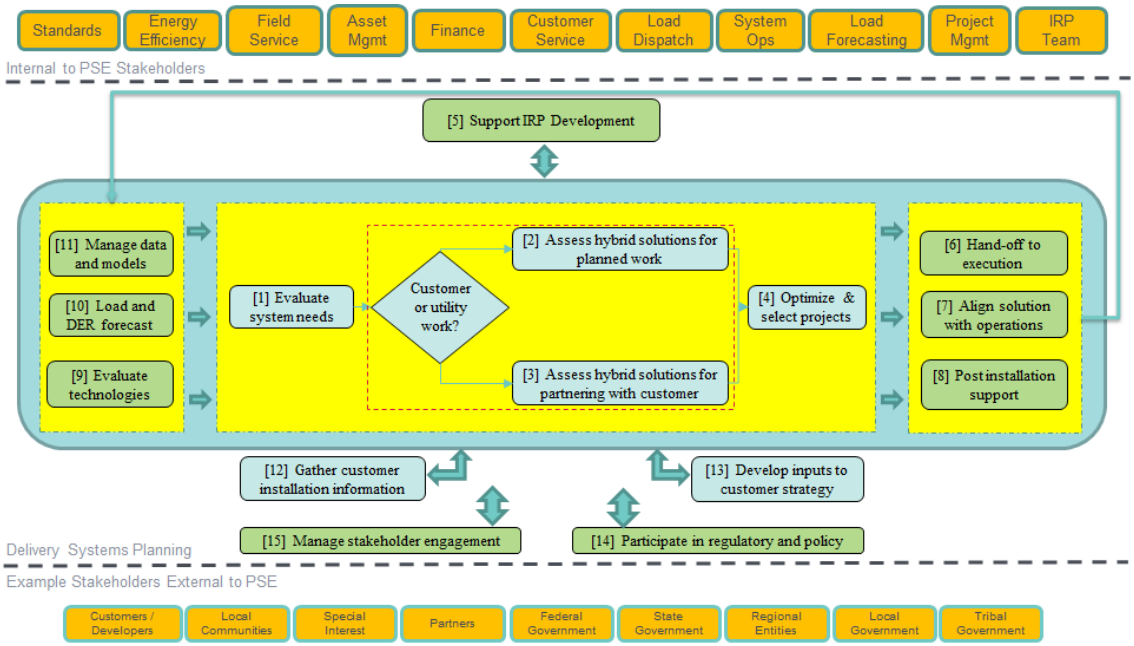
Key Findings

PSE's 10-year plan is included as Appendix M of this IRP.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 8-166 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 8-166: PSE Delivery System Planning Operating Model



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

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area. For example, PSE has requests from several data centers, industrial facilities, etc., that plan to connect in the next few years with projected loads between 5 and 15 MW.

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

RESOURCE INTEGRATION. FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new generation facility, whether it is owned and operated by PSE or by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region. Also, if natural gas is the generation feedstock, large plants will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life and is incapable of supporting the digitization of the grid includes substation assets, circuit breakers and remote terminal units. Assets whose age and condition create reliability and resilience issues include direct buried high molecular weight underground distribution cable, poles and cross arms, and substation transformers.



RELIABILITY. Improving areas across the delivery system to minimize both the total number and duration of outages is important to customers today. This will become increasingly important in a modern grid as we anticipate customers will be even more reliant on electrical power as transformation such as transportation conversions continue to occur.

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

DISTRIBUTED ENERGY RESOURCES. At sufficient scale, distributed energy resources such as roof-top solar can reduce demand or provide operational flexibility. If uncontrolled, they can increase demand such as charging batteries during peak times or triggering voltage or power quality concerns if there are too many or they don't operate appropriately.

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

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outage experience, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements bring the most customer benefit. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. PSE gives additional consideration to system enhancements that will improve resiliency, such as the ability to deliver electricity via a second line, possibly from another substation, to make the grid more self-healing. Programs are also in place to address aging infrastructure by replacing poles and other components that are nearing the end of their useful life.

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy and Grid Modernization strategy, are also included in the system evaluation. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As the transportation projects develop through design, engineering and construction, PSE works with the local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs. PSE also collects public input regarding the need for infrastructure improvement through the PSE and WUTC complaint process, as well as through open forums

that result from less than satisfactory service. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost.

PSE actively reviews and evaluates new technologies that can support delivery system needs. These technologies are identified, cataloged, and evaluated by an internal, cross-functional group of experts for business alignment, potential value, and feasibility. Cybersecurity continues to be a top consideration when evaluating products that are new in the market. PSE also seeks to leverage existing investments wherever possible when selecting and implementing new technologies. Following a successful evaluation, new technologies can be tested in a lab or piloted *in situ*. Results are documented and reviewed by all impacted teams. As new technologies complete the pilot process, they can be deployed at scale to meet the delivery system needs described above.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-167 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT,[9] which then creates the full understanding of all the benefits and risks.

[9] / *Investment Decision Optimization Tool which is a software tool called Folio by PwC.*

Figure 8-167: Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
Synergi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS; load approvals; load forecast	Predicted system performance
Power World Simulator – Power Flow	Electric network modeling	Electric transmission infrastructure from WECC base case and load/generation characteristics from CIS; load approvals; load forecast	Predicted system performance
Electric Predictive Spreadsheet	Electric outage predictive analysis	Electric outage history from SAP	Predicted outage savings
Estimated Unserved Energy (EUE) Spreadsheet	Electric financial analysis	Estimated project costs; hourly load data from EMS; load growth scenarios from load forecast	Net Present Value; income statement; load growth vs. capacity comparisons; EUE
Asset Management Assessment	Electric maintenance analysis	Electric infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

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

To simulate the performance of the electric transmission system, PSE primarily uses Power World Simulator. This simulation program uses a transmission system model that encompasses infrastructure across 11 western states, two provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models are collected, coordinated and distributed through regional organizations that have included ColumbiaGrid, NorthernGrid, and WECC (one of eight regional reliability organizations under NERC). These power system study

programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards. While PSE utilizes a regional model for system evaluation and coordination, the focus is on local concerns and projects. Appendix J, Regional Transmission Resources, describes regional transmission planning and the role of the Regional Planning Organization (RPO). PSE has been a member of the ColumbiaGrid since 2006, succeeded by NorthernGrid in 2020. The RPO has had substantial responsibilities for transmission planning, reliability and other development services in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of eight utilities that coordinate regional planning through the RPO, which has provided transparency and encourages broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system, or in the case of transmission, provided by WECC. For electric infrastructure, this includes conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment, voltage settings, and any DER that is controllable on the system. Next, PSE identifies customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual circuit readings. DERs that are not controllable require PSE to consider the load without them operating due to the need for the system to serve as backup. Finally, PSE takes into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads. DERs that are on the system that may not be controllable may serve as solutions if and when control and aggregation technologies are added.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 8-168. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission and distribution, as well as for capacity and reliability. A "need" is identified when performance criteria is not met.

Figure 8-168: Performance Criteria for Electric Delivery System

Electric delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (normal winter peak, extreme winter peak) with expected reliability conservation
The nature of service and level of reliability that each type of customer has contracted for (firm or interruptible)
The minimum voltage that must be maintained in the system (no more than 5 percent below standard voltage)
The maximum voltage acceptable in the system (no more than 5 percent above standard voltage)
Thermal limits of equipment used to deliver power to load centers and transmission customers (per PSE Transmission and Distribution Planning Guidelines)
The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (100 percent compliance) and all required planning scenarios and sensitivities.
The historical or future reliability performance that may be unacceptable or beyond benchmarks which may be caused by aging infrastructure, vegetation, third party damage, equipment condition, or animal interference.
The ability to remove equipment from service for maintenance and provide flexibility for outage restoration.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursing electrification, distributed energy resources dependency at the local circuit level, and deferral of traditional infrastructure network. PSE expects that customers will have higher expectations of reliability and economic impact of outages to be greater, requiring a delivery system with better reliability and resiliency than today. PSE expects delivery system planning margins to increase to account for operating concerns relating to distributed energy resource including behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response have historically incorporated outputs generically, but these assumptions while appropriate for resource planning may not be appropriate for circuit level decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE meets with jurisdictions in various forums such as quarterly roundtable discussions that include other utilities and agencies and in formal public presentations required through agreement or local regulation in order to gather input about concerns and coordinate solutions. For example,

PSE and the City of Bellevue meet annually to exchange plans related to community development and utility system improvements, which provides an opportunity for interested stakeholders to ask questions and raise issues and concerns. Similarly, PSE engages in a multi-year coordination with Bainbridge Island stakeholders to discuss reliability and gather input regarding improvements.

Solutions Assessment and Criteria

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

Figure 8-169: Alternatives for Addressing Electric Delivery System

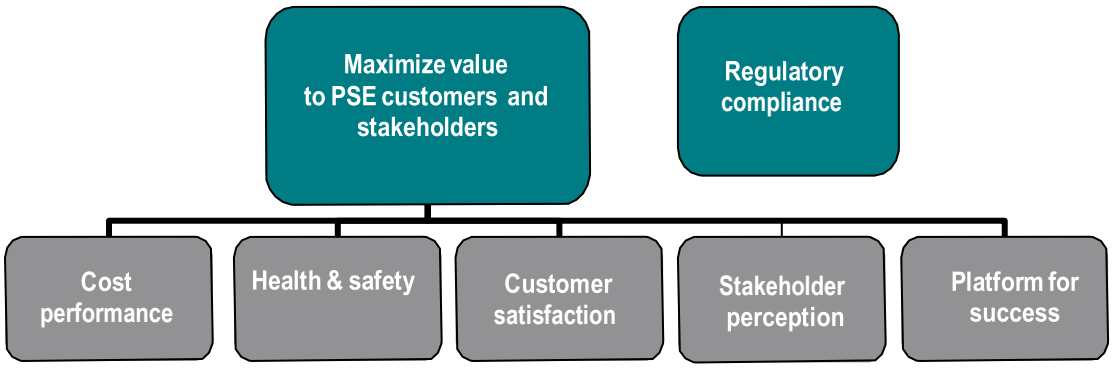
ELECTRIC SYSTEM ALTERNATIVES	
Add energy source	Substation; Distributed energy resource
Strengthen feed to local	New conductor; Replace conductor
Improve existing facility	Substation modification; Expanded right-of-way; Uprate system; Modify automatic switching scheme
Load reduction	Rebalance load; Fuel switching; Battery storage; Natural gas conversion; Conservation/Demand response; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Energy storage can be incorporated in both large-scale and small-scale projects (such as paired with rooftop solar DERs). Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases. Additionally, reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. Finally, in sufficient quantities, distributed energy generated close to load (such as rooftop solar) can also defer investments in traditional delivery system infrastructure and potentially defer the need for additional generation.

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 8-169 as well as consideration of the substation utilization, avoidance of adverse impacts to reliability or operating characteristics, and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

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

Figure 8-170: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement, such as pole or meter replacements, are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs. An example is the cable remediation program which prioritizes based on risks such as number of past failures, number of customers impacted and system configuration that prevents timely restoration.

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

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

PSE recently expanded the capabilities of iDOT to help us evaluate and compare the relative costs and benefits of wire, non-traditional and hybrid alternatives for the Bainbridge, Seabeck, Lynden and Kitsap pilot projects. New non-traditional benefits mapped to existing iDOT categories include generation capacity deferral entered as a cost reduction. Future iDOT enhancements could incorporate benefits such as battery-produced generation capacity deferral and extended asset life, etc., more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100% clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. As non-wire analysis is pursued, it essentially helps to find the most ideal location for distributed

energy resources that are identified through the IRP recommended portfolio, adding value to what has already been captured in that process. Finally, PSE's delivery system planning process will also mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-Wire Alternative Analysis

PSE's planning process has incorporated non-wire alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-wire alternative analysis is a screening process that breaks down of the problem to understand what different pieces may be provided by a distributed energy resource, evaluates the technical distributed energy resource potential, performs an economic analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional wired solution, a full non-wire solution, and potential hybrids across the problem components.

All types of distributed energy resources are considered. With the problem deconstructed to better understand the timing and costs specific portions of the need, a basis analysis tool helps to identify typical distributed energy resources that could solve the problem and whether more detailed analysis is warranted. Leveraging the structure and conservation potential process and tools of the IRP, the analysis may then map distributed energy resource potential to zip codes and estimate hourly load shapes based on specific customer loads to understand the potential further. The analysis may result in a heuristic-based DER potential and cost analysis graphic to help understand what is possible. Understanding the length of investment benefit or lifecycle is important as well such as lifespan of a battery or even demand response programs as home ownership transitions the benefit may change from initial results. The next step of economic analysis determines the costs of alternatives, using traditional cost estimating tools for traditional alternatives, and leveraging IRP cost assumptions and consultant's expertise to understand current and future costs based on developing maturity. This allows for testing optimistic, high benefit value low cost, and pessimistic, low benefit value high cost, considerations through the process. As discussed previously, iDOT can then be used to help evaluate alternatives for benefit to cost and further consider benefits not traditionally quantified. The result of the process is a recommended solution that meets the technical and non-technical solution criteria that then is documented in the solution assessment and the project moves to the project planning phase.

PSE embarked on non-wire analysis in 2018, committing to perform this analysis in four different areas of the system to learn and develop the process. PSE engaged the broad expertise of Navigant and Quanta Technologies to perform and develop its non-wire process and analysis. Non-wire analysis was completed for Bainbridge Island which had a capacity, reliability, aging infrastructure, and operational flexibility need, the entire Kitsap County which had a capacity, aging infrastructure and operational flexibility need, Seabeck which had a smaller circuit capacity and reliability need, and Lynden which had a local capacity, reliability, aging infrastructure, and operational flexibility need. The analysis on these four areas spanned almost 2 years which highlights the complexity of this type of analysis. More detail can be found for each of these area needs in Appendix M.

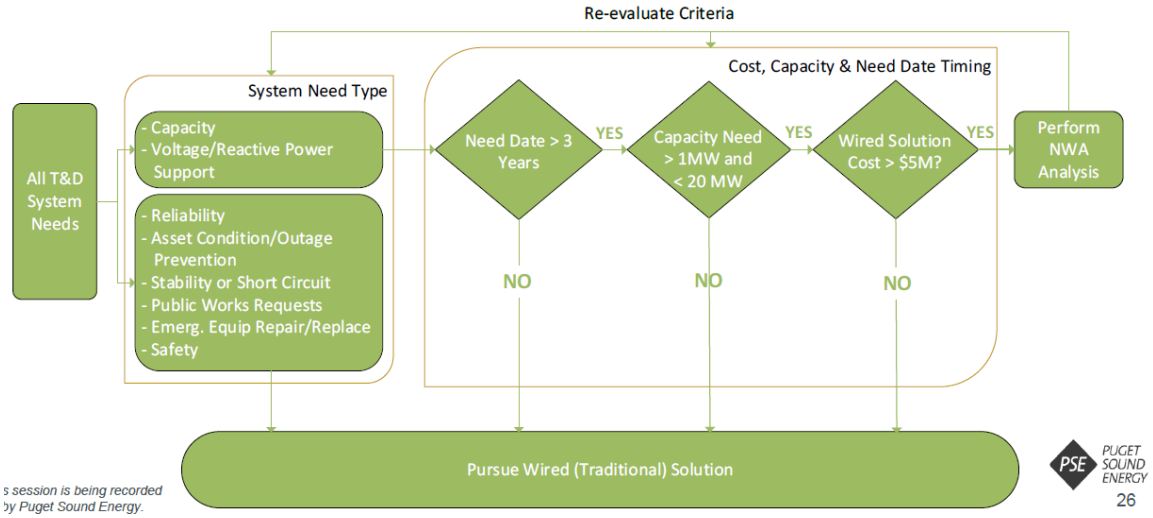
As a result of this analysis, there are some lessons learned relative to results and where this lengthy complex analysis is most valued. Key findings thus far are that:

- Capacity needs can be effectively met using non-wire alternatives when right sized, maximizing behavior based solutions first. Distributed energy resources that are too large begin to exceed traditional alternatives due to higher cost and long duration of need. Recharging requirements of batteries become as great of a challenge as discharging in some cases.
- Reliability needs are more challenged using non-wire alternatives depending on the length of reliability concern and location of need. Resilience needs, while not discussed much, may be ideal for future distributed energy resource supporting microgrids and locations where critical facilities exist for resilience such as train stations, refueling locations, life support facilities, and commerce.
- Aging infrastructure needs are challenged using non-wire alternatives as they are generally specific locational needs and equipment that if removed cause a wide duration and impact as a result of the connectivity of the grid.
- Non-wires analysis is a time intensive process requiring skilled resources and as a result costs more. Deploying this analysis where the project initiation cost brings value is important to consider in the scheme of the total project costs.
- Non-wire solutions may take time to implement depending on the type of distributed energy resource, PSE's experience, and grid readiness. Solutions such as demand response or behavior based solutions will take time to implement and build reliable confidence to defer traditional solutions. As PSE completes AMI and ADMS implementation and additional grid modernization investments, cost effectiveness of non-wire solutions will increase.

PSE has drafted an initial non-wires screening as a result, Figure 8-171, and through the 2021 IRP began seeking feedback from IRP stakeholders. PSE has performed additional analysis

since the initial four areas were identified and these continued studies along with operational experience from previous installations such as PSE's battery in Glacier, Washington as well as on-going pilots will be used to inform this study screening process. This process will be adjusted as technology mature and cost decrease as well.

Figure 8-171: Non-wire Alternative Screening Criteria



Project Planning and Implementation Phase

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

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

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



9 Natural Gas Analysis

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

9 Natural Gas Analysis

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1. RESOURCE NEED AND DISCUSSION TOPICS

Resource Need

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

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

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

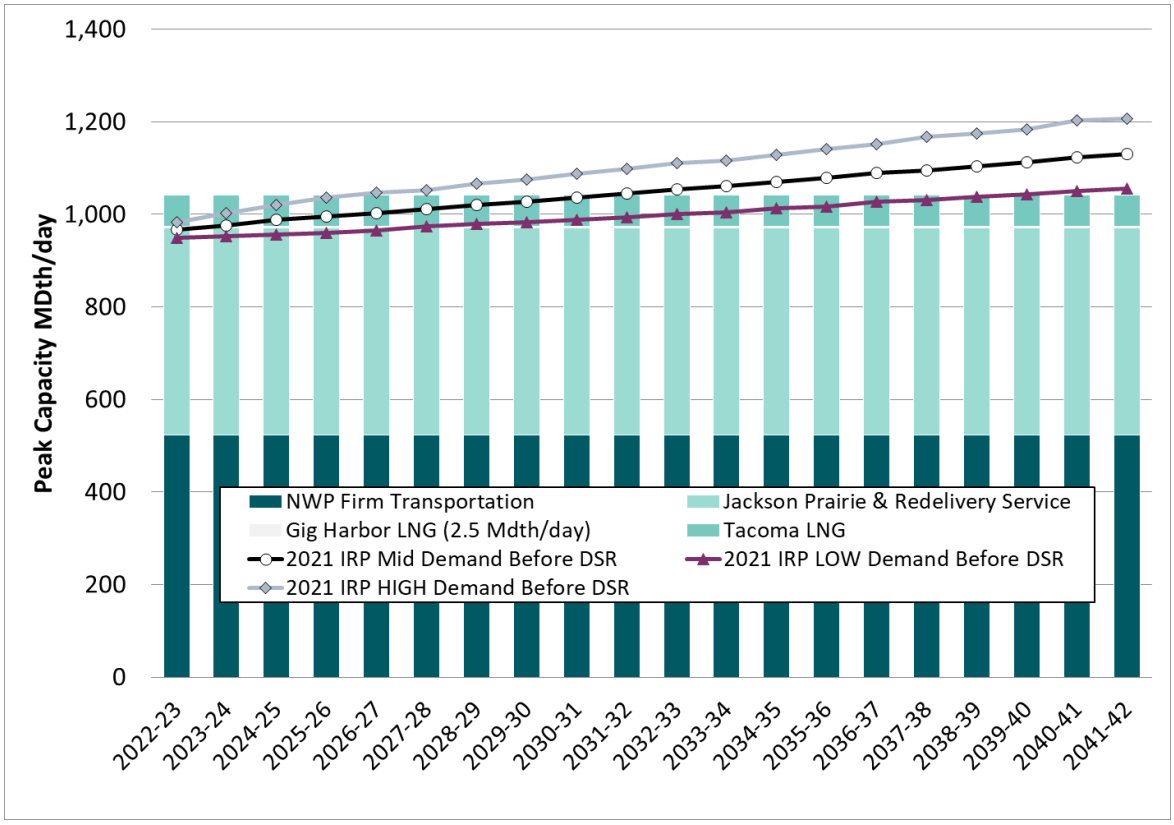
- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need throughout the study period.
- In the Mid Demand Forecast, the first resource need occurs in the winter of 2031-32.
- In the High Demand Forecast, the first resource need occurs immediately.

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

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

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

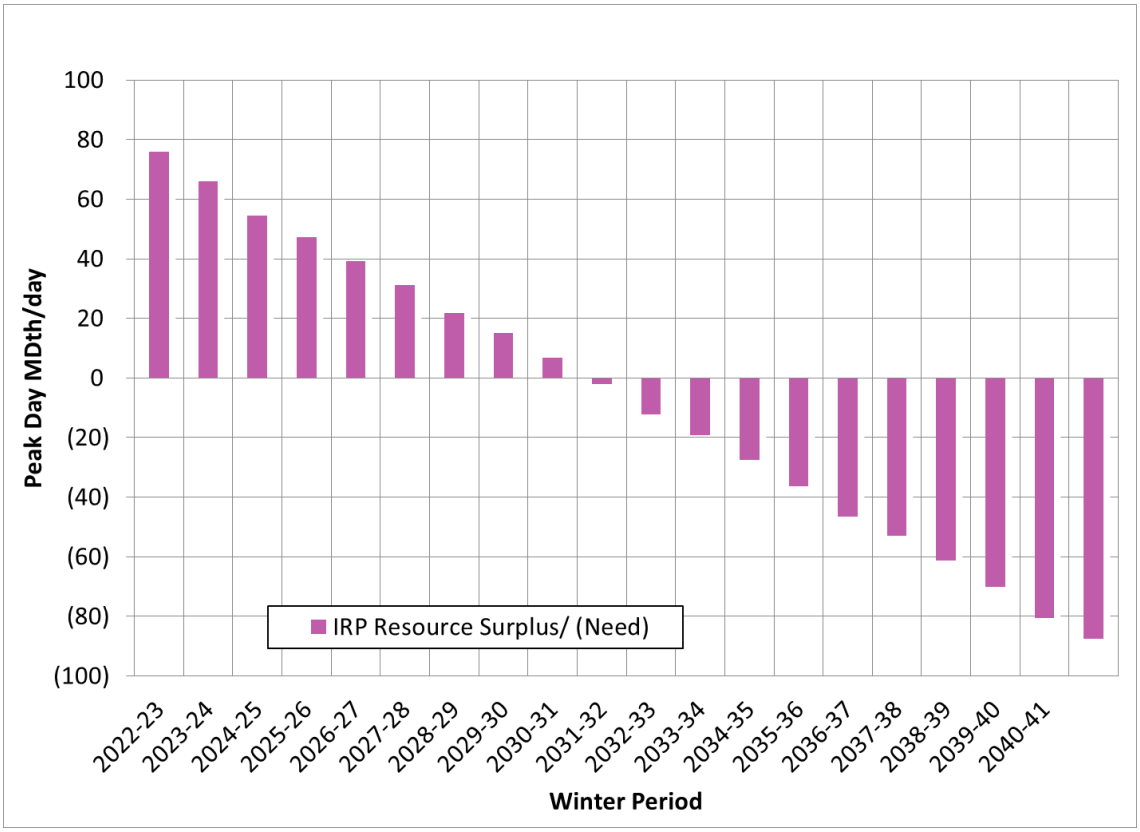
Figure 9-1: Natural Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (meeting need on the coldest day of the year)



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

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

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



Discussion Topics

Infrastructure Reliability

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

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

Two incidents illustrate how these strategies work in practice.

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

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

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

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

Supply Adequacy

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

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

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

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

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

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

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

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

2. ANALYTIC METHODOLOGY

Analysis of the natural gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of natural gas resources in a variety of scenarios. Renewal or term extension of existing resources are among the alternatives considered.

Analysis Tools

PSE uses a gas portfolio model (GPM) to analyze natural gas resources for long-term planning and long-term natural gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them.

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

Deterministic Optimization Analysis

PSE developed three natural gas scenarios for this IRP analysis, Mid, High and Low, as shown in Figure 9-3.[7] Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

Figure 9-3: 2021 IRP Natural Gas Analysis Scenarios

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

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

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

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

Figure 9-4 2021 IRP Natural Gas Portfolio Sensitivities

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

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

Natural Gas Peak Day Planning Standard

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

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

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

Figure 9-5: PSE Planning Standard Implied Temperature Criteria

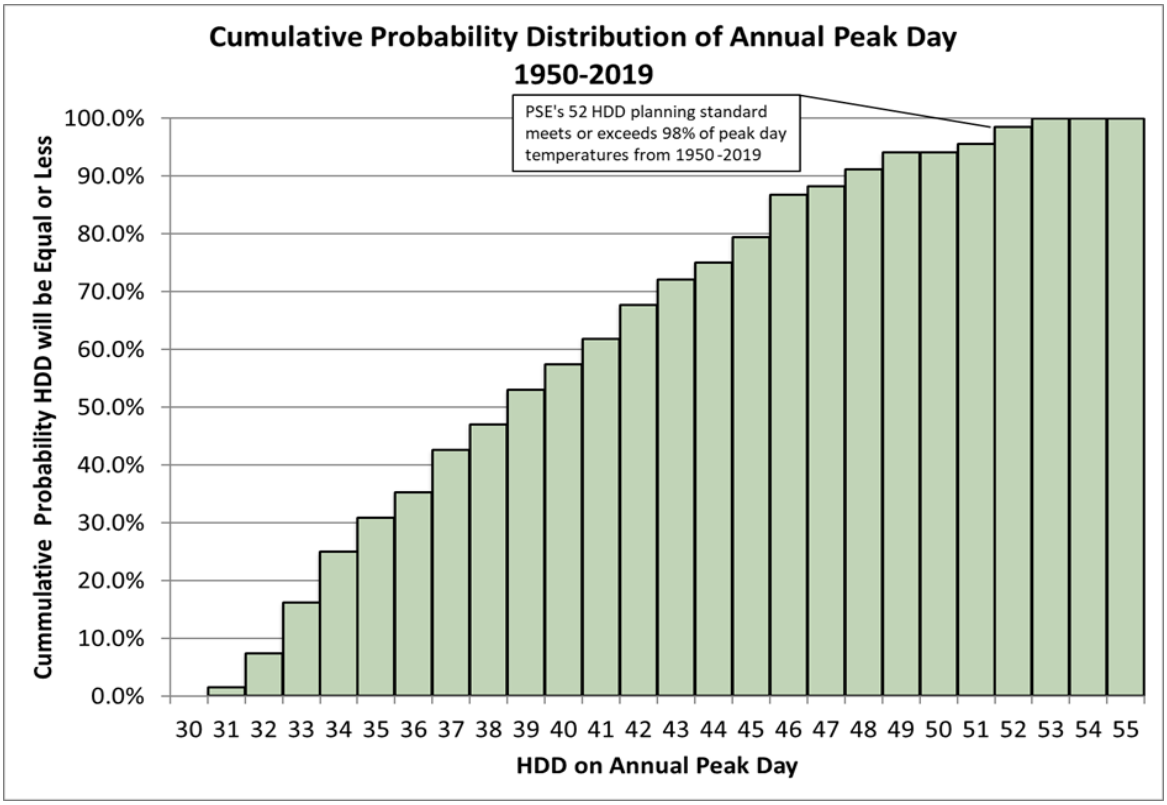


Figure 9-6: Pacific Northwest Natural Gas Utility Planning Standards

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

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

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

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

3. EXISTING RESOURCES

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

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver natural gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

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

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

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

Upstream Pipeline Capacity

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

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

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

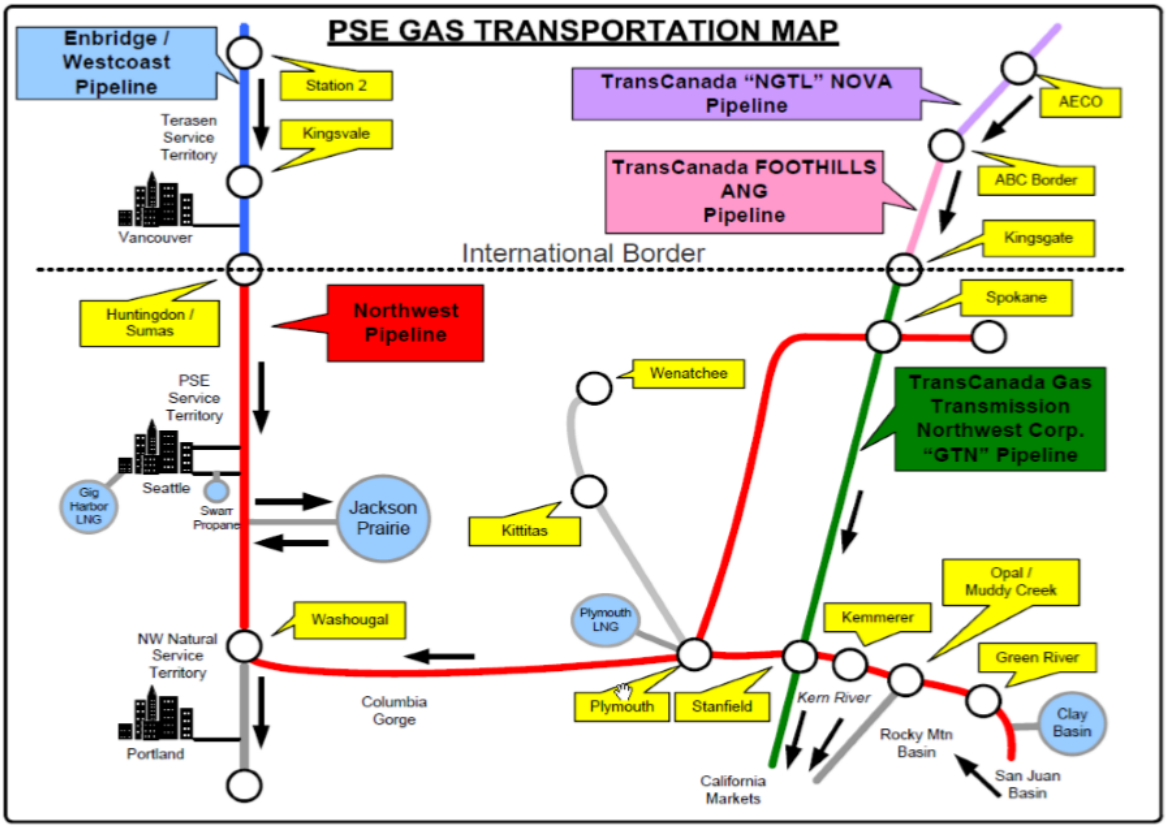


Figure 9-8: Natural Gas Sales - Firm Pipeline Capacity (Dth/day) as of 11/01/2020

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

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

NOTES
1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.
3. Converted to approximate Dth per day from contract stated in gigajoules per day.
4. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.
5. Capacity can alternatively be used to deliver additional volumes to Spokane.
6. Converted to approximate Dth per day from contract stated in cubic meters per day. Westcoast has adjusted the heat content factor upward to reflect the higher Btu gas now normal on its system. The effect is to allow customers to transport more Btu in the same contractual capacity.
7. The Westcoast contracts contain a right of first refusal upon expiration.
8. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.

Transportation Types

TF-1

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

Storage Redelivery Service

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

Primary Firm, Alternate Firm and Interruptible Capacity

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

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

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

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

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

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

Existing Storage Resources

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

- Ready access to an immediate and controllable source of firm natural gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store natural gas during the lower-demand summer season, generally at lower prices, for use during the high-demand winter season.
- Combining storage capacity with firm storage redelivery service transportation allows PSE to contract for less of the more expensive year-round pipeline capacity.
- PSE also uses storage to balance city gate gas receipts from natural gas marketers with the actual loads of our natural gas transportation customers.

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

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

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

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

Jackson Prairie Storage

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

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core natural gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores natural gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service.

PSE uses Clay Basin for certain levels of baseload supply and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Natural gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP TF-1 transportation.

Treatment of Storage Cost

Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for natural gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

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

Figure 9-10: Natural Gas Sales Peaking Resources

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

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

Gig Harbor LNG

Located in the Gig Harbor area of the Kitsap Peninsula, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source, and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows natural gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-Air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's natural gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility's environmental, safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP in Combination #7 – Swarr LP-Air Upgrade, and is assumed to be available on three years' notice as early as the 2023/24 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

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

Existing Natural Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to natural gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing natural gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta. PSE's pipeline capacity on NWP currently provides for 50 percent of our flowing natural gas supplies to be delivered from north of our service territory and the remaining 50 percent from south of our service territory.

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

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

9 Natural Gas Analysis

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

Existing Demand-side Resources

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

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

Energy savings targets and the programs to achieve those targets are established every two years. The 2018-2019 biennial program period concluded at the end of 2019. The current program cycle runs from January 1, 2020 through December 31, 2021 and has a two-year energy savings target of approximately 8 million therms. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group.

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

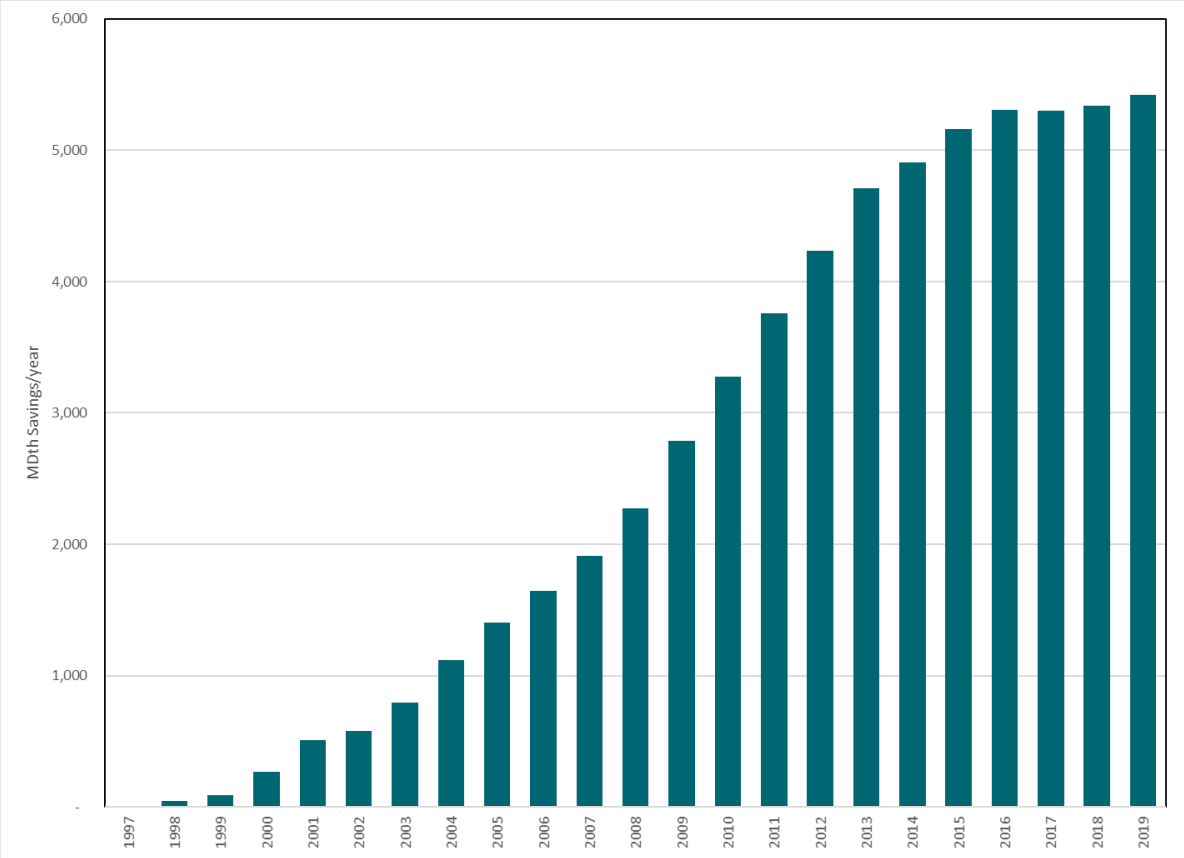
Figure 9-11 summarizes energy savings and costs for 2018 through 2021.

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

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

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

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



4. RESOURCE ALTERNATIVES

The natural gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting natural gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and natural gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analysis purposes. These combinations are discussed below and illustrated in Figure 9-13. Note that demand-side resources is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

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

Combination # 1 & 1a – NWP Additions + Westcoast

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

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

Combination # 2 – FortisBC/Westcoast (KORP)

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

Combination # 3 – Cross Cascades – NWP from AECO

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

Combination # 4 – Mist Storage and Redelivery

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

Combination # 5 – Plymouth LNG with Firm Delivery

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

Combination # 6 – LNG-related Distribution Upgrade

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

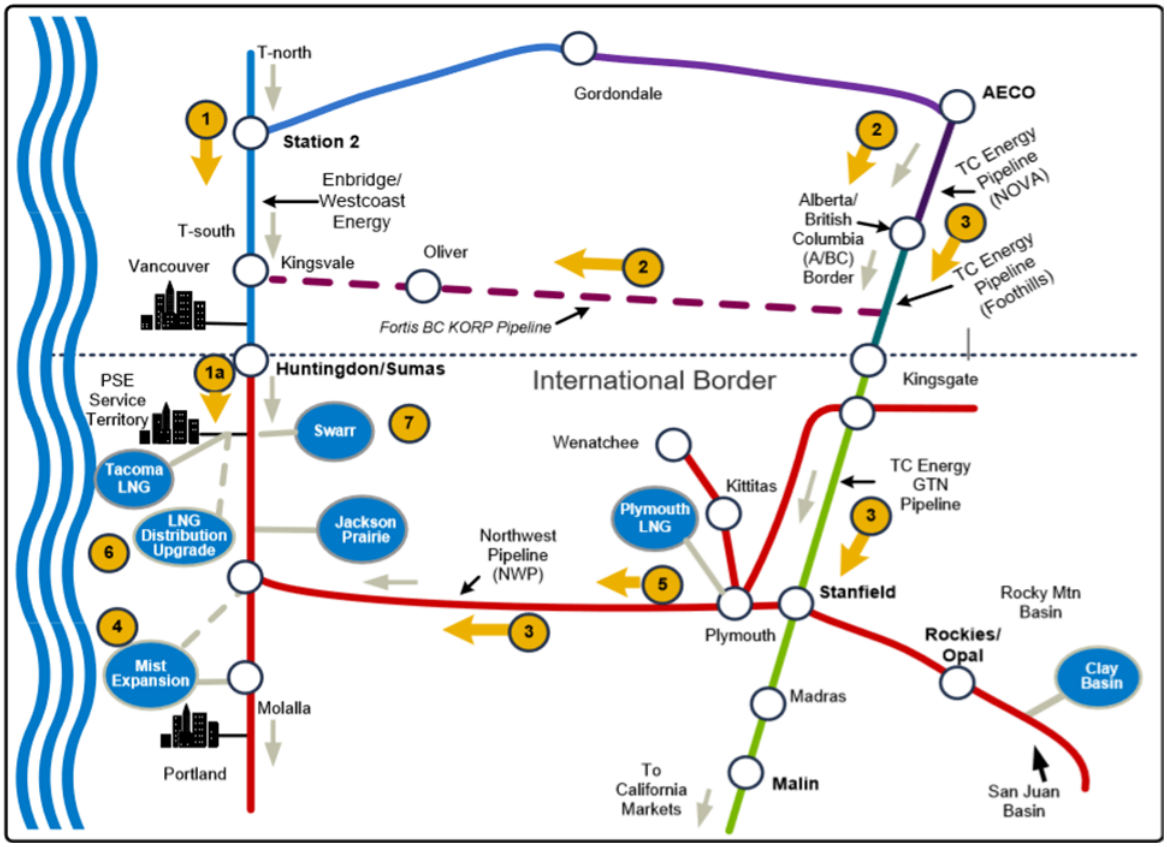
Combination # 7 – Swarr LP-Air Upgrade

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

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

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

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



Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

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

Figure 9-14: Direct-connect Pipeline Alternatives Analyzed

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

Upstream Pipeline Capacity Alternatives

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

Figure 9-15: Upstream Pipeline Alternatives Analyzed

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

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

Storage and Peaking Capacity Alternatives

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

Mist Expansion

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

LNG-related Distribution System Upgrade

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

Swarr

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

Figure 9-16: Natural Gas Storage Alternatives Analyzed

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

Natural Gas Supply Alternatives

Conventional Natural Gas

As described earlier, natural gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate natural gas supplies will be available to support pipeline expansion from northern British Columbia via Westcoast or TC-NGTL,TC-Foothills and TC-GTN or from the Rockies basin via NWP.

Renewable Natural Gas (RNG)

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

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

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

The aforementioned contract acquisition of landfill RNG will, within a few years, provide RNG equal to approximately 2 percent of PSE's current supply portfolio and as much as a 1.5 percent reduction in the carbon footprint of PSE's natural gas system, annually. PSE is planning significant further investments in cost-effective RNG, and PSE is confident that it can acquire sufficient RNG volumes to meet the needs of its future voluntary RNG program participants and even exceed the 5 percent cost limitation related to the RNG incorporated into the supply

portfolio. In order to meet the expectations in the WUTC RNG Policy Statement, PSE will utilize staggered RNG supply contracts and project development timelines, resales in compliance markets and other techniques to manage RNG costs while maximizing the availability of RNG in its portfolio and achieving meaningful carbon reductions.

Demand-side Resource Alternatives

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

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

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

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

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

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

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

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

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

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

In the final step, the natural gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 9-18 illustrates the methodology described above.

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

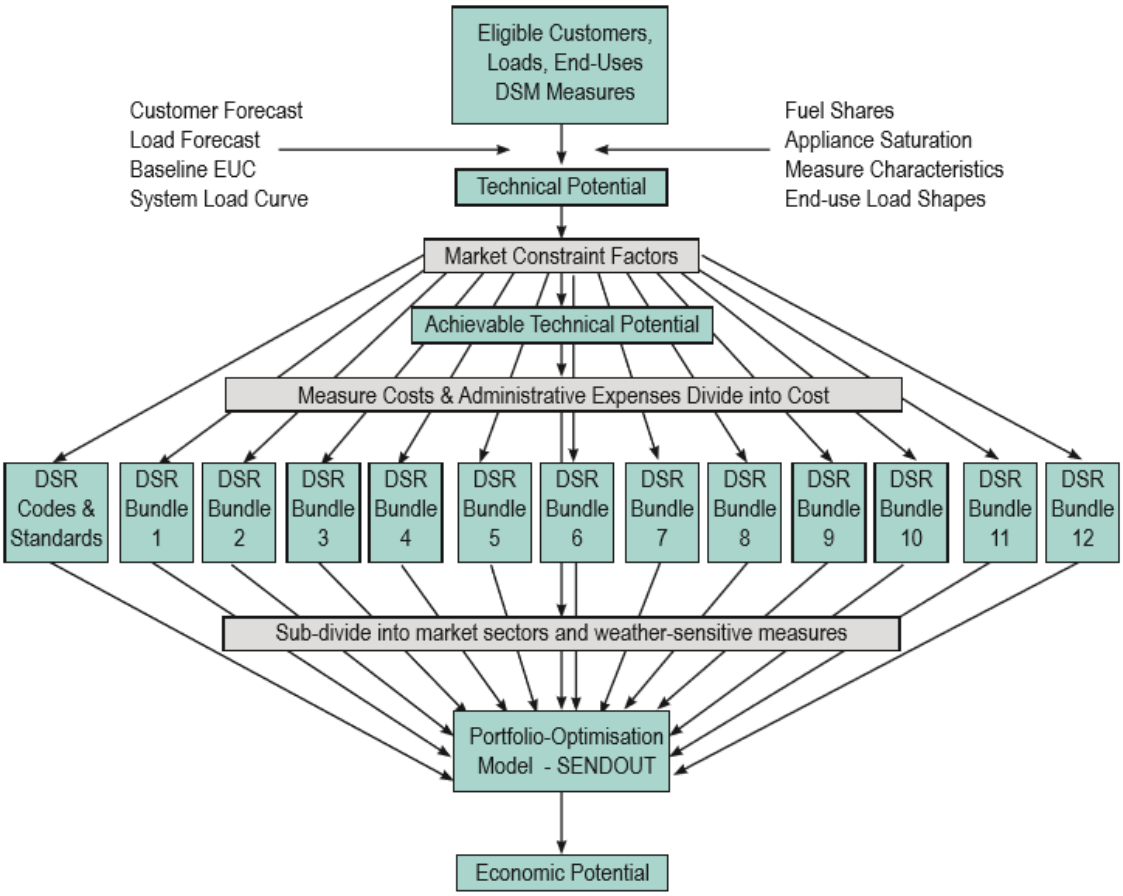


Figure 9-19 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side natural gas resource for a particular scenario.

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

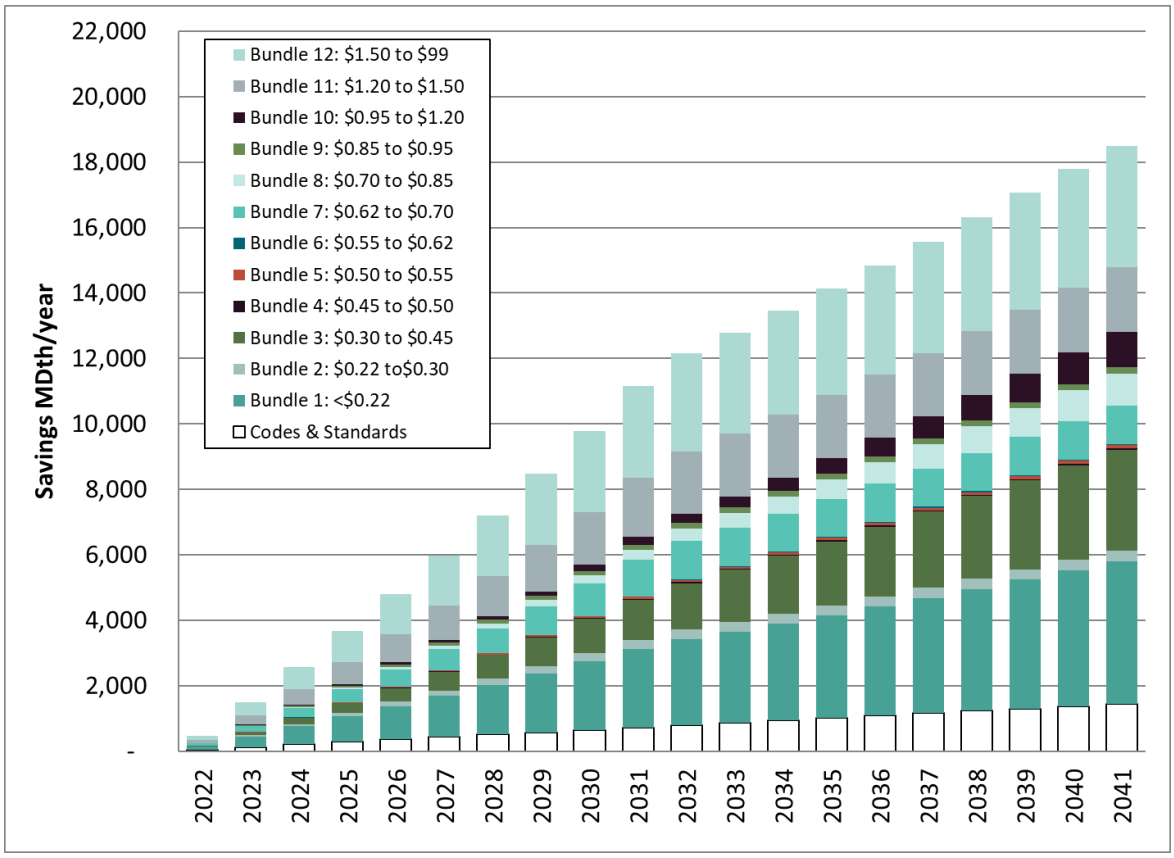
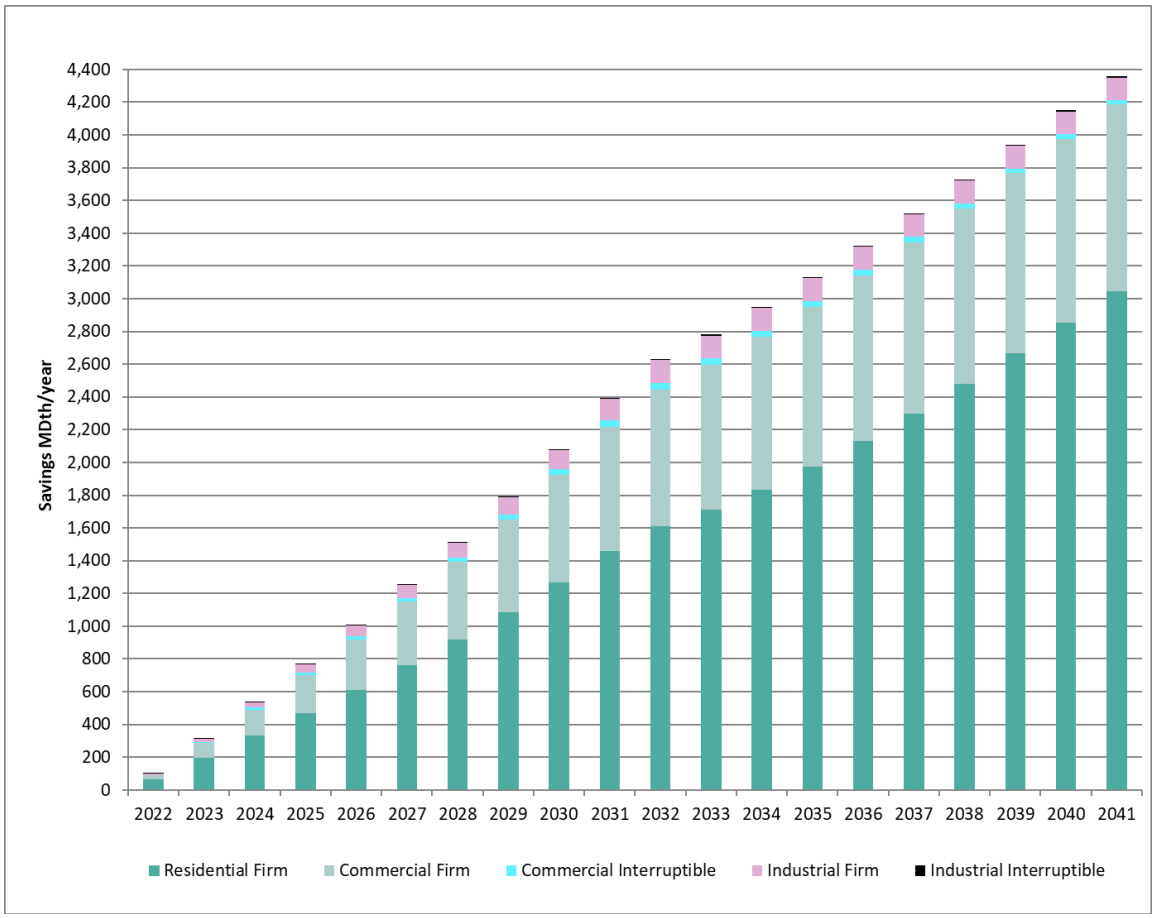


Figure 9-20 shows DSR savings subdivided by customer class. This input format is used in the GPM for all bundles in all the IRP scenarios.

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



5. NATURAL GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

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

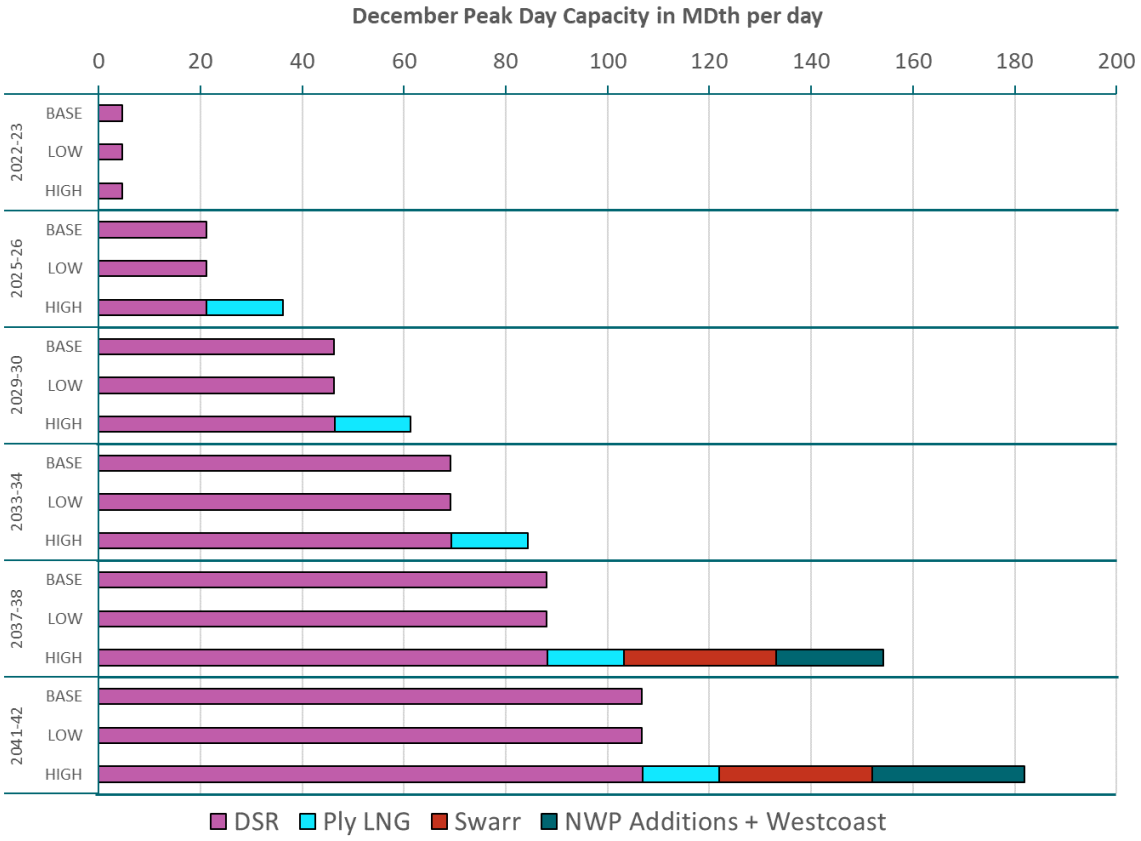
8. **Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in only the High scenario.** The GPM indicates this pipeline capacity is cost effective starting in 2034/35.
9. **Neither the Cross Cascades TC new pipeline or the Fortis BC KORP project are selected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

Natural Gas Sales Portfolio Resource Additions Forecast

Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, natural gas prices and CO_2 price assumptions. Demand-side resources are influenced directly by natural gas and CO_2 price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by the new supply curve and load growth assumptions. Also, the timing of pipeline additions was limited to five-year increments, because of the size that these projects require to achieve economies of scale.

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

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



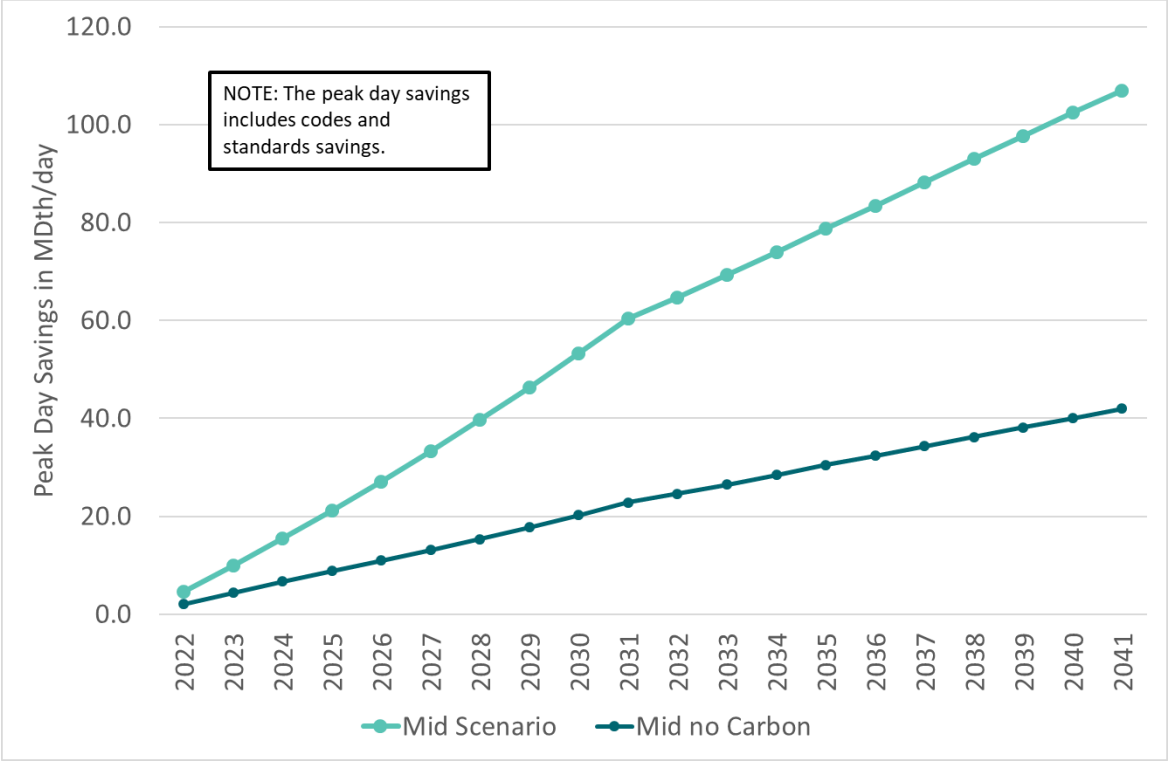
Demand-side Resource Additions

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

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

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

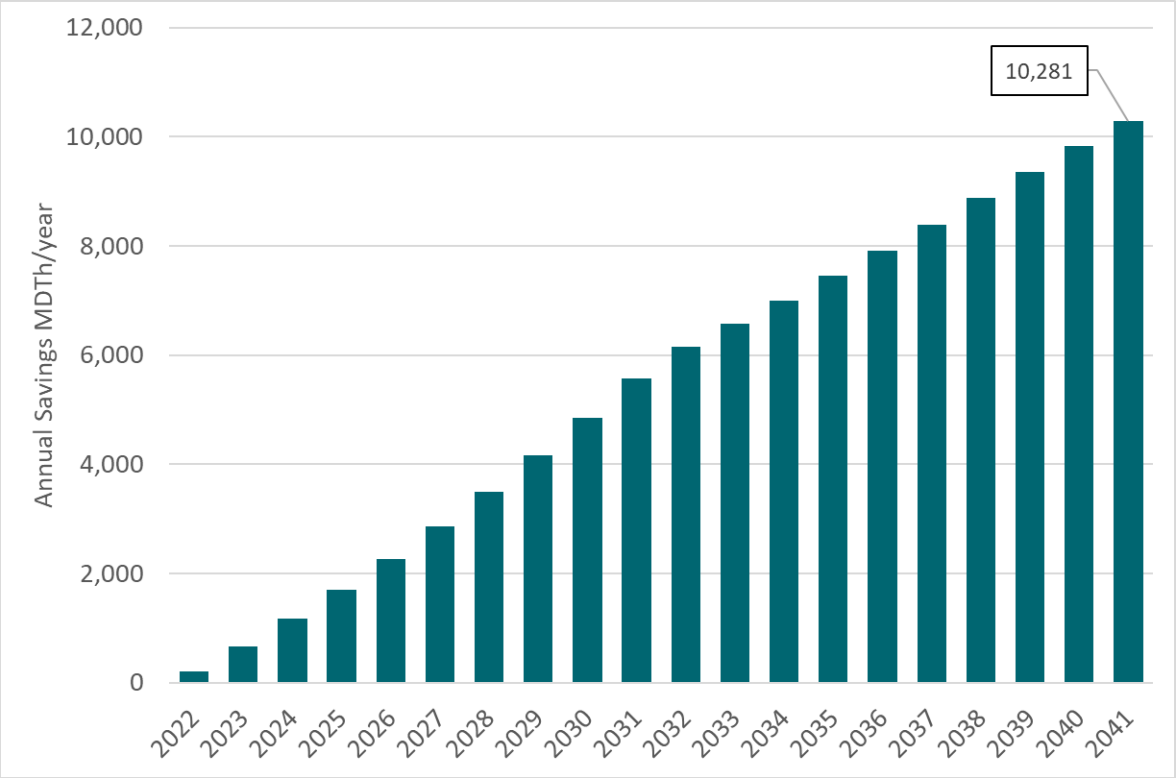
Figure 9-22: Sensitivity of Carbon to Cost-effective Natural Gas Energy Efficiency Savings in the Mid Scenario



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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

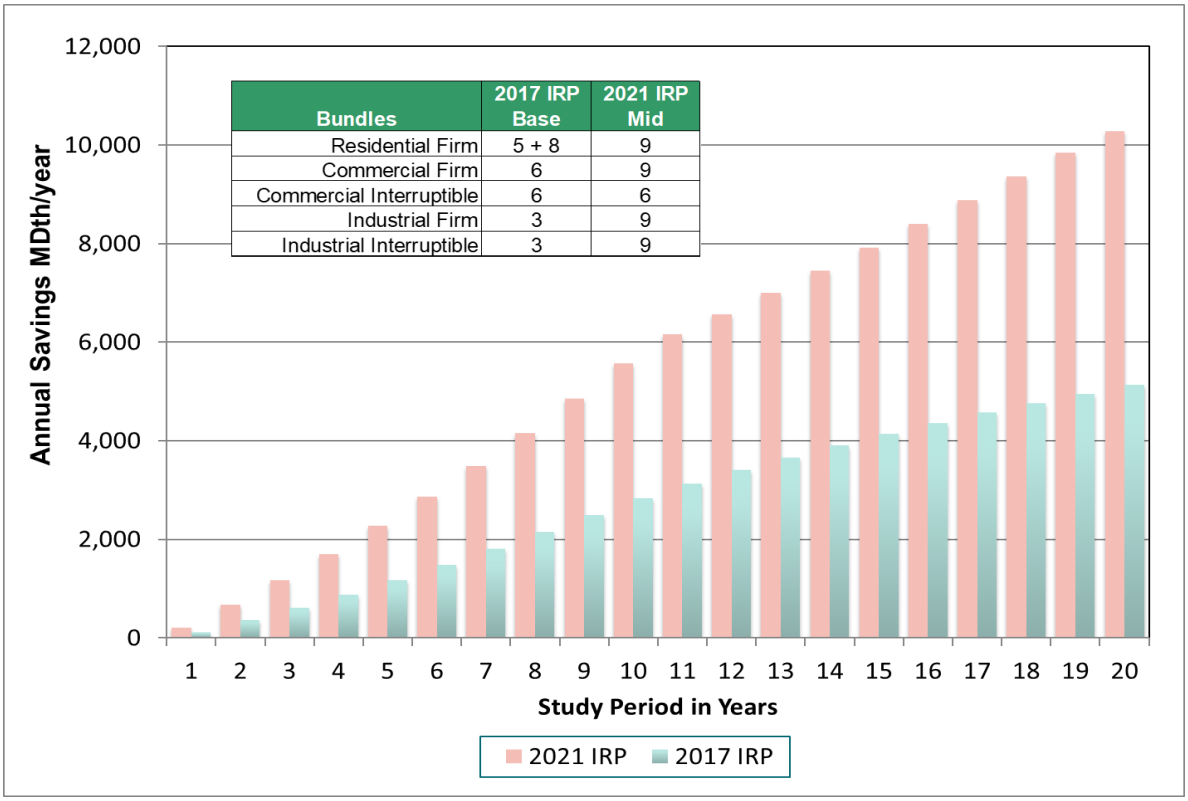


Figure 9-27 compares PSE's energy efficiency accomplishments, current targets and the new range of natural gas efficiency potentials determined by the 2021 IRP. In the short term, the 2021 IRP indicates an economic potential savings of 1,192 MDth for the 2022-2023 period for all three scenarios.[11]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

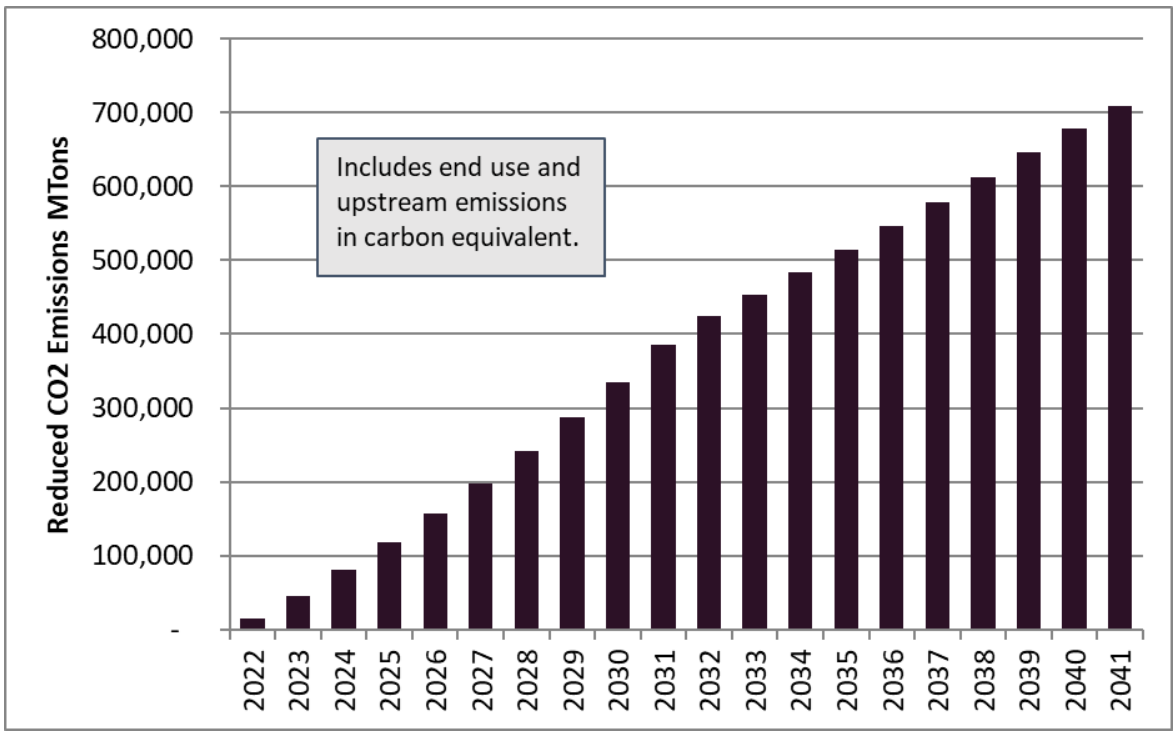
Figure 9-27: Short-term Comparison of Natural Gas Energy Efficiency in MDth

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

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

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

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



Peaking Resource Additions

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

Pipeline Additions

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

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

Observation

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

Complete Picture: Natural Gas Sales Mid Scenario

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

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

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

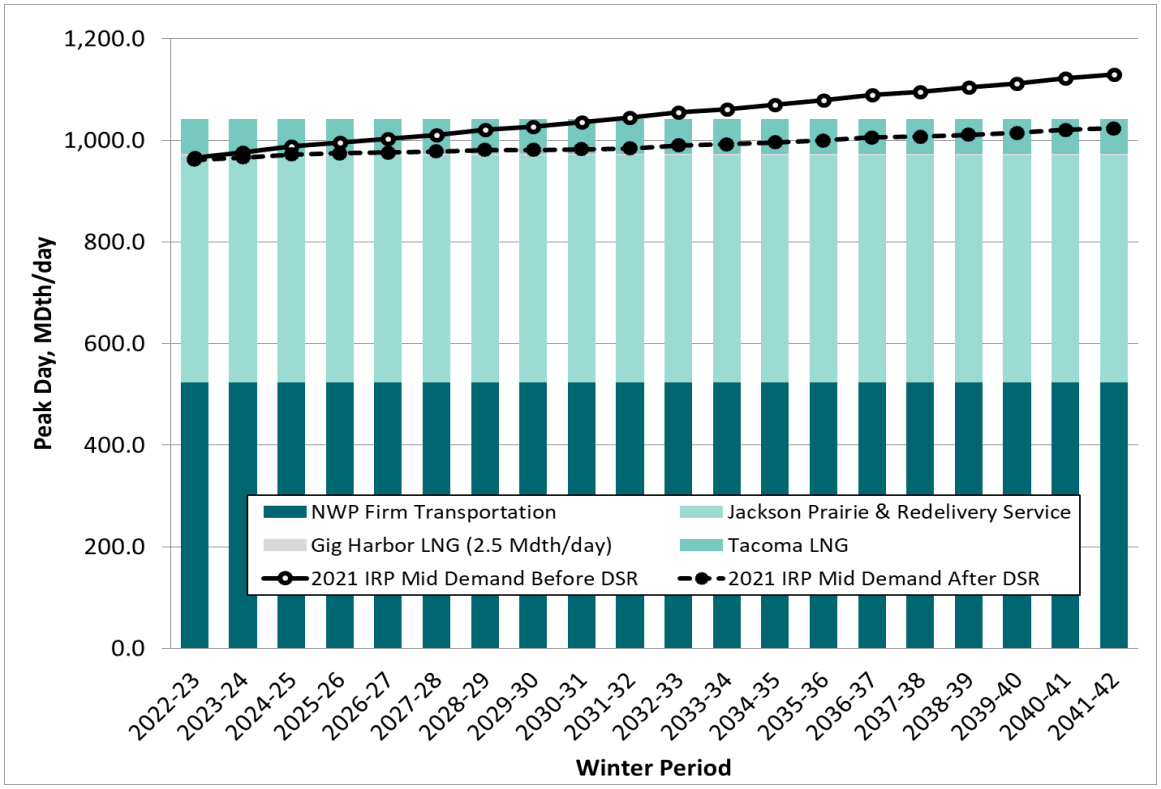


Figure 9-30: Natural Gas Sales Mid Scenario Resource Portfolio (Table)

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

Average Annual Portfolio Cost Comparisons

Figure 9-31 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the Tacoma LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

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

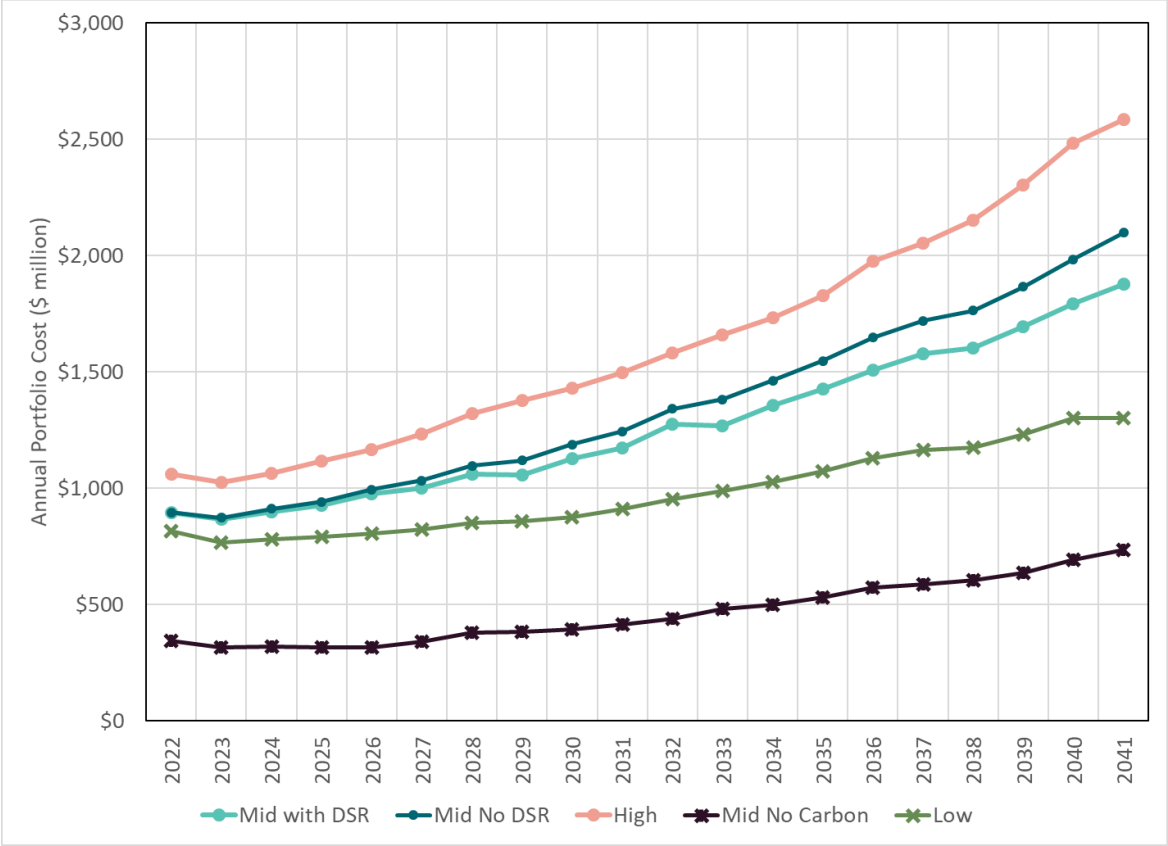


Figure 9-31 shows that average optimized portfolio costs are heavily impacted by natural gas prices and CO_2 cost assumptions included in each scenario.

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

Sensitivity Analyses

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

A. AR5 Upstream Emissions

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

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

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

Figure 9-32: Upstream Emissions for AR4 and AR5

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

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

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

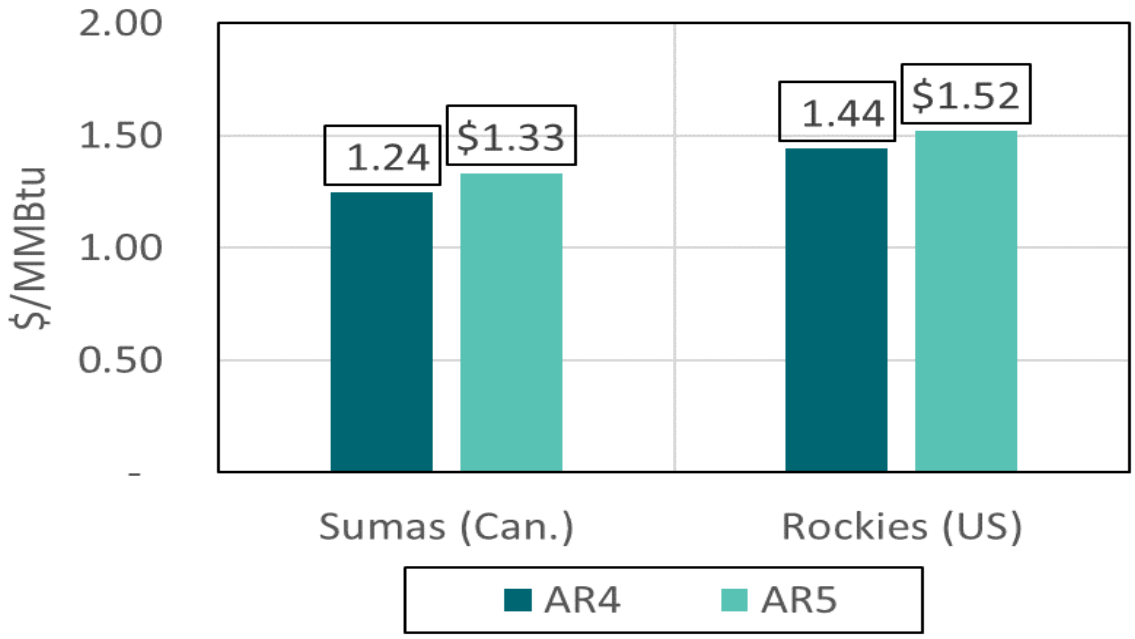


Figure 9-34: 20-year NPV for AR5 Portfolio vs. AR4 Portfolio

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

B. 6-year Conservation Ramp Rate

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

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

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

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

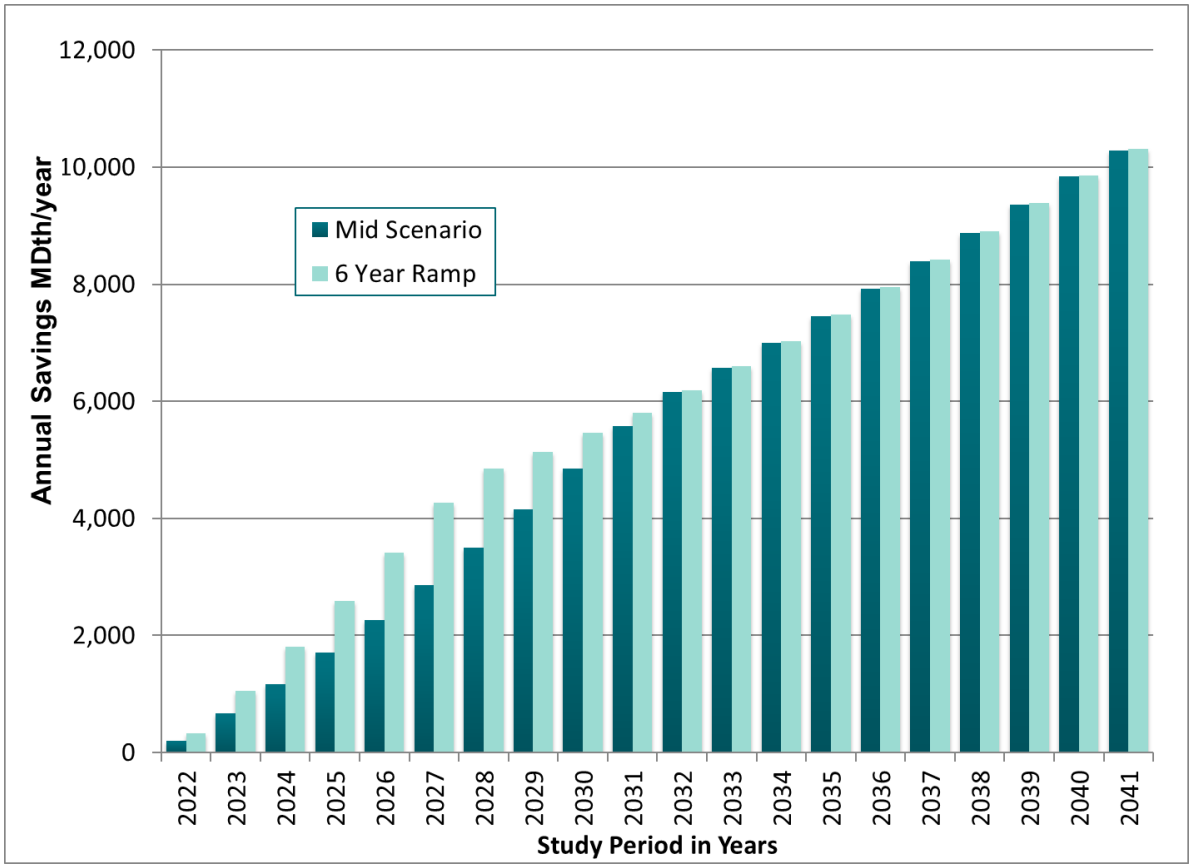


Figure 9-36: NPV for 6-year Ramp Rate vs. 10-year Ramp Rate

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

C. Social Discount Rate for DSR

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

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

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

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

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

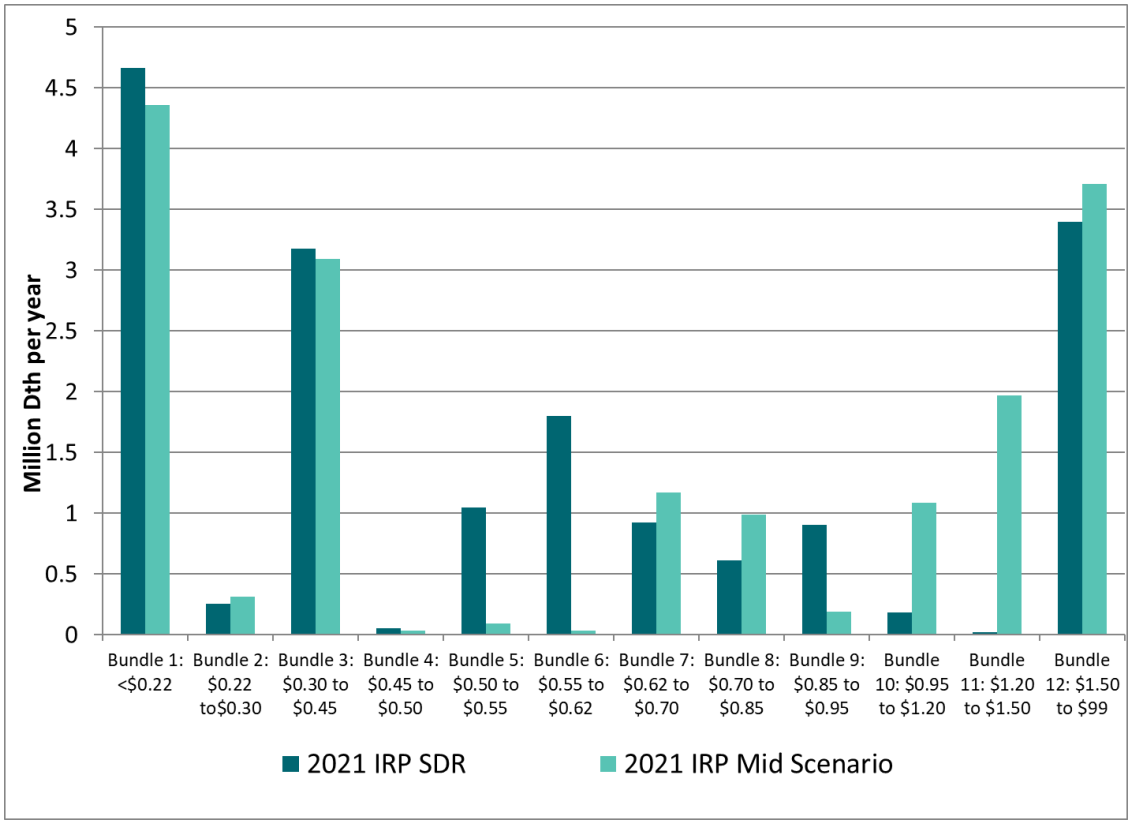


Figure 9-38 Cost-effective Level of Natural Gas DSR, 6.8% Mid Scenario Discount Rate vs. 2.5% Social Discount Rate

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

D. Fuel Switching, Gas to Electric

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

Figure 9-39: Gas to Electric Fuel Switching Assumptions

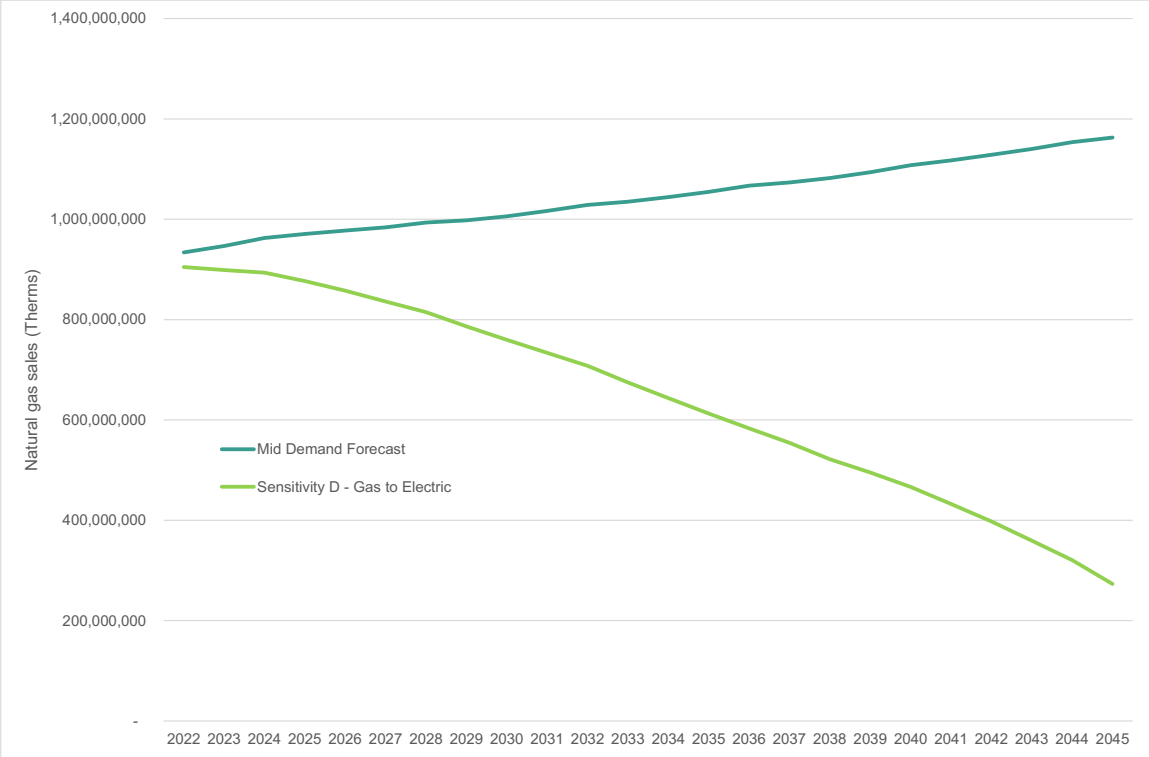
	Assumption
PSE Customer Base	Energy demand is reduced based on the hybrid heat pumps included in the mid demand forecast for the natural gas portfolio.
Hybrid Heat Pumps	Hybrid heat pumps rolled out for existing and new construction. By 2030, 50% of the total addressable achievable potential will be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

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

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

total 2019 natural gas sales, natural gas sales decrease by 21 percent by 2030 and 74 percent by 2045.

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

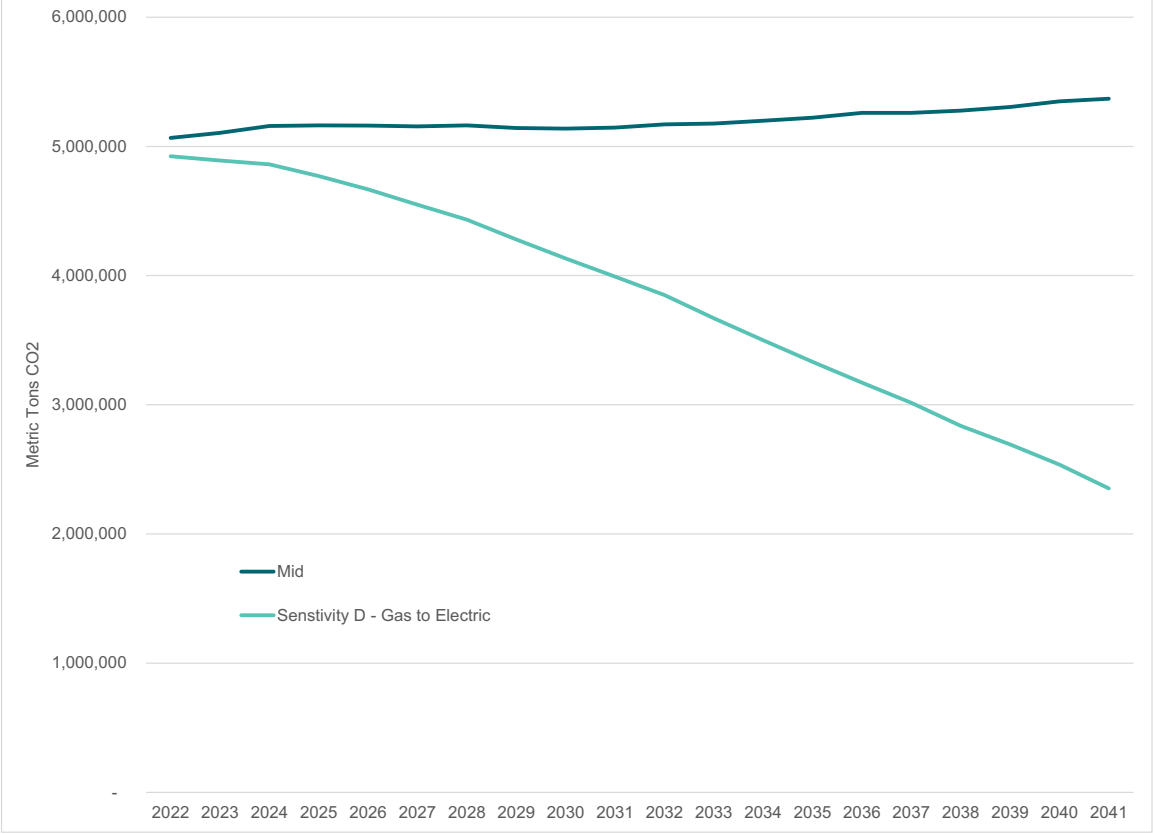


For the residential and commercial sectors, PSE calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. Then each natural gas unit was matched to an equivalent electric equipment; annual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

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

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

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



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

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

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

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

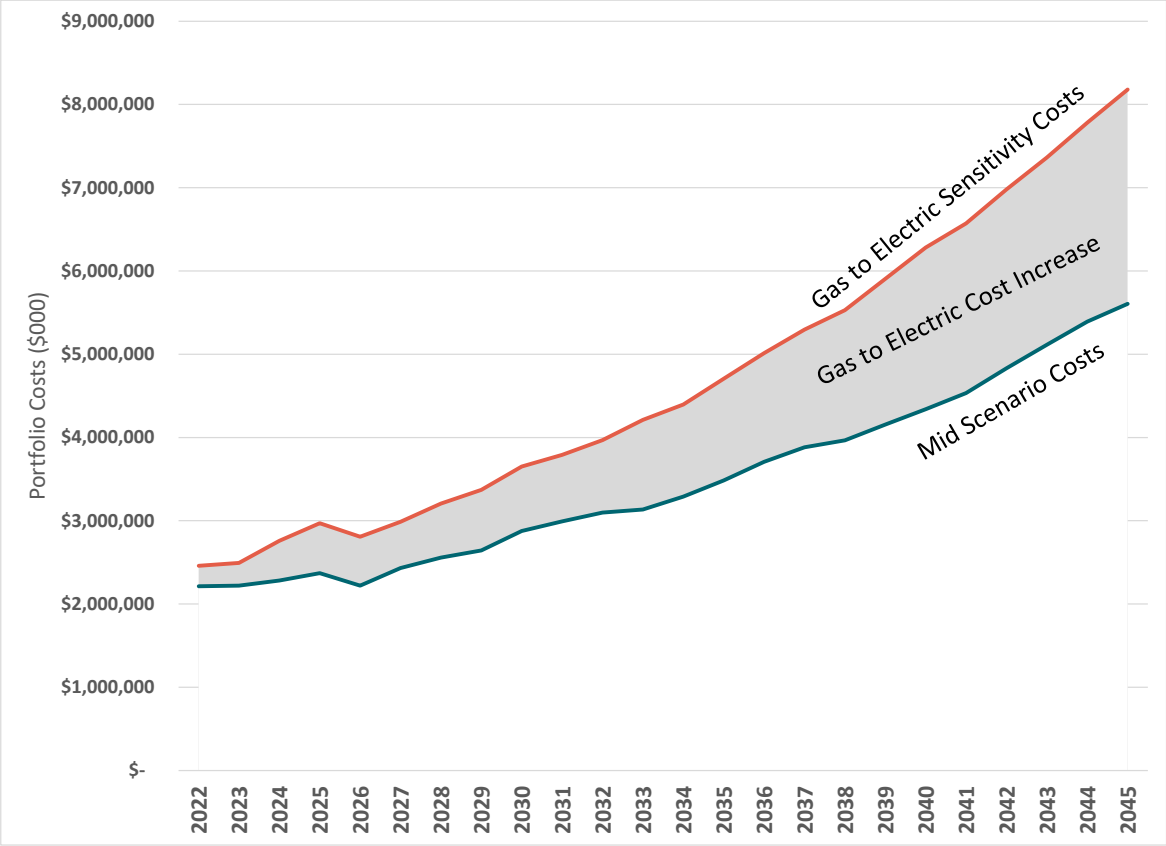
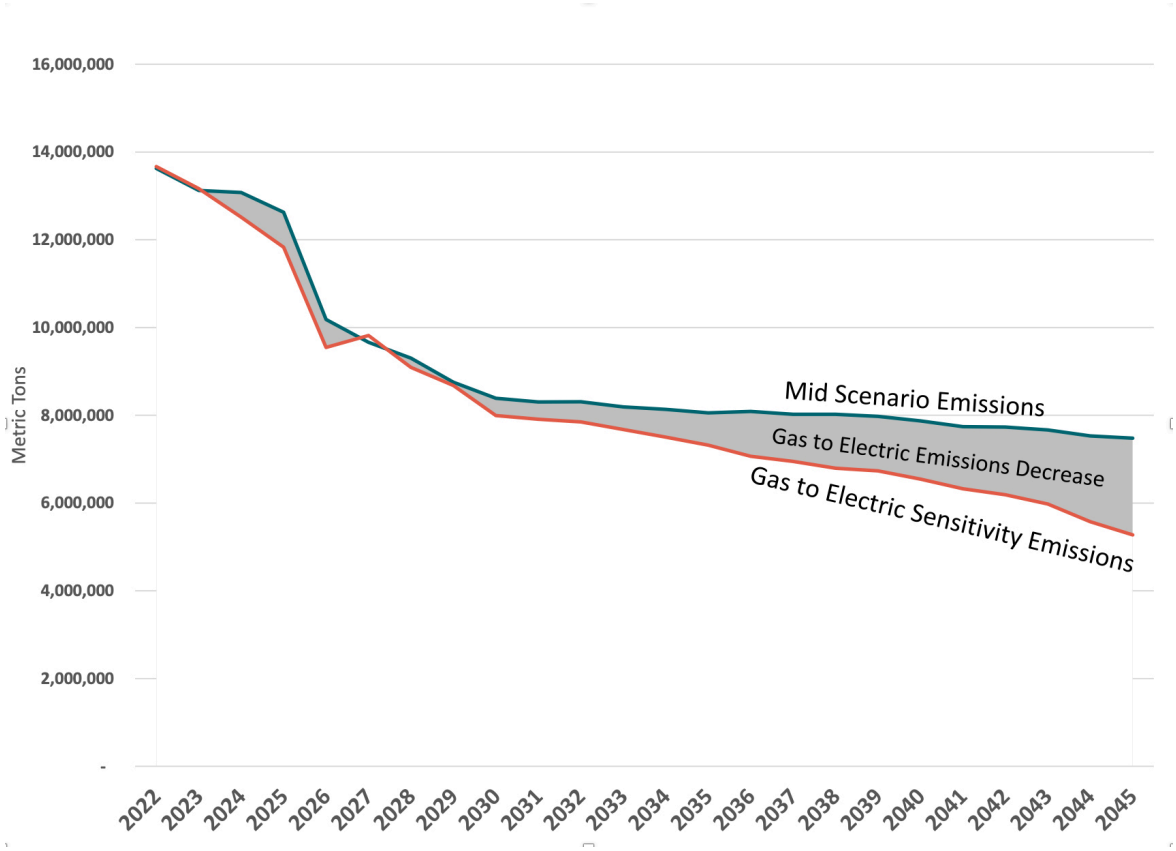


Figure 9-44: Direct and Indirect Portfolio Emissions – Mid Scenario and Sensitivity D, (not including alternative compliance for the electric portfolio)



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

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

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

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

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

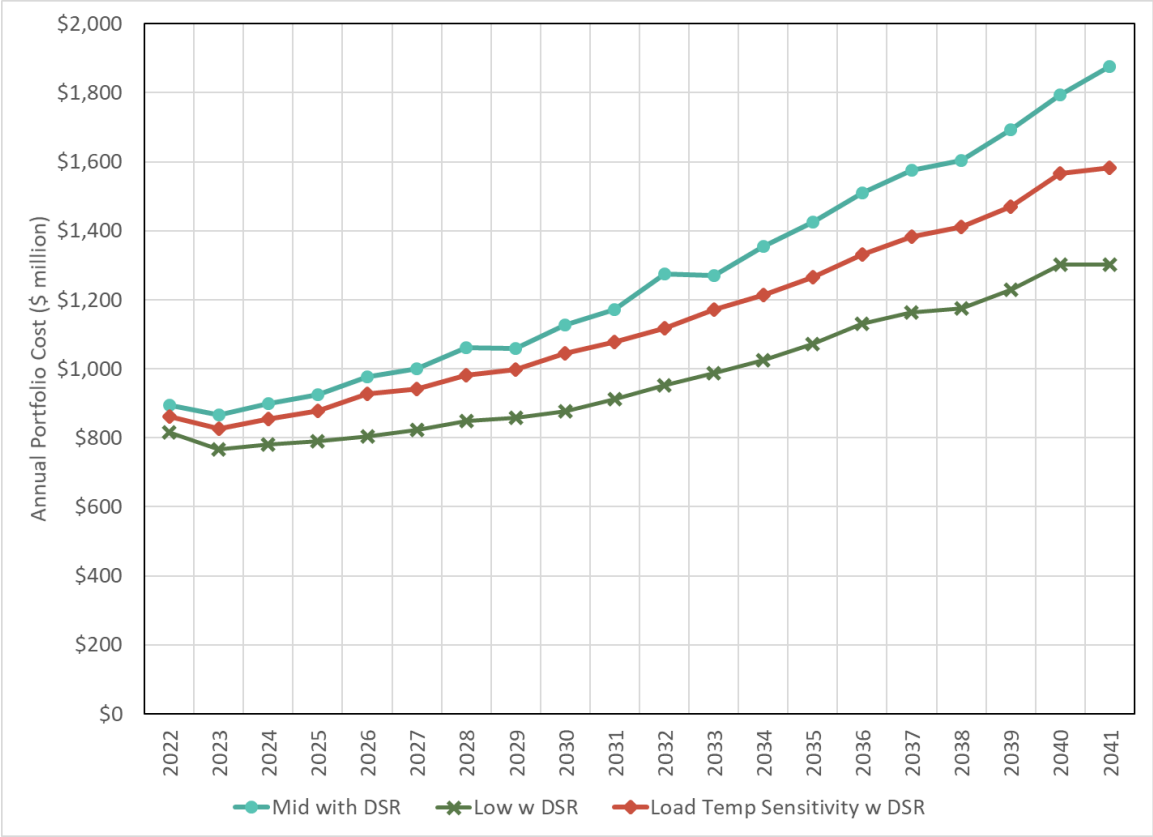
E. Temperature Sensitivity

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

BASELINE ASSUMPTION: The Base Demand Forecast used in the Mid Scenario is based on "normal" weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the past 30 years ending in 2019.
SENSITIVITY > PSE uses temperature data from the Northwest Power and Conservation Council (the "Council"). The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is, therefore, consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE has smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, which is the rate of temperature increase found in the Council's climate model.

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

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



F. No DSR

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

BASELINE ASSUMPTION: New energy efficiency resources are acquired when cost effective and needed.
SENSITIVITY > No new energy efficiency is allowed in the portfolio and all future needs will be met by supply-side resources.

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

Stochastic Analyses

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

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

Development of Input Draws

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

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

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

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

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

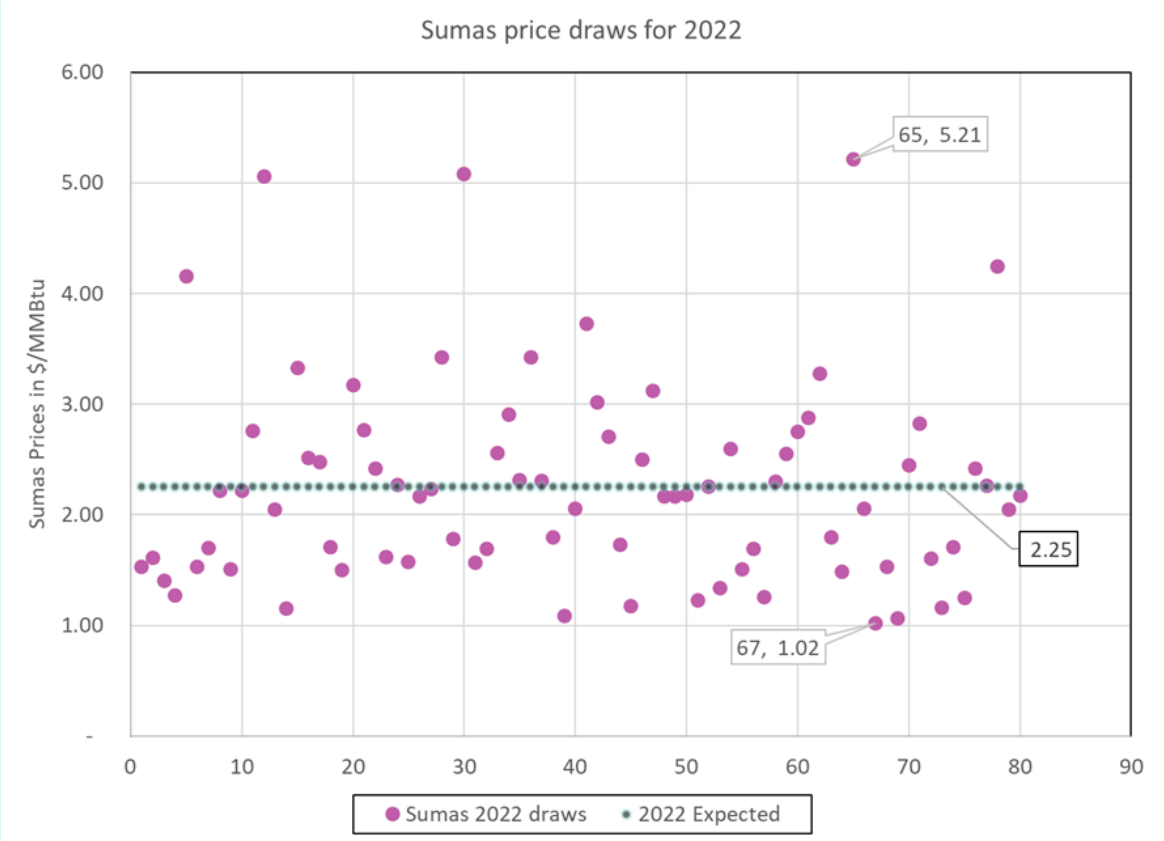
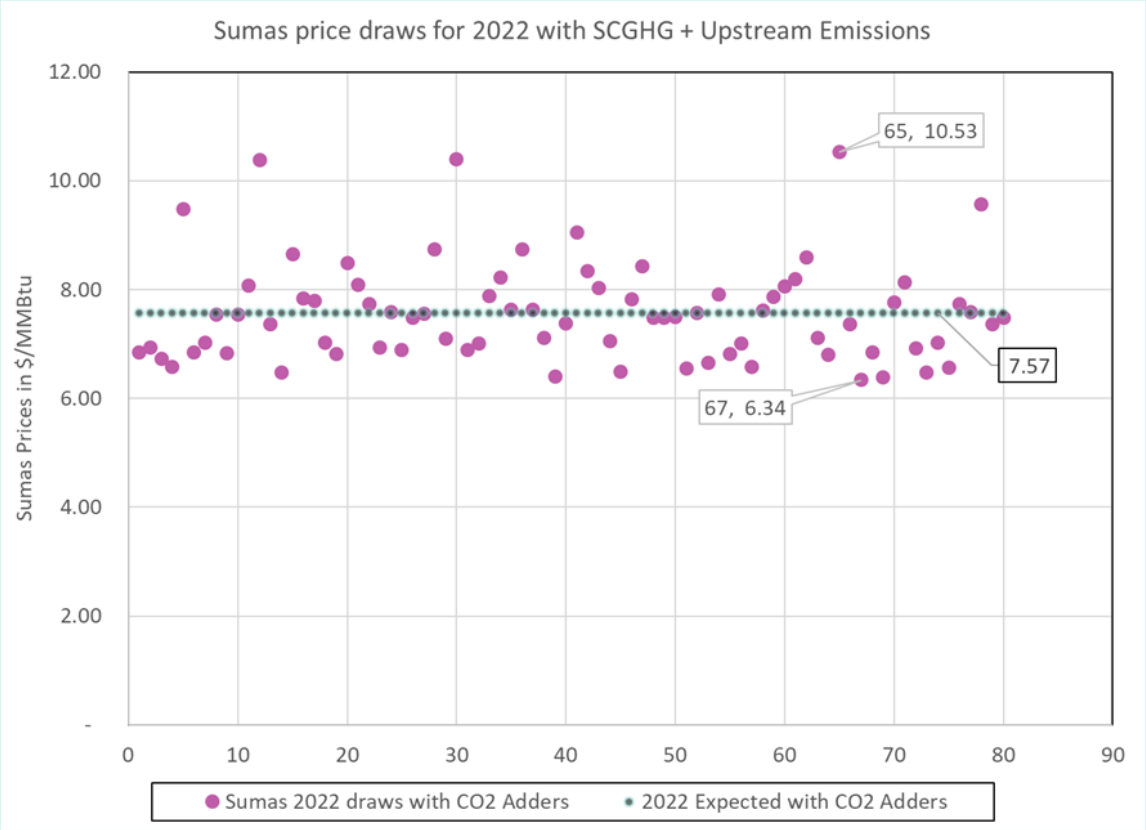
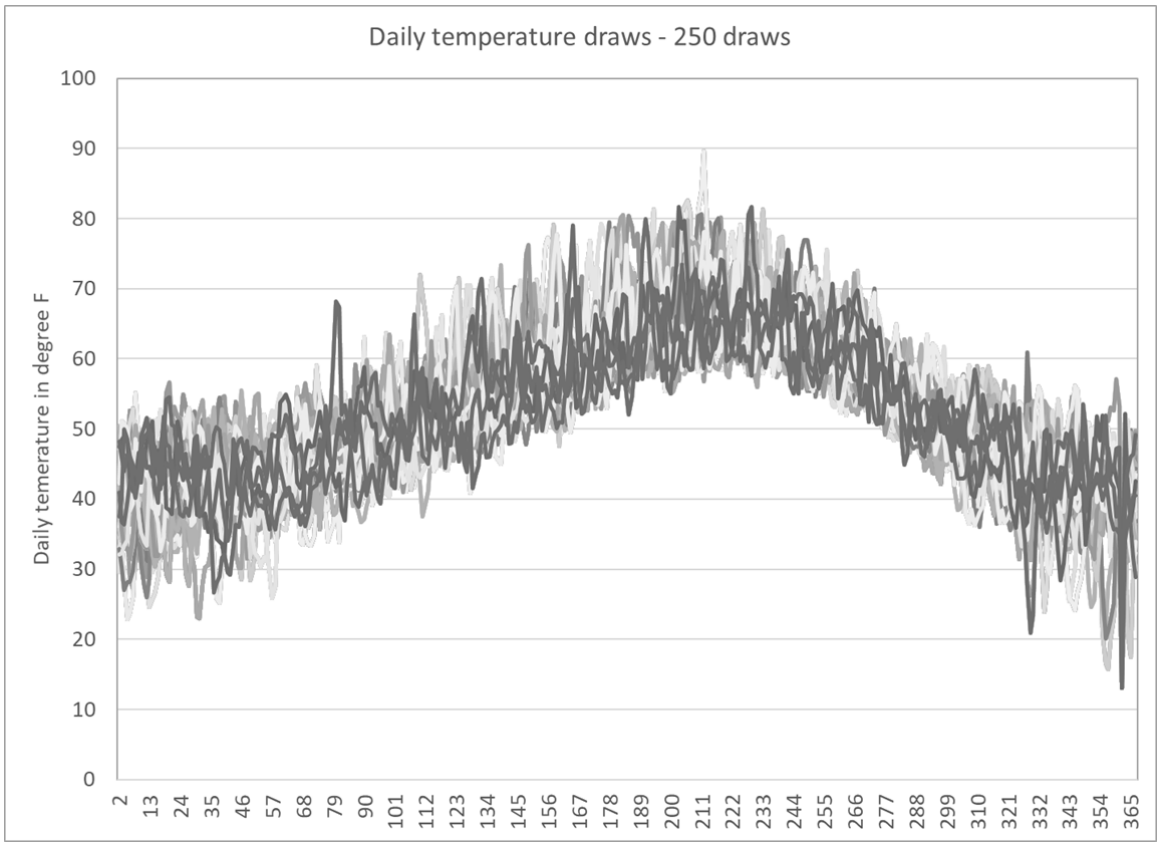


Figure 9-48 – Sumas Price Draws for 2022 after Adjusting for SCGHG and Upstream Emissions Adders



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

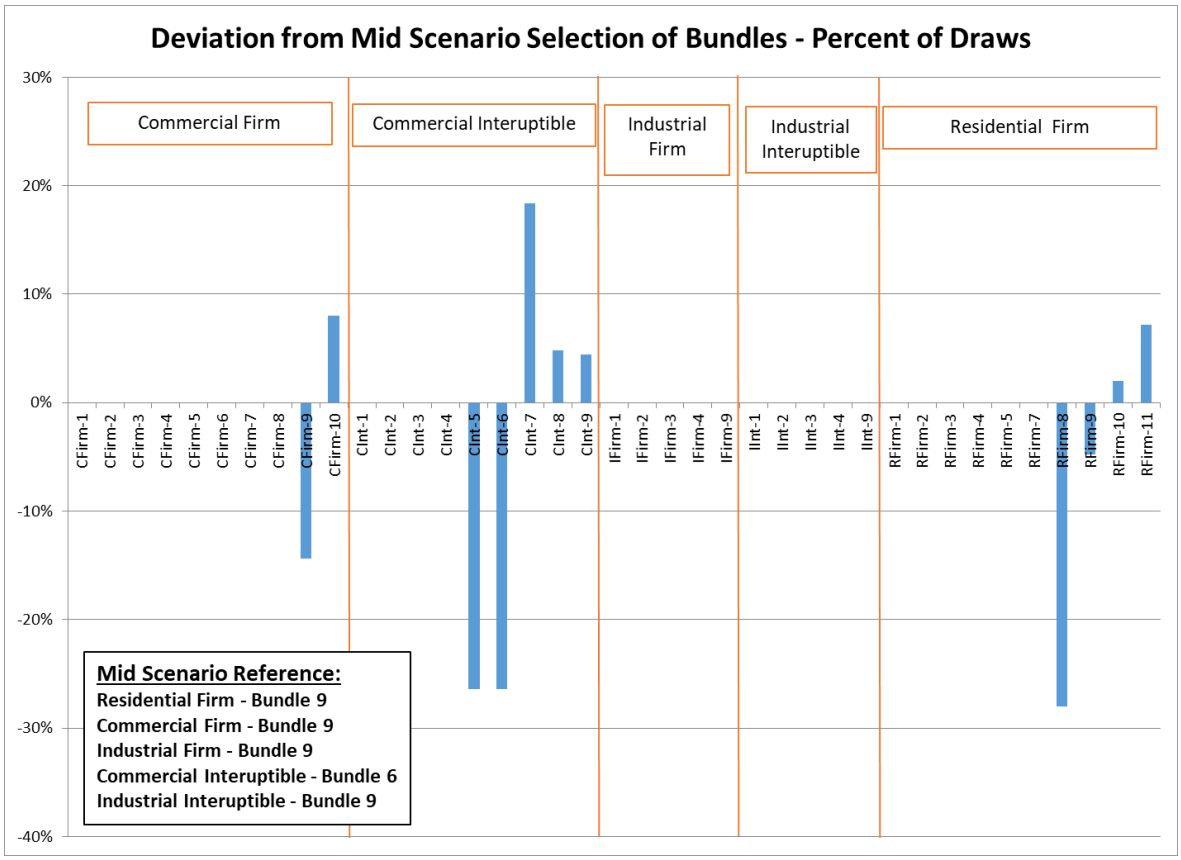
Figure 9-49 – Daily Temperature Draws for Demand



Stochastic Analysis Results

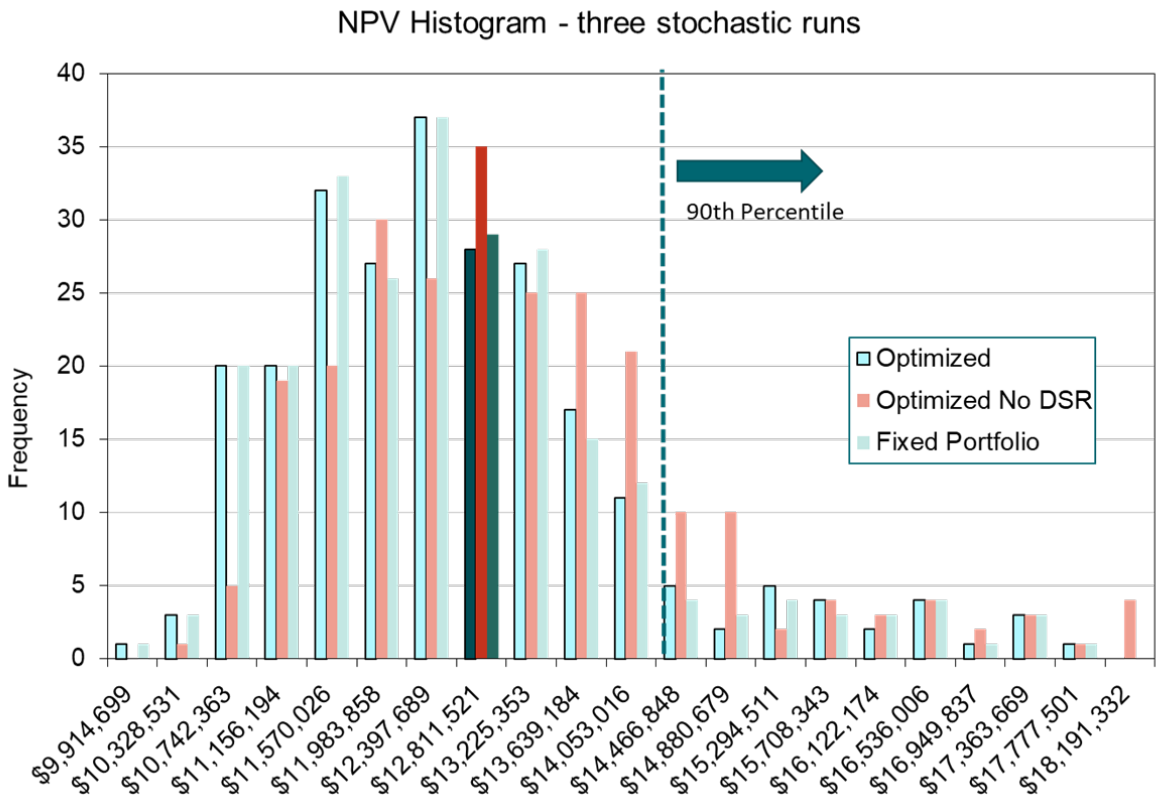
In the 250 optimal portfolios built in the stochastic analysis, the results showed that the DSR quantity chosen in the deterministic scenarios held up in over 80 percent of the draws as shown in Figure 9-50. Therefore, the risk of over-building or under-building DSR appears to be low.

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



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

Figure 9-51: Distribution of Portfolio System Costs



6. NATURAL GAS DELIVERY SYSTEM ANALYSIS

Overview

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

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

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

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

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

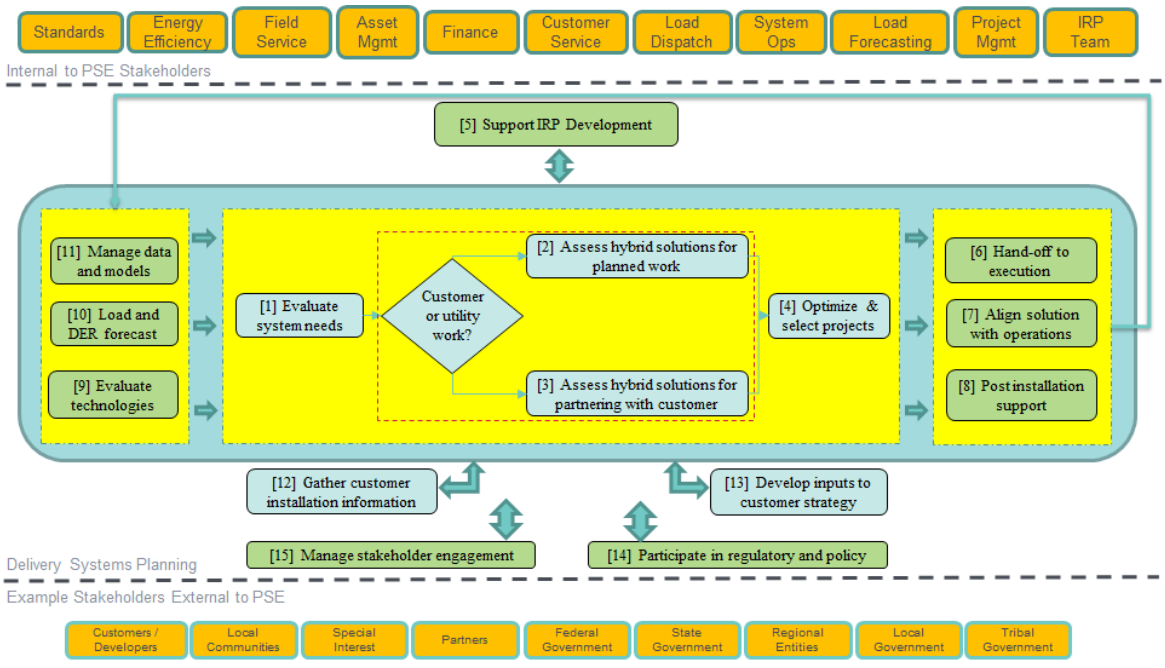
alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term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

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

Analysis Process and Needs Assessment

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

Figure 9-52: PSE Delivery System Planning Operating Model





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

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

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

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

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

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

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

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

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

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

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy, are also included in the system evaluation. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement in 2012 allowing natural gas utilities to file a plan for replacing pipes that

represent a higher risk of failure, and PSE's commitment to this plan is considered in the evaluation. In 2016, the NTSB recommended the pipeline industry develop guidance on safe pipeline operations to ensure protection of communities and the environment. The Pipeline Safety Management System (PSMS) helps operators understand, manage and continuously improve safety efforts at any stage of their safety programs through a Plan-Do-Check-Act cycle. The PSMS is intended to provide the tools needed to continuously and comprehensively track and improve safety performance. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As transportation projects develop through design, engineering and construction, PSE works with local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs.

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

Figure 9-53: Natural Gas Delivery System Planning Tools

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

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

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

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

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

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

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

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

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

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

Solutions Assessment and Criteria

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

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

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

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

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

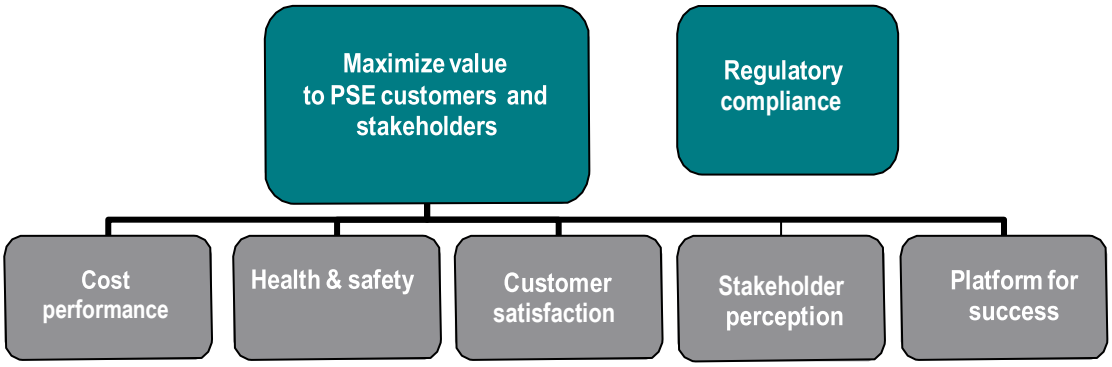
The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

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

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

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

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



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

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

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

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

Non-pipe Alternative Analysis

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

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

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

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

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

16 / RCW 80.28.190
17 / RCW 80.28.110

Project Planning and Implementation Phase

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

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

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

COUNCIL STUDY SESSION

ENERGY STORAGE SYSTEM MORATORIUM ORDINANCE NO. 6978

PRESENTED BY
GABRIEL CLARK, PLANNER II
APRIL 28, 2025

Department of Community Development
Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE
ENVIRONMENT
ECONOMY
CHARACTER
SUSTAINABILITY
WELLNESS
CELEBRATION

WHAT ARE ENERGY STORAGE SYSTEMS?

- Energy Storage Systems (ESS) vary widely in their uses and installation types; their primary function is to store electrical energy during periods of low demand and discharge at periods of high demand.
  - Battery Energy Storage Systems (BESS) are a type of ESS which uses battery technology to provide storage and improve the overall stability of the electrical grid.

- Other functions include:
  - Load Shedding
  - Load Sharing
  - Smoothing and dispatching from renewable energy sources
  - Emergency power storage

- **<u>The moratorium covers all ESS, BESS is the primary concern for Staff.</u>**

WHY A LITHIUM-ION BATTERY?

- Lithium-ion batteries are a very common method of storing electrical energy for usage and may be charged and discharged reliably.
- Examples:
  - Phone batteries
  - Laptop computers
  - Electric Vehicles







WHAT ARE THE DIFFERENT TYPES?

Residential



Moratorium

Commercial

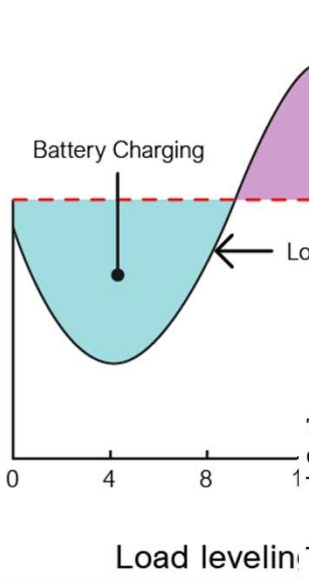


Grid



SERVICE • ENVIRONMENT • ECONOMY • CHARACTER • SUSTAINABILITY • WELLNESS • CELEBRATION

PRIMARY FUNCTIONS VISUALIZED



Load levelin

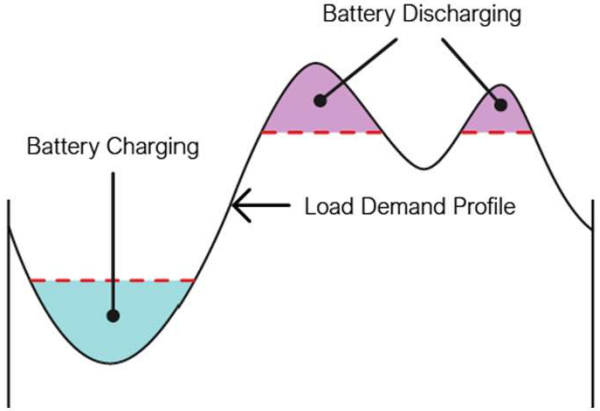
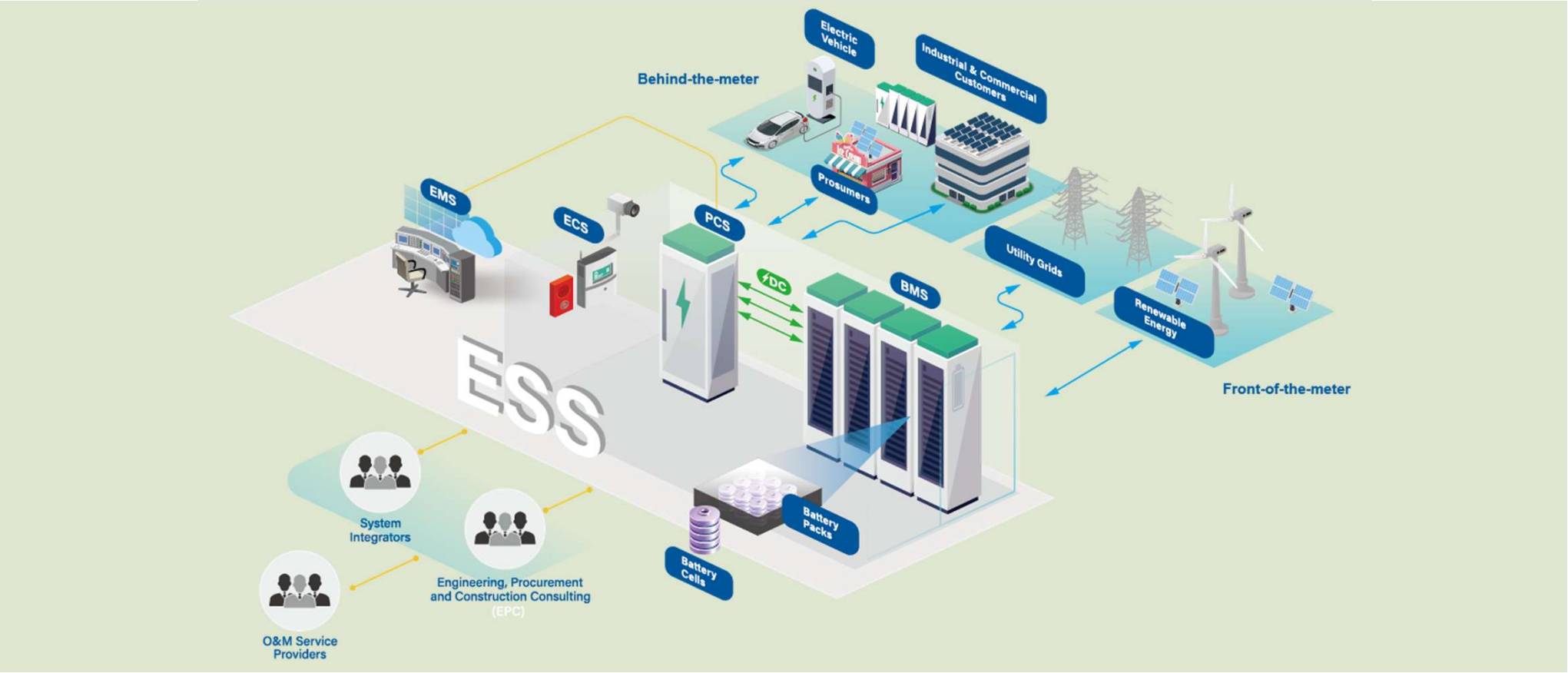


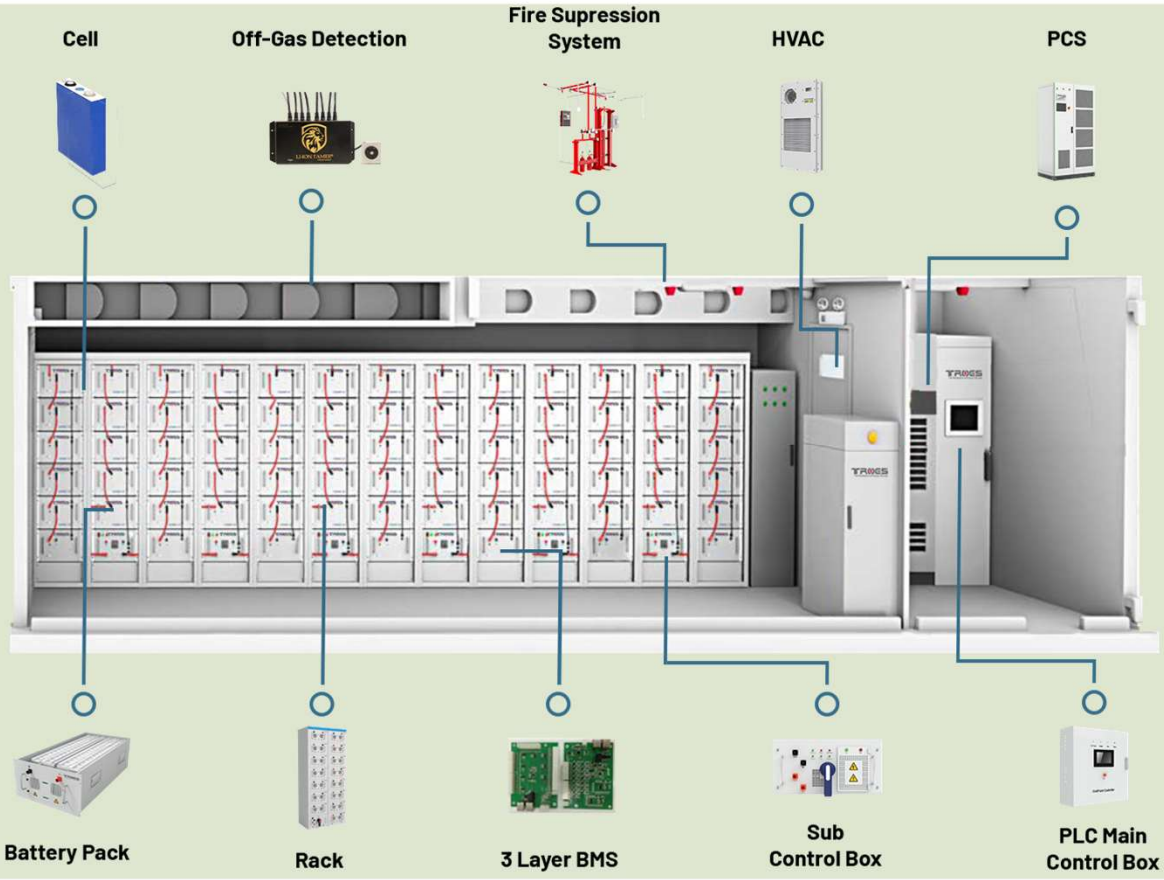
Table 14
General technical specifications of energy storage techniques [1,10,186,187].

Energy storage system	Power Rating	Discharge	Energy density Wh/kg	Energy cost €/KWh	Lifetime Efficiency
PHSS	100–4000 MW	1 hr–24 h	0.5–1.5	50–150	70–85 %
FES	0.002–20 MW	msec to 40 Min	5–130	1000–3500	90–95 %
CAES	50–300 MW	1he- 24 h	30–60	10–120	70–80 %
Ni-CD	0.001–0.1 MW	0.0003–1 h	40–60	200–1000	60–91 %
Li-ion	0.001–0.1 MW	0.0167–1 h	75–250	200–1800	85–100 %
Nas	0.5–50 MW	0.0003–2 h	150–240	200–900	85–90 %
Hydrogen	0.001–50 MW	14 hr- 24 h	800–10000	1–15	20–50 %
Supercapacitor	0.01–1 MW	msec to minute	0.1–15	300–4000	90-95^
SMES	10 kW-10MW	msec to seconds	0.5–5	700–7000	80–90 %

FLOW MAP OF TIER II AND III SYSTEMS



CROSS SECTION OF A BESS CABINET



WHAT ARE THE IMPACTS OF BESS SYSTEMS?

- **Primary Impact: Thermal Runaway**

NEWS

California moves to impose more control over BESS in wake of Moss Landing fire

By April Bonner

March 5, 2025

US & Canada, Americas | Grid Scale | Policy

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Aerial view of the Moss Landing site, including the Vistra natural gas plant which the site is historically better known for. Image: LG Energy Solution.

In the wake of the Moss Landing Energy Storage Facility fire, regional and state-wide California authorities have proposed or passed legislation tightening control of BESS projects.

On the afternoon of 16 January 2025, a fire broke out at Moss Landing Energy Storage Facility in Monterey County, California, US, prompting the evacuation of 1,200 to 1,500 local residents.

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Site safety measures help limit spread of fire at 600 MWh BESS in England

It took 24 hours for the firefighters to tackle the blaze at Statera's 300 MW/600 MW



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the fire in

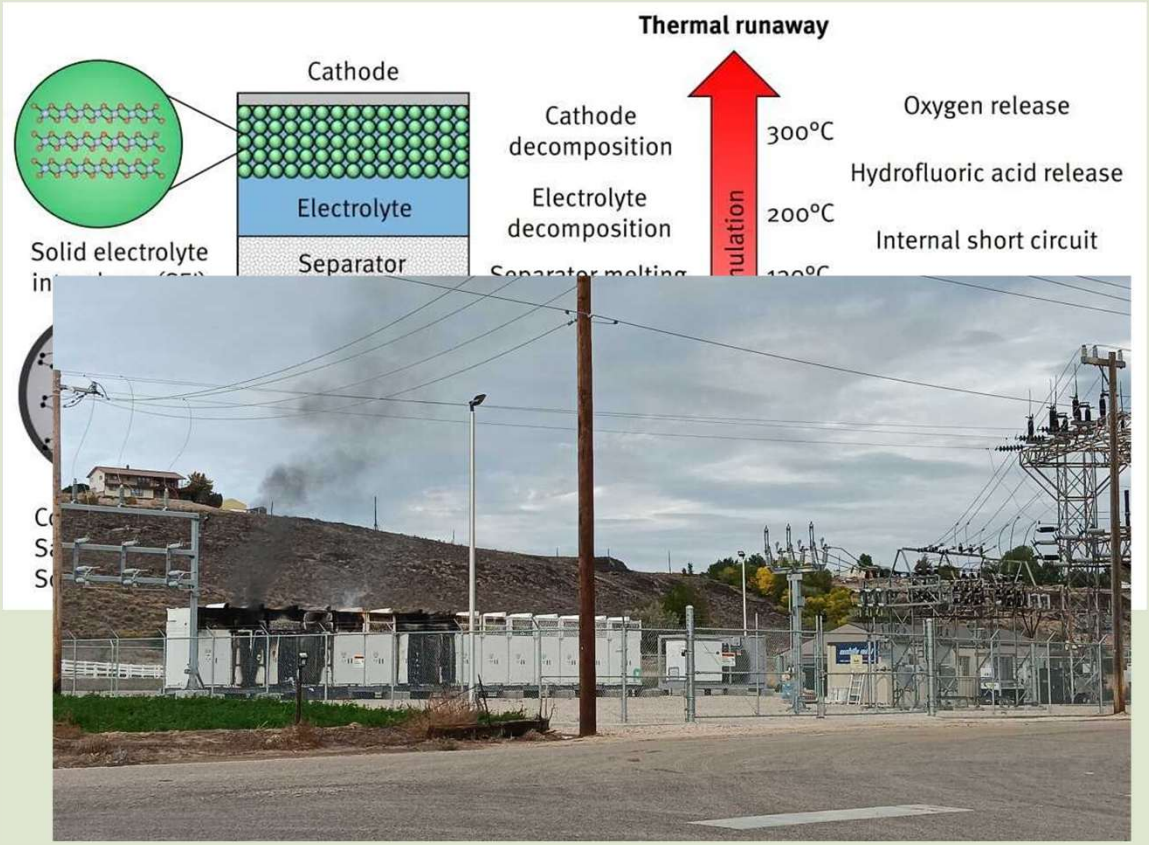
s and

drones, to monitor temperatures and manage the fire in a controlled manner, and water to prevent heat transfer. The crews handed the scene over to the site management on the next day.

WHAT IS THE CAUSE OF THESE FIRES?

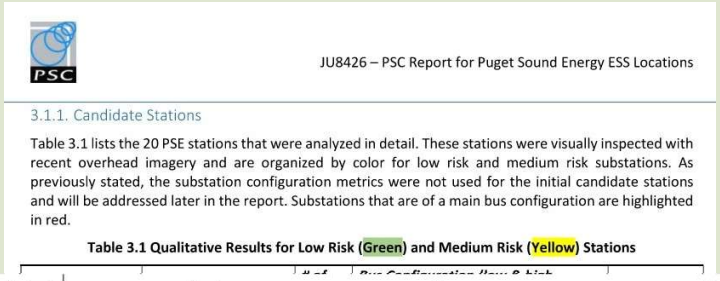
- Thermal Runaway:
  - "A primary risk related to Lithium-ion batteries. It is a phenomenon in which the Lithium-ion cell enters an uncontrollable, self-heating state." – UL Research Institutes

- To reduce the likelihood of thermal runaway, the batteries need to be isolated, cooled, and monitored.



WHAT IS THE DEMAND?

- PSE Hired Power Systems Consultants to report the most viable sites in the service area.
  - Christopher Substitution cited as “low risk”
- Puget Sound Energy announcing two BESS projects in the State.
  - Appaloosa Solar Project (Garfield County)
  - Greenwater BESS Project (Sumner)



JU8426 – PSC Report for Puget Sound Energy ESS Locations

3.1.1. Candidate Stations

Table 3.1 lists the 20 PSE stations that were analyzed in detail. These stations were visually inspected with recent overhead imagery and are organized by color for low risk and medium risk substations. As previously stated, the substation configuration metrics were not used for the initial candidate stations and will be addressed later in the report. Substations that are of a main bus configuration are highlighted in red.

Table 3.1 Qualitative Results for Low Risk (Green) and Medium Risk (Yellow) Stations

Puget Sound Energy adds two new clean energy projects in Washington

The new projects will add almost 350 MW of clean energy from utility scale solar and battery energy storage

BELLEVUE, Wash. (9/24/2024) Puget Sound Energy (PSE) is proud to announce two large projects in Washington state that will help add more clean energy to its portfolio.

The first is the development of a utility-scale solar facility known as Appaloosa Solar Project that PSE will own and operate. The second is a power purchase agreement signed with BrightNight for a Battery Energy Storage System (BESS) known as the Greenwater project.

Together, the projects can generate up to 342 MW of energy to help PSE's commitment to diversify its renewable resource mix and meet the state's Clean Energy Transformation Act (CETA) targets.

Since the passage of CETA in 2019, PSE has added more than 3,800 MW of renewable energy resources to its resource mix. More than half (2,033 MW) of that comes from new resources from 11 projects built to serve the energy needs of our customers.

WHAT IS THE REASON FOR THE MORATORIUM?

- Tier I (residential) BESS installations have limited negative impacts and will not be considered under this moratorium.
- Tier II and Tier III facilities may pose impacts to the safety, well-being and health to the residents and business in Auburn.
- The moratorium will provide needed time for the City to research these impacts and develop regulatory standards.
- **Community Development and Public Works need to develop effective siting, construction, and operation regulations.**

WHAT IS THE JURISDICTIONAL RESPONSE?

- Meetings with Valley Regional Fire Authority (VRFA) concluded the main method of extinguishing fires at BESS facilities is to continually douse the compromised rack with cool water.
- VRFA would be required to post several units at the site, for a multi shift response (12+ hours) and treated as a hazardous materials response.
- A fire would require a significant response. VRFA, Auburn Police, Department of Ecology, Puget Sound Clean Air Agency and other agencies.
- Community Development Staff are developing a new chapter in Title 18 to facilitate the siting, construction, and operation of BESS projects.

WHAT STANDARDS?

Existing

- International Fire Code (IFC) and National Fire Protection Association (NFPA)
  - Chapter 12 of the Washington State IFC (Est. March 2024)
  - 2023 edition of the NFPA 855 Standard Installation of Stationary Energy Storage Systems
- International Building Code (IBC) siting and construction standards.

Absent

- Comprehensive guidance on siting, construction, and operation of ESS facilities.
  - Title 18 Zoning for siting and operation.
  - Engineering Design Standards (EDS)

PROPOSED TIMELINE

May	• Adopt Moratorium
Jun	• Research and program development
Jul	• Prepare zoning text amendment
Aug	• Present proposed text amendment to planning commission
Sep	• Present proposed text amendment to City Council
Oct	• Adopt amended code and moratorium expires

Department of Community Development

Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

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ORDINANCE NO. 6978

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF AUBURN, WASHINGTON, RELATING TO ADOPTION OF A TEMPORARY 6-MONTH MORATORIUM ON THE ACCEPTANCE, PROCESSING, AND/OR APPROVAL OF APPLICATIONS FOR BUILDING AND LAND USE DEVELOPMENT PERMITS AND RELATED LAND USE DECISIONS FOR ENERGY STORAGE SYSTEM FACILITIES PROPOSED TO BE LOCATED WITHIN THE CITY OF AUBURN

WHEREAS, Energy Storage Systems (ESS) including Battery Energy Storage Systems (BESS) are defined as installations designed to store critical electrical energy for later use, typically consisting of batteries, power conversion systems, and control equipment, a primary function of Energy Storage Systems is to store excess electricity generated by the grid during periods of low demand or high renewable energy production, such as from solar or wind sources, the stored energy can then be discharged when demand is high or when renewable energy generation is low, stabilizing the electrical grid and improving overall efficiency and reliability;

WHEREAS, the City's development regulations, specifically the land use category of "Utility facilities and substations" in ACC 18.07.030 and "Utility transmission or distribution line or substation" in ACC 18.23.030, are not currently defined to include the recent technological changes and business models in Energy Storage Systems or supporting infrastructure;

WHEREAS, the City's development regulations, specifically the land use category of "Utility facilities and substations" in ACC 18.07.030 and "Utility transmission or

distribution line or substation" in ACC 18.23.030, are understood to include public regional utility (PSE) agencies that provide public services such as transformers, substations, pumpstations and smaller scale grid infrastructure;

WHEREAS, ESS are primarily financed and constructed by private corporations and leased to energy utilities for maintenance and operation;

WHEREAS, applying the current regulations in Title 18 ACC to new technologies and business models could lead to approval of ESS projects that are undesirable, unsafe, and/or inconsistent with long-term planning goals and objectives of the City, particularly when the existing regulations have not been reviewed and updated for the best practices nor reconsidered in light of technological changes and potential impacts ESS facilities have on the surrounding areas and community resources;

WHEREAS, thermal runaway is a primary risk related to lithium-ion batteries, a phenomenon in which lithium-ion cells enter an uncontrollable, self-heating state, resulting in ejection of gas, shrapnel, and/or particulates, extremely high temperatures, smoke, and fire;

WHEREAS, the Auburn City Council makes the following findings of fact in support of a moratorium under RCW 36. 70A.390, and identified the following unknown risks and economic factors, that may be relevant in assessing the desirability of, and siting concerns associated with, ESS in the City:

A. The City currently does not have specific zoning or development standards applicable to ESS;

B. ESS can be facilities of any type that store electrical energy in potential

kinetic energy, mechanical energy or electrochemical energy when demand on the grid is low and can discharge back into the grid when demand for electricity is high, or electrical energy production is low;

C. In the instance of electrochemical or battery energy storage systems (BESS), lithium-ion batteries are commonly used due to their availability, capacity, efficiency, and general reliability, the chemical composition of lithium-ion batteries may pose increased risk to life and property in the event of thermal runaway or gaseous vapors being released during an emergency;

D. Thermal runaway at a BESS presents a significant burden to emergency personnel as fires may burn for an inordinate amount of time, requiring increased lengths for monitoring and containment, leaving other areas of the City vulnerable due to longer response times;

E. Exceptional amounts of water is required in the event of a thermal runaway to protect other cells from reaching a critical temperature and to suppress the compromised cell, the water used to control the emergency may contain hazardous chemicals and materials such as cyanide and hydrofluoric acid that may leach into the City's protected critical areas identified in Chapter 16.10 ACC;

F. Due to the exceptional amounts of water required to suppress a thermal event, it is not known if the City, or the surrounding water districts have the capacity to provide a constant flow of high-volume water;

G. BESS may create potentially hazardous air quality concerns in the event of an emergency;

H. In the event of an emergency, the response may pose a strain on the first responder personnel that is not fully understood;

I. In the event of an emergency, it is unknown what the impacts to regional transportation routes, businesses, and residents if an evacuation zone is established;

J. ESS may produce noise and visual impacts that are not currently well understood;

K. ESS may produce impacts to wildlife that are not currently well understood;

L. ESS facilities located within the L-F Airport Landing Field District may pose a significant risk to public health, safety, and welfare if an aircraft collision occurs;

M. ESS facilities and their supporting infrastructure may be more appropriate for the industrial (M-1 and M-2) zones in the City due to their scale, land use, and potential impacts to life and safety of the general public;

N. The Washington State Department of Ecology has initiated studies into ESS and is working to provide guidance on how ESS may impact the surrounding environment, and the City wishes to study the results of Ecology's efforts before updating its zoning and other regulations applicable to ESS facilities;

O. The Washington State Legislature adopted House Bill 1216 in 2023 which established the Interagency Clean Energy Siting Coordinating Council to

identify actions to improve siting and permitting of clean energy projects within the State;

P. Puget Sound Energy (PSE), hired PSC (Power Systems Consultants) to conduct an Energy Storage System Location Study detailing locations of potential BESS facilities connected via high-voltage transmission lines to PSE's regional substations, siting (Exhibit H) the Christopher Substation for initial low risk ESS interconnection;

Q. It is unknown what fiscal or economic development benefits would be realized by the City if ESS facilities were permitted within the City or which zone(s) would be suitable for siting them. Further investigation and analysis of the potential economic impacts and tax revenues associated with such projects is warranted;

R. The City does not currently have ESS facilities or locations incorporated or accounted for in an emergency management response plan. ESS present unique emergency management needs that require coordination between the City, its departments, and outside entities;

WHEREAS, the unique characteristics of ESS facilities, certain existing requirements in Code may not be appropriately address or mitigate the community impacts and risks such facilities may present;

WHEREAS, the City Council held a public hearing on 7:00 PM on May 5, 2025, and is adopting the findings contained herein after the conclusion of said public hearing;

WHEREAS, to promote public health, safety, and welfare, the City Council deems

it necessary and proper to impose a moratorium on land use and development permit applications related to ESS for a period of six (6) months;

WHEREAS, processing applications for land use approvals, development permits, and related applications or code interrelations for ESS facilities under exciting zoning code regulations and other official controls could potentially result in approvals of undesirable and incompatible development until such time that the City has properly reviewed its regulations and implemented any zoning code revisions or additional controls deemed necessary and proper for the health, safety, and general welfare of the City and its residents;

WHEREAS, it would be an efficient use of resources and an appropriate exercise of its planning authority under the Growth Management Act and Chapter 35A.63 RCW for the City to analyze whether, and under what regulatory parameters, ESS Energy Storage Systems should be allowed uses within the City;

WHEREAS, the City possesses land use jurisdiction and regulatory authority over the City's incorporated lands;

WHEREAS, the adoption of this moratorium is exempt from the threshold determination requirements under the State Environmental Policy Act;

WHEREAS, the potential adverse impacts on public health, property, safety, and welfare of the City and its citizens if this moratorium does not take effect immediately, further justifies a moratorium under RCW 36.70A.410 and the designation of this ordinance as necessary for the protection of public health, public property, or the public peace by the Council, the moratorium imposed herein promotes the public good and is

necessary for the protection of public health, property, safety, and welfare; and

NOW THEREFORE, THE CITY COUNCIL OF THE CITY OF AUBURN, WASHINGTON, DO ORDAIN AS FOLLOWS:

Section 1. Findings of Fact.

The recitals set forth above as well as Exhibits A through I are hereby adopted as the City Council's findings of fact in support of the moratorium established by this ordinance.

Section 2. Moratorium Imposed.

Pursuant to RCW 35A.63.220, and RCW 36.70A.390, a temporary moratorium is hereby imposed upon Tier II and Tier III ESS facilities in any zone within the City of Auburn. This moratorium also applies to the City's acceptance, processing, or approval of any applications, building permits, and land use permits for ESS facilities including without limitation;

A. Administrative Use permits;

B. Conditional Use permits;

C. Building permits;

D. Grading permits;

E. Short plats;

F. Subdivisions;

G. Binding site plans;

H. Reasonable use exceptions;

I. Variances from Title 18 ACC regulations;

J. Deviations from any City of Auburn engineering design and construction standards or other technical codes for ESS facility within the City or any other type of development permit, approval, or code interpretation in connection with the same; and

K. Any other development permits related to ESS facilities.

The moratorium codified herein shall not apply to Tier I residential Battery Energy Storage Systems that serve as a back-up source of energy, load shedding, and storage of solar energy. Fires and other emergencies typically seen from Tier I BESS are limited in their impacts to the safety, welling, and health of Citizens.

Section 3. Term of Moratorium.

The moratorium imposed by this Ordinance shall become effective on the date described in Section 8, and shall continue in effect for an initial period of six (6) months, unless repealed, extended or modified by the City Council after subsequent public hearing(s) and entry of appropriate findings of fact pursuant to RCW 35A.63.220, provided that the moratorium shall automatically expire upon the effective date of zoning and land use regulations adopted by City Council to address siting, construction, and operation of ESS located within the City of Auburn.

Section 4. Public Hearing.

Pursuant to RCW 35A.63.220 and RCW 36.70A.390, the City Council has held a public hearing at the City Council's regular meeting at 7:00 PM on May 5, 2025, in order to take public testimony on this moratorium.

Section 5. Severability, Constitutionality and Invalidity.

If any section, subsection sentence, clause, finding, phrase, or portion of this Ordinance, is for any reason held invalid or unconstitutional by any Court of competent jurisdiction such portion shall be deemed a separate, distinct and independent provision, and such holding shall not affect the validity of the remaining portions thereof.

Section 6. Corrections.

Upon the approval of the City Attorney the City Clerk and the codifiers of this ordinance are authorized to make any necessary corrections to this ordinance including, but not limited to, the correction of scrivener's/clerical errors, references, ordinance numbering, section/subsection numbers, and any reference thereto.

Section 7. Implementation. The Mayor is authorized to implement such administrative procedures as may be necessary to carry out the directions of this legislation.

Section 8. Effective Date.

This Ordinance shall take effect and be in force five (5) days from and after its passage, approval and publication as provided by law.

Section 9. Ordinance Transmitted to State.

Pursuant to RCW 36.70A.106, a copy of this ordinance shall be transmitted to the Washington State Department of Commerce.

INTRODUCED: MAY 05 2025

PASSED: MAY 05 2025

APPROVED: MAY 05 2025

NANCY BACKUS, MAYOR

ATTEST:

Shawn Campbell, MMC, City Clerk

APPROVED AS TO FORM:

Jason Whalen, City Attorney

Published: _____

Seattle Trades

Nicole– electrical

Josh Rogers - VRFA

Mike Holman - VRFA

MIT Planning director

Dave – Sr. Pl MIT

Julian – PSE

Q 1 – How do BESS impact the existing grid infrastructure?

PSE Projected area need 1500 MW of BESS – Peak Shaving (hot or cold), January cold snap, summer heat wave, high demand for heat or colling equipment, tech to modernize the grid, using BESS for micro-grids serve small community facility and surrounding homes, home applications, Part of grid infrastructure and future grid, non-emitting power generation and storage cost effective way, 100%, benefit for ratepayers

PSE - 2025 no coal in rates, Jan 1, 2026

Q2 Process – PSE or 3rd party developer needs interconnection requirements, technical requirement needs, infrastructure improvements also needed to bring those online

Large reliability gap starting next year, WA, ID, OR region projected need for energy, data center, building and vehicle electrification = huge energy demand, wind and solar and storage, long-haul transmission

Q 4 – How does the construction and operation support the local workforce?

2,000 licensed electricians, a lot of unemployment, 1,000 unemployed for more than 18-months, people leave for lower cost of living, temporary dip in market, in commercial real estate, offices are empty, transition off of fossil fuel, port and transportation electrification and updating buildings – green energy, use electricity when you need it

Ecosystem of jobs, construction = represents cutting tech, running out of options –

Federal policy changes impacting wind and solar, impacting all across the country, local systems that serve the need of local communities, WA state law has not changed, 2030 80% non-emitting, 50%ish currently

How to combat the fear of BESS, power is out but the water and sewer are still flowing, that is because of BESS.

PSE would not be bringing these facilities online if we believed they were not safe. Here to advise or partner as needed

Safety and Concern – IFC, NFPA 2021 codes, chemistry in the battery (lithium ion), detection, ventilation, fire suppression, alarms, all required in the new facilities…

Training, equipment, etc., find opportunities for training,

Fear = may not be supportive of renewable energy, UL standards (not applied in other countries that other examples are provided from).

Examples for guidance and best practices

Sumner – Greenwater Project 200 MW, Commerce - Arlington, Seattle City Light

Buildings catch fire too, should we not build buildings –

Post fire event?

Root cause of the controversy – when it burning what is the solution – Jan 16, Monterey County 1500 people evacuate, moss landing – different chemistry

Real mitigation and solution, NFPA 1, 855, solution is condensed aerosol fire compression, let burn for a week, foam can be toxic to the environment – health impact, fire suppression

State emergency amendment to adopt 2024 sections of 2021,

Microwave?

EFSEC process is an option,

Proximity to substation –

How can Auburn facilitate the construction of BESS – Tier II – sizes, Accessory 2-8 mW accessory to primary use at the site vs. Community similar to grid style but smaller 10-20 mW local substation, micro communities

DER – Distributed Energy Resources,

Decommissioning, restored to prior or better condition,

Runoff design standards are designed for containment –

Policy disincentivizes community scale power solutions it can become exclusive,

Grid Scale RFP –

B&O Tax?

Julian – Where are the substations

STUDY SESSION

ENERGY STORAGE SYSTEM MORATORIUM EXTENSION ORDINANCE NO. 6995

PRESENTED BY ALEXANDRIA TEAGUE
PLANNING SERVICES MANAGER
OCTOBER 13, 2025

Department of Community Development
Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

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CHARACTER
SUSTAINABILITY
WELLNESS
CELEBRATION

BACKGROUND

- Staff introduced Ordinance No. 6978 to City Council at the Study Session meeting held on April 28, 2025.
- City Council held a public hearing and adopted Ordinance No. 6978 at the May 5, 2025, Council Action meeting.
- RCW 36A.63.220 and RCW 36.70A.390 provide regulatory authority for establishment of moratoria.

PURPOSE

- The extension of the moratorium would allow staff to:
  - Continue to work with industry leaders.
  - Incorporate community & industry feedback into proposed code.
  - Discus the proposed code and findings with Planning Commission.

PROPOSED UPDATED TIMELINE

- **Oct** • Roundtable discussion & adoption of moratorium
- **Nov** • Research and program development
- **Dec** • Prepare zoning text amendment
- **Jan** • Present proposed text amendment to planning commission
- **Feb** • Present proposed text amendment to City Council
- **Mar** • Adopt amended code and moratorium expires

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RECOMMENDATION

Recommendation

Staff requests Council to schedule Ordinance 6995 for action on October 20, 2025.

Department of Community Development

Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

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ORDINANCE NO. 6995

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF AUBURN, WASHINGTON, CONTINUING THE MORATORIUM ENACTED ON MAY 10, 2025, PURSUANT TO ORDINANCE NO. 6978 AND AS AMENDED BY ORDINANCE NO. 6995 ON THE ACCEPTANCE, PROCESSING, AND/OR APPROVAL OF APPLICATIONS FOR BUILDING AND LAND USE DEVELOPMENT FOR ENERGY STORAGE SYSTEM FACILITIES (ESS) PROPOSED TO BE LOCATED IN ANY ZONE WITHIN THE CITY OF AUBURN

WHEREAS, Energy Storage Systems (ESS) including Battery Energy Storage Systems (BESS) are defined as installations designed to store critical electrical energy for later use, typically consisting of batteries, power conversion systems, and control equipment, a primary function of Energy Storage Systems is to store excess electricity generated by the grid during periods of low demand or high renewable energy production, such as from solar or wind sources, the stored energy can then be discharged when demand is high or when renewable energy generation is low, stabilizing the electrical grid and improving overall efficiency and reliability;

WHEREAS, the City's development regulations, specifically the land use category of "Utility facilities and substations" in ACC 18.07.030 and "Utility transmission or distribution line or substation" in ACC 18.23.030, are not currently defined to include the recent technological changes and business models in Energy Storage Systems or supporting infrastructure, but are understood to include public regional utility (PSE) agencies that provide public services such as transformers, substations, pumpstations and smaller scale grid infrastructure;

WHEREAS, applying the current regulations in Title 18 ACC to new technologies and business models could lead to approval of ESS projects that are undesirable, unsafe,

and/or inconsistent with long-term planning goals and objectives of the City;

WHEREAS, the Auburn City Council makes the following findings of fact in support of a moratorium under RCW 36. 70A.390, and identified the following unknown risks and economic factors, that may be relevant in assessing the desirability of, and siting concerns associated with, ESS in the City:

A. The City currently does not have specific zoning or development standards applicable to ESS;

B. Thermal runaway at a BESS presents a significant burden to emergency personnel as fires may burn for an inordinate amount of time, requiring increased lengths for monitoring and containment, leaving other areas of the city vulnerable to high response times;

C. Exceptional amounts of water is required in the event of a thermal runaway to protect other cells from reaching a critical temperature and to suppress the compromised cell, water used to control the emergency may contain hazardous chemicals and materials such as cyanide and hydrofluoric acid that may leach into the City's protected critical areas identified in Chapter 16.10 ACC;

D. Due to the exceptional amounts of water required to suppress a thermal event, it is not known if the City, or the surrounding water districts have the capacity to provide a constant flow of high-volume water;

E. BESS may create potentially hazardous air quality concerns in the event of an emergency;

F. In the event of an emergency, it is unknown what the impacts to regional

transportation routes, businesses, and residents if an evacuation zone is established;

G. ESS may produce impacts to wildlife that are not currently well understood by the City;

H. ESS facilities located within the L-F Airport Landing Field District may pose a significant risk to public health, safety, and welfare if an aircraft collision occurs;

I. ESS facilities and their supporting infrastructure may be more appropriate for the industrial (M-1 and M-2) zones in the City due to their scale, land use, and potential impacts to life and safety of the general public;

J. It is unknown what fiscal or economic development benefits would flow to the City if ESS facilities were permitted within the City;

WHEREAS, the City Council held a public hearing on 7:00 PM on May 5, 2025, to adopt findings following the conclusion of a public hearing of Ordinance No. 6978,

WHEREAS, further discussions with industry leaders are needed to better understand the potential impacts of ESS facilities and to vet proposed code amendments language requested to be performed by staff on behalf of the City,

WHEREAS, the potential adverse impacts on public health, property, safety, and welfare of the City and community of the moratorium authorized under Ordinance No. 6978 expires before staff can complete necessary research, further justifies a moratorium under RCW 35A.63.220 and the designation of this ordinance as necessary for the protection of public health, public property, or the public peace by the Council, the moratorium imposed herein promotes the public good and is necessary for the protection

of public health, property, safety, and welfare;

WHEREAS, to promote public health, safety, and welfare, the City Council deemed it necessary and proper to extend the moratorium on land use and development permit applications related to BESS for an additional period of six (6) months by holding a public hearing on November 3rd, 2025 at 7:00 PM to adopt findings following the conclusion of a public hearing for Ordinance Number 6995;

WHEREAS, it would be an efficient use of resources and an appropriate exercise of its planning authority under the Growth Management Act, Chapter 36.70A RCW, and Chapter 35A.63 RCW for the City to integrate and analyze whether, and under what regulatory parameters, ESS be allowed uses within the City;

WHEREAS, the City possesses land use jurisdiction and regulatory authority over the City's incorporated lands; and

WHEREAS, the adoption of this moratorium is exempt from the threshold determination requirements under the State Environmental Policy Act;

NOW, THEREFORE, THE CITY COUNCIL OF THE CITY OF AUBURN, WASHINGTON, DO ORDAIN as follows:

Section 1. Findings of Fact. The recitals set forth above are hereby adopted as the City Council's findings of fact in support of the moratorium established by this ordinance, The City Council may, in its discussion, adopt additional findings after the public hearing referenced in Section 4 below.

Section 2. Moratorium Imposed. Pursuant to RCW 35A.63.220, and RCW 36.70A.390, a temporary moratorium is hereby extended upon Tier II and Tier III ESS facilities in any zone within the City of Auburn. This moratorium also applies to the City's

acceptance, processing, or approval of any applications, building permits, and land use permits for ESS facilities including without limitation;

A. Administrative Use permits;

B. Conditional Use permits;

C. Building permits;

D. Grading permits;

E. Short plats;

F. Subdivisions;

G. Binding site plans;

H. Reasonable use exceptions;

I. Variances from Title 18 ACC regulations;

J. Deviations from any City of Auburn engineering design and construction standards or other technical codes for ESS facility within the City or any other type of development permit, approval, or code interpretation in connection with the same; and

K. Any other development permits related to ESS facilities.

The moratorium codified herein shall not apply to Tier I residential Battery Energy Storage Systems that serve as a back-up source of energy, load shedding, and storage of solar energy. Fires and other emergencies typically seen from Tier I BESS are limited in their impacts to the safety, well being, and health of the community.

Section 3. Term of Moratorium. The moratorium imposed by this Ordinance shall become effective date described in Section 8, and shall continue in effect for an additional period of six (6) months, provided that the moratorium shall automatically expire

upon the effective date of zoning and land use regulations adopted by City Council to address siting, construction, and operation of ESS located within the City of Auburn.

Section 4. Public Hearing. Pursuant to RCW 35A.63.220 and RCW 36.70A.390, the City Council has held a public hearing at the City Council's regular meeting at 7:00 PM on November 3rd, 2025, in order to take public testimony on this moratorium.

Section 5. Referral to Staff; Work Plan. City Staff and the Auburn Planning Commission are hereby authorized and requested, as part of their ongoing work related to ESS facilities to study the issues identified in this ordinance and to develop recommendations for whether ESS facilities should be allowed uses within the City and, if so, what zoning regulations and public processes are needed to protect the health, safety, and welfare of the community and ensure that such facilities are developed in a manner that is compatible with the overall plan and vision of the City. These recommendations shall be reviewed and considered by the Auburn City Council for inclusion as a Chapter in Title 18 of Auburn City Code and/or other official controls of the City.

A. The City of Auburn Planning Commission shall be authorized and directed to hold public hearings and public meetings to fully receive and consider statements, testimony, positions and other documentation or evidence related to the issue of the ESS, including, but not limited to, regulations related to the siting, construction, and operation.

B. The Planning Commission and City staff are authorized and directed to review the experiences of other jurisdictions, the status of legal cases, and statistical data, information, studies and other evidence compiled by other municipalities, of adverse

impacts of such ESS, and to review State and Federal law and regulations and the regulations, ordinances and codes adopted by other municipalities to address ESS, and any information that is pertinent to consideration of ESS, including but not limited to siting, construction, and operation.

C. The City of Auburn Planning Commission shall work with City Staff and the community of the City to develop proposals for regulation of ESS land use and zoning considerations, to be forwarded in their recommendations to the City Council for inclusion in ordinances and ultimate adoption as a apart of the City Code of the City of Auburn, including regulations related to siting, construction, and operation of ESS.

D. The Mayor, in consultation with the City Attorney, Community Development Director, Public Works Director, Police Chief, Emergency Management, Fire Marshal, and other staff, shall periodically advise and report to the City Council as to the status of hearings, meetings, and information development regarding actives of the Planning Commission and City Staff relative to the evaluation, consideration, and development of regulations concerning ESS, including, but not limited to, siting, construction, and operation, until adoption of a comprehensive ordinance as developed, relating to ESS becoming effective in the conjunction with the termination of the moratorium referred to in this ordinance.

Section 6. Implementation. The Mayor is authorized to implement those administrative procedures necessary to carry out the directives of this legislation.

Section 7. Severability. The provisions of this ordinance are declared to be separate and severable. The invalidity of any clause, sentence, paragraph, subdivision, section, or portion of this ordinance, or the invalidity of the application of it to any person

or circumstance, will not affect the validity of the remainder of this ordinance, or the validity of its application to other persons or circumstances.

Section 8. Effective date. This Ordinance will take effect and be in force five days from and after its passage, approval, and publication as provided by law.

INTRODUCED: NOV 0 3 2025

PASSED: NOV 0 3 2025

APPROVED: NOV 0 3 2025

Nancy Backus
NANCY BACKUS, MAYOR

ATTEST:

Shawn Campbell
Shawn Campbell, MMC, City Clerk

APPROVED AS TO FORM:

Jason Whalen, City Attorney

Published: _____

Responses Overview

Active

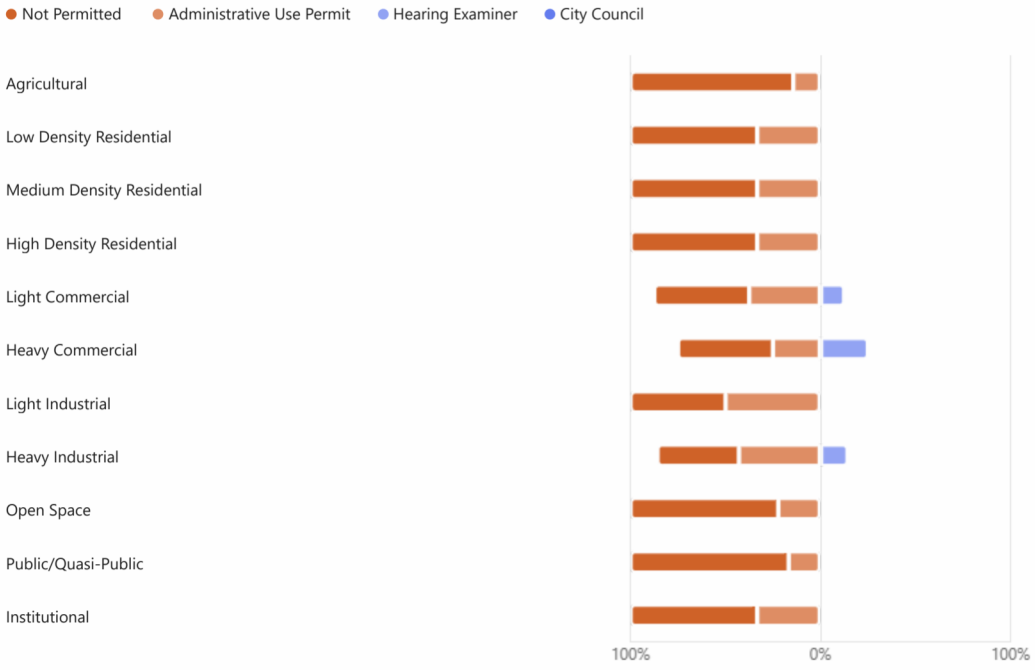
Responses	Average Time	Duration
10	36:24	20 Days

1. Please provide the name of your jurisdiction.

7
Responses

Latest Responses
"City of Kenmore"
"King County"
"City of Kent"
...

2. What is the land use approval process for commercial BESS facilities in your jurisdiction by land use designation?



3. Does your zoning ordinance indicate a storage capacity threshold (in Mega Watts) for commercial BESS stations?



4. If your code does indicate a capacity threshold (MW) what is the capacity?

6
Responses

Latest Responses
"N/A"
"2 MW"
• • •

5. If your zoning ordinance established development standards for commercial facilities, please include your code citations in the text box b elow.

6
Responses

Latest Responses
"N/A"
"King County Code sections 21A.08.030.B.7.d, 21A.08.060.B.18, 21A.08.090.29.B, an... "
• • •

6. Does your jurisdiction have a commercial BESS facility in operation? If so, please include the permit/project number in the field below.

9
Responses

Latest Responses
"No"
"No permits have been issued, and there are no known BESS facilities are in opera... "
"Not to my knowledge - there was a pre-application meeting for one in 2024 RPP... "
• • •

7. If your jurisdiction has adopted a zoning ordinance to regulate commercial BESS facilities, what are themes your department has learned? Has your department made revisions to the zoning ordinance since its passage?

9
Responses

Latest Responses
"N/A"
"No revisions have been made yet; lessons from the legislative and SEPA processe... "
"No - we currently regulate them as a "Utility and transportation facility: electrical ... "
• • •

8. If your jurisdiction has completed project reviews for a BESS facility, please email me a copy of the staff report or other documentation yo u see fit to gclark@auburnwa.gov.

7
Responses

Latest Responses
"N/A"
"No project reviews have been completed. However, in case it's helpful, staff repor... "
• • •

Gabriel Clark

From: Katie Buchl-Morales <KBuchl-Morales@Rentonwa.gov>
Sent: Thursday, October 30, 2025 10:26 AM
To: Gabriel Clark
Cc: CED Planning Customer Service
Subject: FW: Request for Information - Battery Energy Storage Systems Local Practices - Microsoft Forms Link

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

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Hi, Gabriel –

We adopted a BESS ordinance in 2022, which essentially prohibits the use of utility scale BESS in the City of Renton. This decision was based on public input, recent BESS accidents and related evacuations, and lack of resources for jurisdictions. Although we fully understood the need for energy storage as it relates to meeting our climate goals and energy grid resilience, we had some major concerns at the time, including –

1. Existing IFC and IBC (2018) were not adequate
2. Pending updates to 2021 IFC and IBC not effective
3. Concerns from Renton Regional Fire Authority: First responder safety, ability to meet normal level of service standards in the event of a disaster, equipment needs, etc.
4. Pending study from PNNL (I'm not sure if they ever published said study)
5. More education and resources needed.

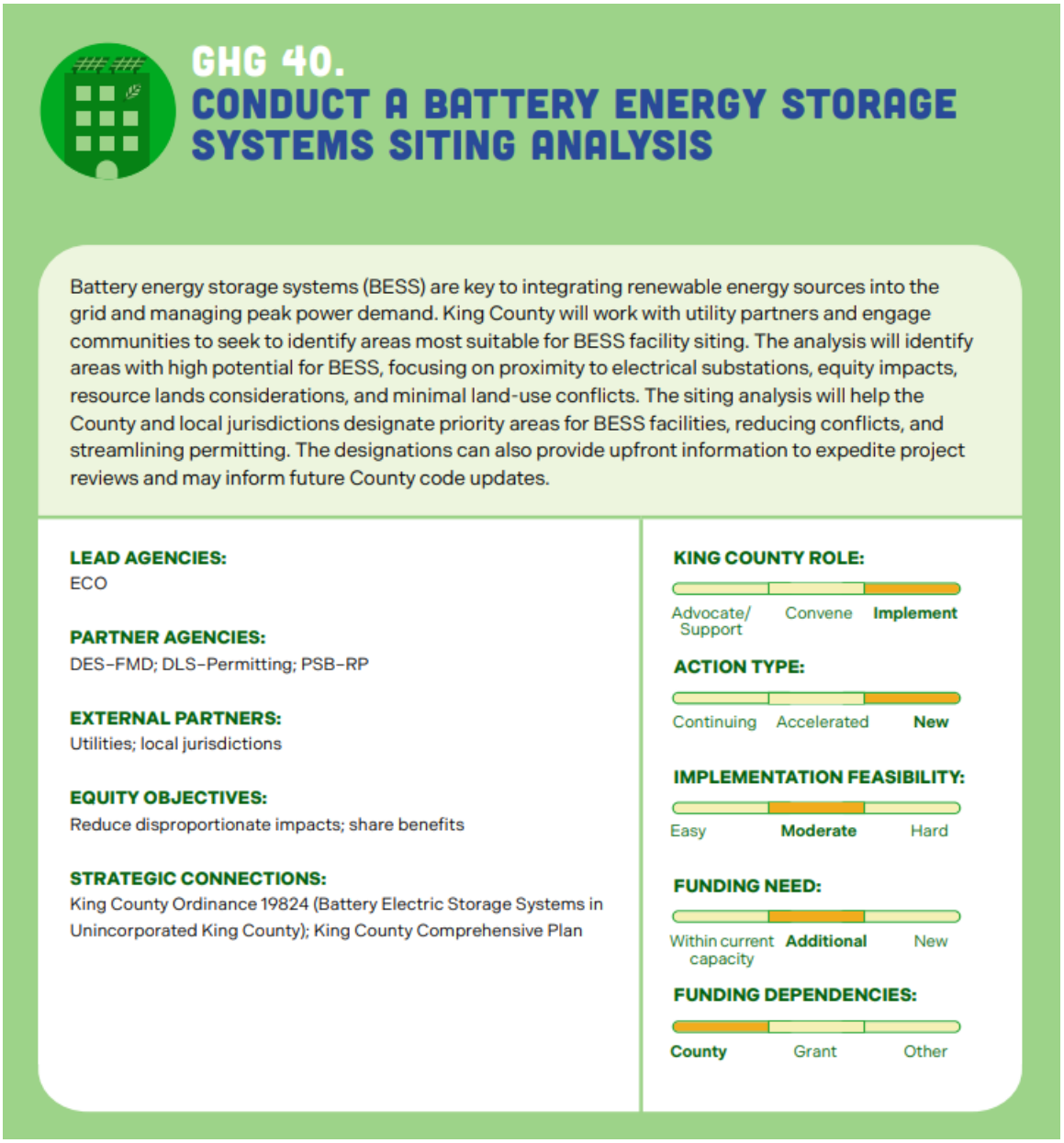
Updates have since been made to the IFC and IBC, but I'm not sure if these address the previous concerns.

FYI – In case you had not already heard, it sounds like there were recent amendments to the King County Strategic Climate Action Plan, which added new items/topics, including BESS. It sounds like King County is planning to conduct a BESS siting analysis in 2026.

Approved by King County Council Committee, going (went?) to full council on 10/7.

Highlights of Council amendments and feedback related to K4C in motion and action/ County Council added some items to the final plan, such as:

1. A new GHG action for the WA state ferries
2. Battery Energy Storage Systems (BESS) action in 2026
3. Pilot projects to explore distributed energy networks
4. Rooftop and community solar policy/advocacy
5. Adding biochar as a regenerative agriculture tool
6. Establishing tree canopy goals
7. Council is interested in seeing the K4C grow and advancing joint climate work across the County



Additional resources:
Nora Hawkins, Senior Energy Policy Specialist at the Department of Commerce.
nora.hawkins@commerce.wa.gov
Jim Anderson-Cook, Director of Development Services at Grant County. jcook@grantcountywa.gov

There was a BESS session at the 2025 APA-WA conference. I was not onsite or unable to attend the session, but I can double-check if the PowerPoint is available through the APA-WA conference portal.

Hope this helps!

KATIE BUCHL-MORALES, Principal Planner
City of Renton // Planning
Virtual Permit Center // Online Applications and Inspections
office 425-430-6578

NOTICE OF PUBLIC DISCLOSURE: This message complies with Washington State's Public Records Act – RCW 42.56

From: Gabriel Clark <GClark@auburnwa.gov>
Sent: Thursday, October 30, 2025 9:11 AM
To: Gabriel Clark <GClark@auburnwa.gov>
Subject: Request for Information - Battery Energy Storage Systems Local Practices - Microsoft Forms Link

CAUTION: This email originated from outside the City of Renton. Do not click links, reply or open attachments unless you know the content is safe.

Good morning,

In response to the growing need for clear development standards related to Battery Energy Storage Systems (BESS) and other emerging energy storage technologies, the City of Auburn is currently evaluating how peer jurisdictions are approaching land use and siting regulations for these facilities.

To support this effort, we've prepared a brief Microsoft Forms questionnaire to gather insights that will inform our local standards. Our goal is to adopt development regulations by late March or early April 2026.

If you or your department would like to receive copies of our materials—including staff reports, presentation slides, or adopted ordinances, and other resources—please don't hesitate to reach out. We're happy to share documentation as it becomes available.

Participation in the questionnaire is entirely optional, and any input you provide is greatly appreciated.

Thank you for your time and consideration.

Microsoft Forms Link.

CODE QUESTIONS?
Book an online meeting: Virtual Permit Center - City of Auburn (auburnwa.gov)

Gabriel Clark, Planner II
Department of Community Development
City of Auburn | www.auburnwa.gov
Office 253-470-2147| gclark@auburnwa.gov
Mailing Address: 25 W Main Street, Auburn, WA 98001
Permit Center Address: 1 E Main Street, Auburn, WA 98002 (Click Here for Map)
Customer Service Survey | Application Forms | Zoning Maps

The information contained in this electronic communication is personal, privileged and/or confidential information intended only for the use of the individual(s) or entity(ies) to which it has been addressed. If you read this communication and are not the intended recipient, you are hereby notified that any dissemination, distribution or copying of this communication, other than delivery to the intended recipient is strictly prohibited. If you have received this communication in error, please immediately notify the sender by reply e-mail. Thank you.

Gabriel Clark

From: Lauren Balisky <BaliskyL@bonneylake.gov>
Sent: Thursday, October 30, 2025 12:35 PM
To: Gabriel Clark
Cc: Planning
Subject: RE: Request for Information - Battery Energy Storage Systems Local Practices - Microsoft Forms Link

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

Good afternoon Gabriel,

I looked at the survey but we do not have a direct corollary to the questions, so I figured an email response would be more helpful. Public utility facilities owned and operated by a public utility are permitted outright in all of Bonney Lake's zoning districts. In residential zones, there are some minor screening requirements (see BLMC 18.22.050 https://ecode360.com/46364866#46364866). We are adding a definition for "public utility" as part of the clarifications associated with our 2024 Periodic update, consistent with state law.

It is our understanding is that PSE has issued an RFP for BESS, and we have gotten mixed information from PSE and a potential respondent on what that would actually entail (indoor / outdoor / owned by the utility / not owned by the utility). If it is not owned by a public utility, it would need to fall under a NAICS code in the land use table, and comply with all of the bulk, performance, and design standards applicable to that zone.

I hope that made sense. Please let us know if you have any follow-up questions.

When Auburn is done gathering its findings, would you be willing to share with all of the jurisdictions that responded?

Sincerely,

Lauren Balisky, AICP, MPA | Development Services Manager

City of Bonney Lake | Public Services Center

21719 96th Street E | Floor 2 | Buckley, WA 98321

Direct: (253) 447-4347 | BaliskyL@bonneylake.gov

Permit Center | (253) 447-4356 | Inspections: (253) 447-4357

Hours: M – Th, 9 AM – 4 PM | F, By Appointment Only | Closed Holidays

Disclaimer: The Development Services Division tries to provide timely and informative responses to all email inquiries, but our responses should not be considered comprehensive or applicable to all situations. Information provided by our staff does not constitute a formal statement of restrictions, legal advice, or a binding determination of development potential. Nothing in this communication shall be deemed to create any liability on the part of the City.

Property owners seeking definitive land use information pursuant to RCW 35A.21.280 should submit a written request to planning@bonneylake.gov. Property owners wanting a more detailed review of a potential project can also request a Pre-Application Meeting ($300).

All email, including attachments, sent to or from the City of Bonney Lake are public records and may be subject to disclosure pursuant to the Washington State Public Records Act (RCW 42.56).

From: Gabriel Clark <GClark@auburnwa.gov>
Sent: Thursday, October 30, 2025 9:11 AM
To: Gabriel Clark <GClark@auburnwa.gov>
Subject: Request for Information - Battery Energy Storage Systems Local Practices - Microsoft Forms Link

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Microsoft Forms Link.

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CITY OF _____

ORDINANCE NO. _____

AN ORDINANCE AMENDING CHAPTER X.X OF THE CITY LAND USE CODE TO DEFINE AND REGULATE BATTERY ENERGY STORAGE SYSTEMS.

WHEREAS, the State Legislature has enacted the Washington Clean Energy Transformation Act to initiate a transition to a clean energy economy, including specific goals for the reduction of greenhouse gas emissions;

WHEREAS, the Washington Clean Energy Transformation Act requires that electric utilities generate 100% non-emitting power by 2045;

WHEREAS, the transition to clean energy generation resources increases our collective reliance on renewable and variable energy sources;

WHEREAS, renewable energy resources, and particularly solar and wind energy, reduce the climate change impacts of electrical generation, but the availability of these resources cannot be controlled;

WHEREAS, battery energy storage facilities smooth out energy supply, ensuring a consistent flow to the grid during periods of fluctuating supply and demand;

WHEREAS, with all infrastructure, safety is a paramount concern when siting BESS facilities and, for those reasons, nationally recognized certification and testing laboratories, such as Underwriters Laboratories ("UL"),the National Fire Protection Association ("NFPA"), the American National Standards Institute ("ANSI"), and the Institute of Electrical and Electronic Engineers ("IEEE"), have developed safety standards for testing, installation, and operation of BESS facilities;

WHEREAS, with all clean energy resources, technologies may also change over time, and for that reason local regulations should build in flexibility to ensure safety and performance standards are complied with over time;

WHEREAS, battery energy storage systems do not result in land use impacts that are greater than those already contemplated for other uses in the local land use codes including "utility" uses that classify electric transmission infrastructure such as the substations to which many standalone BESS are connected;

WHEREAS, the potential impacts of a battery energy storage system may be mitigated through the implementation of siting and development standards, consistent with how local codes already regulate other land uses, and can rely on the robust section of building code regulations that directly addresses and imposes adequate standards to resolve those concerns. International Fire Code Section 1207 adopted by Washington Legislature in WAC 51-54A-1207 is one such example of building code developed with input from technical experts, and represents state of the art regulatory control over the evolving technology;

WHEREAS, most modern BESS facilities are developed according to strict safety certification standards, including but not limited to UL 9450, and NFPA 70, and that compliance with these standards and certifications will adequately address the risks of battery technology through site and component design by addressing key components of facility design such as ventilation, fire detection, fire suppression, impact protection, and seismic and structural design;

WHEREAS, beyond the technical aspects of BESS installation and design, these building codes implement operational processes for the commissioning, maintenance, and decommissioning for BESS facilities;

WHEREAS, These processes require hazard mitigation plans, designate fire mitigation personnel, implement testing and maintenance processes, and verify that BESS installations are installed and operated according to approved plans and specifications;

WHEREAS, the building code also establishes minimum setback and development standards, ensuring that compliance with even the minimum standard still sets a high bar for safety, while allowing jurisdictions to implement additional development standards on an as-needed basis tailored to individual requirements;

WHEREAS, having evaluated those standards, the City/County has confirmed that compliance with governing regulations prepared by state agencies with expert input are adequate to address regulatory concerns over the potential impact issues of concern;

WHEREAS, the County/City intends to require compliance with these constantly evolving, state-of the art standards and does not intend to duplicate or add potentially inconsistent regulations.

NOW, THEREFORE, BE IT ORDAINED:

SECTION 1. Chapter X of the City Land Use Code is hereby amended to include add the following definitions:

A. Battery energy storage system: A facility designed and constructed for the purpose of storing and deploying electrical energy. Battery energy storage system uses may include associated electrical equipment including, but not limited to, generation interconnection lines (“gen-tie lines”), transformers, and cooling equipment as facility components.

B. Consumer scale battery energy storage systems. A facility designed and constructed for the purpose of storing electrical energy primarily for use upon the site which the facility occurs and as an accessory to a principle residential or commercial use, using battery technology and equipment.

C. Nationally recognized testing laboratory: An independent, nationally recognized association that researches and tests batteries and electrical components used in a battery energy storage system and provides a certification where proper use of the technology is safe.

D. Nationally recognized safety standard: A set of criteria or certifications that ensure the safety, quality, and reliability of a product or installation. These standards define specific requirements related to

design, manufacturing, performance, and usage. When a product or installation adheres to these standards, it demonstrates that it meets widely accepted safety benchmarks.

SECTION 2. A new Section X.X is added to the City Land Use Code is hereby added to read as follows:

A. Permits Required. A building permit and electrical permit shall be required for installation of all battery energy storage systems.

B. Fencing. Battery Energy Storage Systems that do not occur within an enclosed principle structure shall be fenced with a self-locking gate. Fence heights in excess of generally prescribed standards shall not apply if an increased fence height is required to adequately secure or obscure the facility.

C. Screening. Where screening requirements are established for a zone or based on proximity to an adjacent land use, Battery Energy Storage Systems shall be screened using the same methods and thresholds established for screening electrical substations.

D. Vegetation clearing. Areas within 10 feet of a battery energy storage system shall be cleared of vegetation and trees, including any overhanging limbs, or as prescribed by nationally recognized safety standards, whichever is greater.

E. Secondary Containment. Secondary spill containment and neutralization shall comply with IFC 1207.6.2, or other equivalent safety standard.

F. Height. Battery Energy Storage Systems shall comply with the building height limitations of the underlying zoning district for principle structures, except that aboveground generation interconnect ("gen-tie") lines shall be subject to the height standards for utility poles.

G. Setbacks. Battery energy storage systems shall comply with the setback requirements of the underlying zoning district for principle structures or any setbacks established in applicable nationally recognized safety standards, whichever is greater.

H. Lighting. Lighting of the battery energy storage systems shall be limited to that minimally required for safety and operational purposes and shall be shielded to prevent spillage to abutting properties.

I. Fire detection system. A fire detection system shall be designed and installed as required by WAC 51-54A-1207.5.4 and in accordance with NFPA 72, or other equivalent nationally recognized safety standard, where applicable.

J. Limits on sound levels. Operational phase exterior sound level limits are based on the Leq during the measurement interval, using a minimum measurement interval of one minute for a constant sound source, or a one-hour measurement for a non-continuous sound source, as measured from any property line of the lot the battery energy storage facility is located on.

1. For sound sources located within the [City or County], the exterior sound level limits as measured at the property line are as shown in the Table below:

K.	L. Zone classification of receiving land use

	M. Residential (dB(A)) (Leq)	N. Commercial (dB(A)) (Leq)	O. Industrial (dB(A)) (Leq)
P. Sound levels generated by Battery Energy Storage Systems	Q. 60	R. 65	S. 70

T. Safety.

1. Battery energy storage systems and equipment shall be listed by a Nationally Recognized Testing Laboratory to UL 9540 or an equivalent nationally recognized safety standard, with subcomponents meeting each of the following standards as applicable:

    a. Certified under the applicable electrical, building, and fire prevention codes as required by nationally recognized safety standards.

    b. Alternatively, field evaluation by a testing laboratory for compliance with UL 9540 (or other applicable nationally recognized safety standard) and applicable codes, regulations and safety standards may be used to meet system certification requirements.

2. Site Access. Site access points shall be maintained at all times, including reasonably timely snow removal if applicable, to ensure facility components are accessible by emergency personnel.

3. Battery energy storage systems, components, and associated ancillary equipment shall have required working space clearances, and electrical circuitry shall be within weatherproof enclosures marked with the environmental rating suitable for the type of exposure in compliance with nationally recognized safety standards. Battery energy storage systems shall be maintained in good working order and in accordance with industry standards.

U. Hearing Examiner Decision Criteria and Conditions

1. Where not a permitted use, the hearing examiner may approve or approve with conditions, a conditional use permit for a battery energy storage system when the proposal complies with the applicable requirements of chapters [conditional use permit criteria section] and this chapter. The hearing examiner may also consider whether the proposal is consistent with the following factors:

    a. The design, use, and operation of the battery energy facility complies with applicable guidelines, rules, regulations or statutes adopted by state law, or any agency or jurisdiction with authority;

    b. The conditional use will not be materially detrimental to uses or property in the immediate vicinity of the subject property;

    c. The proposal is consistent with the objectives and policies of the [natural environment, or equivalent] chapter of the Comprehensive Plan;

V. Additional Permit Submittal Requirements. In addition to other building permit submittal requirements, a building permit application for a battery energy storage system shall contain the following information:

1. Construction Documents. In addition to the other construction document submittal requirements of [plan submittal format code section], the applicant shall include in the permit application all information specified by WAC 51-54A-1207.1.3.

2. Commissioning Plan. The applicant shall submit a commissioning plan containing the information specified by WAC 51-54A-1207.2.1 to be referenced during commissioning, decommissioning, and/or abandonment activities associated with a battery energy storage system.:

    a. Decommissioning Bond. The owner and/or operator of the energy storage system, shall continuously maintain a fund or bond payable to the [jurisdiction], in a form approved by the [jurisdiction] for the removal of the battery energy storage system, in an amount sufficient to fund required decommissioning activities specified by the decommissioning plan, for the period of the life of the facility or until all requirements of the decommissioning plan have been satisfied. This fund may consist of a letter of credit from a Washington State licensed financial institution. All costs of the financial security shall be borne by the applicant.

3. The battery energy storage system shall be considered abandoned when it ceases to operate consistently or when permits issued for the facility have been suspended or revoked for [duration]. If the owner and/or operator fails to comply with decommissioning upon any abandonment, the [jurisdiction] may, at its discretion, enter the property and utilize the available bond and/or security for the removal of a battery energy storage system and restoration of the site in accordance with the decommissioning plan.

SECTION 3. Table X.X of the City Land Use Code is hereby amended to read as follows:

Land Use	Zone classification					
	Rural	Resource	Industrial	Commercial	Residential	All Other Zones
Battery Energy Storage System						
Consumer Scale Battery Energy Storage System						

P = Permitted; C = Conditional Use Permit; # = Refer to note

1. Battery energy storage systems are permitted in all zones as an accessory use to a utility facility, solar energy facility, wind energy facility, and electrical substation.

2. Permitted only as an accessory use.

WAC 51-54A-1207 Electrical energy storage systems.

1207.1 General. The provisions in this section are applicable to stationary and mobile electrical energy storage systems (ESS).

EXCEPTION: ESS in Group R-3 and R-4 occupancies not exceeding thresholds in Section 1207.11.4 shall comply with Section 1207.11 through 1207.11.9.

1207.1.1 Scope. ESS having capacities exceeding the values shown in Table 1207.1.1 shall comply with this section.

TABLE 1207.1.1
Energy Storage System (ESS) Threshold Quantities

Technology	Energy Capacity[a]
Capacitor ESS	3 kWh
Flow batteries[b]	20 kWh
Lead-acid batteries, all types	70 kWh[c]
Lithium-ion batteries	20 kWh
Sodium nickel chloride batteries	70 kWh
Nickel-cadmium batteries (Ni-Cd), Nickel Metal Hydride (Ni-MH), and Nickel Zinc (Ni-Zn) batteries	70 kWh
Nonelectrochemical ESS[d]	70 kWh
Other battery technologies	10 kWh
Other electrochemical ESS technologies	3 kWh
Zinc manganese dioxide batteries (Zn-MnO2)	70 kWh

For SI: 1 kilowatt-hour = 3.6 megajoules.

[a] Energy capacity is the total energy capable of being stored (nameplate rating), not the usable energy rating. For units rated in amp-hours, kWh shall equal rated voltage times amp-hour rating divided by 1,000.

[b] Shall include vanadium, zinc-bromine, polysulfide-bromide and other flowing electrolyte-type technologies.

[c] Fifty gallons of lead-acid battery electrolyte shall be considered equivalent to 70 kWh.

[d] Covers nonelectrochemical technologies such as flywheel and thermal ESS.

1207.1.1.1 Utilities and industrial applications. This section shall not apply to capacitors and capacitor equipment for electric utilities and industrial facilities used in applications such as flexible ac transmission (FACTS) devices, filter capacitor banks, power factor correction, and standalone capacitor banks for voltage correction and stabilization.

1207.1.1.2 Mobile ESS. Mobile ESS deployed at an electric utility substation or generation facility for 90 days or less shall not add to the threshold values in Table 1207.1.1 for the stationary ESS installation if both of the following conditions apply:

1. The mobile ESS complies with Section 1207.10.
2. The mobile ESS is only being used during periods in which the facility's stationary ESS is being tested, repaired, retrofitted, or replaced.

1207.1.3 Construction documents. The following information shall be provided with the permit application:

1. Location and layout diagram of the room or area in which the ESS is to be installed.
2. Details on the hourly fire-resistance ratings of assemblies enclosing the ESS.
3. The quantities and types of ESS to be installed.

4. Manufacturer's specifications, ratings, and documentation of the listings of each ESS and associated equipment.

5. Description of energy (battery) management systems and their operation.

6. Location and content of required signage.

7. Details on fire suppression, smoke or fire detection, thermal management, ventilation, exhaust, and deflagration venting systems, if provided.

8. Support arrangement associated with the installation, including any required seismic restraint.

9. A commissioning plan complying with Section 1207.2.1.

10. A decommissioning plan complying with Section 1207.2.3.

11. A fire safety and evacuation plan in accordance with Section 404.

1207.1.3.1 Utilities applicability. Plans and specifications associated with ESS owned and operated by electric utilities as a component of the electric grid that are considered critical infrastructure documents in accordance with the provisions of the North American Electric Reliability Corporation and other applicable governmental laws and regulations shall be made available to the fire code official for viewing based on the requirements of the applicable governmental laws and regulations.

1207.1.4 Hazard mitigation analysis. Failure modes and effects analysis (FMEA) or other *approved* hazard mitigation analysis shall be provided in accordance with Section 104.8.2 under any of the following conditions:

1. Where ESS technologies not specifically identified in Table 1207.1.1 are provided.

2. More than one ESS technology is provided in a single fire area where there is a potential for adverse interaction between technologies.

3. Where allowed as a basis for increasing maximum allowable quantities. See Section 1207.5.2.

4. Where flammable gases can be produced under abnormal conditions.

5. Where required by the fire code official to address a potential hazard with an ESS installation that is not addressed by existing requirements.

1207.1.4.1 Fault condition. The hazard mitigation analysis shall evaluate the consequences of the following failure modes. Only single failure modes shall be considered.

1. A thermal runaway condition in a single electrochemical ESS unit.

2. A mechanical failure of a nonelectrochemical ESS unit.

3. Failure of any battery (energy) management system or fire protection system within the ESS equipment that is not covered by the product listing failure mode effects analysis (FMEA).

4. Failure of any required protection system external to the ESS including, but not limited to, ventilation (HVAC), exhaust ventilation, smoke detection, fire detection, gas detection, or fire suppression system.

1207.1.4.2 Analysis approval. The fire code official is authorized to approve the hazardous mitigation analysis provided that the consequences of the hazard mitigation analysis demonstrate:

1. Fires will be contained within unoccupied ESS rooms or areas for the minimum duration of the fire-resistance-rated separations identified in Section 1207.7.4.

2. Fires involving the ESS will allow occupants or the general public to evacuate to a safe location.

1207.1.5 Large-scale fire test. Where required elsewhere in Section 1207, large-scale fire testing shall be conducted on a representative ESS in accordance with UL 9540A. The testing shall be conducted or witnessed and reported by an approved testing laboratory and show that a fire involving one ESS will not propagate to an adjacent ESS, and where installed within buildings, enclosed areas and walk-in units will be contained within the room, enclosed area or walk-in unit for the duration of the test. The test report shall be provided to the fire code official for review and approval in accordance with Section 104.8.2.

1207.1.6.1 Fire mitigation personnel. Where, in the opinion of the fire code official, it is essential for public safety that trained personnel be on-site to respond to possible ignition or re-ignition of a damaged ESS, the system owner, agent, or lessee shall dispatch within 15 minutes one or more fire mitigation personnel to the premise, as required and approved, at their expense. These personnel shall remain on duty continuously after the fire department leaves the premise until the damaged energy storage equipment is removed from the premises, or earlier if the fire code official indicates the public safety hazard has been abated.

1207.2.1 Commissioning. Commissioning of newly installed ESS and existing ESS that have been retrofitted, replaced, or previously decommissioned and are returning to service shall be conducted prior to the ESS being placed in service in accordance with a commissioning plan that has been approved prior to initiating commissioning. The commissioning plan shall include the following:

1. A narrative description of the activities that will be accomplished during each phase of commissioning, including the personnel intended to accomplish each of the activities.

2. A listing of the specific ESS and associated components, controls, and safety-related devices to be tested, a description of the tests to be performed, and the functions to be tested.

3. Conditions under which all testing will be performed, which are representative of the conditions during normal operation of the system.

4. Documentation of the owner's project requirements and the basis of design necessary to understand the installation and operation of the ESS.

5. Verification that required equipment and systems are installed in accordance with the approved plans and specifications.

6. Integrated testing for all fire and safety systems.

7. Testing for any required thermal management, ventilation, or exhaust systems associated with the ESS installation.

8. Preparation and delivery of operation and maintenance documentation.

9. Training of facility operating and maintenance staff.

10. Identification and documentation of the requirements for maintaining system performance to meet the original design intent during the operation phase.

11. Identification and documentation of personnel who are qualified to service, maintain and decommission the ESS, and respond to incidents involving the ESS, including documentation that such service has been contracted for.

12. A decommissioning plan for removing the ESS from service, and from the facility in which it is located. The plan shall include details on providing a safe, orderly shutdown of energy storage and safety systems with notification to the code officials prior to the actual decommissioning of the system. The decommissioning plan shall include contingencies for removing an intact operational ESS from service, and for removing an ESS from service that has been damaged by a fire or other event.

EXCEPTIONS:

Commissioning shall not be required for lead-acid and nickel-cadmium battery systems at facilities under the exclusive control of communications utilities that comply with NFPA 76 and operate at less than 50 VAC and 60 VDC. A decommissioning plan shall be provided and maintained where required by the fire code official.

1. Lead-acid and nickel-cadmium battery systems less than 50 VAC, 60 VDC that are in telecommunications facilities for installations of communications equipment under the exclusive control of communications utilities and located outdoors or in building spaces or walk-in units used exclusively for such installations that are in compliance with NFPA 76 shall be permitted to have a commissioning plan in compliance with recognized industry practices in lieu of complying with Section 1207.2.1.

2. Lead-acid and nickel-cadmium battery systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utilities, and located in building spaces or walk-in units used exclusively for such installations shall be permitted to have a commissioning plan in compliance with applicable governmental laws and regulations in lieu of developing a commissioning plan in accordance with Section 1207.2.1.

1207.3.1 Energy storage system listings. ESS shall be listed in accordance with UL 9540.

EXCEPTIONS:

1. Lead-acid and nickel-cadmium battery systems less than 50 VAC, 60 VDC in telecommunications facilities for installations of communications equipment under the exclusive control of communications utilities located outdoors or in building spaces used exclusively for such installations that are in compliance with NFPA 76.

2. Lead-acid and nickel-cadmium battery systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.

3. Lead-acid battery systems in uninterruptible power supplies listed and labeled in accordance with UL 1778 and utilized for standby power applications.

1207.3.7.1 Retrofitting lead acid and nickel cadmium. Changing out or retrofitting of lead-acid and nickel-cadmium batteries in the following applications shall be considered repairs where there is no increase in system size or energy capacity greater than 10 percent of the original design.

1. At facilities under the exclusive control of communications utilities that comply with NFPA 76 and operate at less than 50 VAC and 60 VDC.

2. Battery systems used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.

3. Batteries in uninterruptible power supplies listed and labeled in accordance with UL 1778 and used for standby applications only.

1207.5 Electrochemical ESS protection. The protection of electrochemical ESS shall be in accordance with Sections 1207.5.1 through 1207.5.8 where required by Sections 1207.7 through 1207.10.

TABLE 1207.5

Maximum Allowable Quantities of Electrochemical ESS

Technology	Maximum Allowable Quantities[a]
Storage Batteries	

Technology	Maximum Allowable Quantities[a]
Flow batteries[b]	600 kWh
Lead-acid, all types	Unlimited
Lithium-ion	600 kWh
Sodium nickel chloride	600 kWh
Nickel-cadmium (Ni-Cd), Nickel metal hydride (NI-MH) and nickel zinc (Ni-Zn)	Unlimited
Zinc manganese dioxide (Zn-MnO2)	Unlimited
Other battery technologies	200 kWh
Capacitors	
All types	20 kWh
Other Electrochemical ESS	
All types	20 kWh

For SI: 1 kilowatt hour = 3.6 megajoules.

[a] For electrochemical ESS units rated in amp-hours, kWh shall equal rated voltage times the amp-hour rating divided by 1,000.

[b] Shall include vanadium, zinc-bromine, polysulfide-bromide, and other flowing electrolyte-type technologies.

1207.5.1 Size and separation. Electrochemical ESS shall be segregated into groups not exceeding 50 kWh (180 mega-joules). Each group shall be separated a minimum of three feet (914 mm) from other groups and from walls in the storage room or area. The storage arrangements shall comply with Chapter 10.

EXCEPTIONS:

1. Lead-acid and nickel-cadmium battery systems in facilities under the exclusive control of communications utilities and operating at less than 50 VAC and 60 VDC in accordance with NFPA 76.
2. Lead-acid and nickel-cadmium systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.
3. Lead-acid battery systems in uninterruptible power supplies and labeled in accordance with UL 1778, utilized for standby power applications, and limited to not more than 10 percent of the floor area on the floor on which the ESS is located.
4. The fire code official is authorized to approve larger capacities or smaller separation distances based on large-scale fire testing complying with Section 1207.1.5.

1207.5.3 Elevation. Electrochemical ESS shall not be located in the following areas:

1. Where the floor is located more than 75 feet (22,860 mm) above the lowest level of fire department vehicle access.
2. Where the floor is located below the lowest level of exit discharge.

EXCEPTIONS:

1. Lead-acid and nickel-cadmium battery systems less than 50 VAC and 60 VDC installed in facilities under the exclusive control of communications utilities in accordance with NFPA 76.
2. Lead-acid and nickel-cadmium systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.
3. Lead-acid battery systems in uninterruptible power supplies and labeled in accordance with UL 1778, utilized for standby power applications, and limited to not more than 10 percent of the floor area on the floor on which the ESS is located.
4. Where approved, installations shall be permitted in underground vaults complying with NFPA 70, Article 450, Part III.
5. Where approved by the fire code official, installations shall be permitted on higher and lower floors.

1207.5.4 Fire detection. An approved automatic smoke detection system or radiant energy-sensing fire detection system complying with Section 907.2 shall be installed in rooms, indoor areas, and walk-in units containing electrochemical ESS. An approved radiant energy-sensing fire detection system shall be installed to protect open parking garage and rooftop installations. Alarm signals from detection systems

shall be transmitted to a central station, proprietary or remote station service in accordance with NFPA 72, or where approved to a constantly attended location.

EXCEPTION: Normally unoccupied, remote stand-alone telecommunications structures with a gross floor area of less than 1500 ft^2 (139 m^2) utilizing lead-acid or nickel-cadmium batteries shall not be required to have a fire detection system installed.

1207.5.4.1 System status. Lead-acid and nickel-cadmium battery systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations shall be allowed to use the process control system to monitor the smoke or radiant energy-sensing fire detectors required in Section 1207.5.4.

1207.5.5 Fire suppression systems. Rooms and areas within buildings and walk-in units containing electrochemical ESS shall be protected by an automatic fire suppression system designed and installed in accordance with one of the following:

1. Automatic sprinkler systems, designed and installed in accordance with Section 903.3.1.1 for ESS units (groups) with a maximum stored energy capacity of 50 kWh, as described in Section 1207.5.1, shall be designed with a minimum density of 0.3 gpm/ft^2 (1.14 L/min) based over the area of the room or 2,500 square-foot (232 m^2) design area, whichever is smaller, unless a lower density is approved based upon large-scale fire testing in accordance with Section 1207.1.5.
2. Automatic sprinkler system designed and installed in accordance with Section 903.3.1.1 for ESS units (groups) exceeding 50 kWh shall use a density based on large-scale fire testing complying with Section 1207.1.5.
3. The following alternative automatic fire-extinguishing systems designed and installed in accordance with Section 904, provided that the installation is approved by the fire code official based on large-scale fire testing complying with Section 1207.1.5:
   3.1. NFPA 12, Standard on Carbon Dioxide Extinguishing Systems.
   3.2. NFPA 15, Standard for Water Spray Fixed Systems for Fire Protection.
   3.3. NFPA 750, Standard on Water Mist Fire Protection Systems.
   3.4. NFPA 2001, Standard on Clean Agent Fire-Extinguishing Systems.
   3.5. NFPA 2010, Standard for Fixed Aerosol Fire-Extinguishing Systems.

EXCEPTIONS:
1. Fire suppression systems for lead-acid and nickel-cadmium battery systems at facilities under the exclusive control of communications utilities that operate at less than 50 VAC and 60 VDC shall be provided where required by NFPA 76.
2. Lead-acid and nickel-cadmium systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations, shall not be required to have a fire suppression system installed.
3. Lead-acid battery systems in uninterruptible power supplies listed and labeled in accordance with UL 1778, utilized for standby power applications, which is limited to not more than 10 percent of the floor area on the floor on which the ESS is located, shall not be required to have a fire suppression system.

1207.6 Electrochemical ESS technology-specific protection. Electrochemical ESS installations shall comply with the requirements of this section in accordance with the applicable requirements of Table 1207.6.

TABLE 1207.6
Electrochemical ESS Technology-Specific Requirements

Compliance Required[b]		Battery Technology							
Feature	Section	Lead -acid	Nickel cadmium (Ni-Cd), nickel metal hydride (Ni-MH) and nickel zinc (Ni-Zn)	Zinc manganese dioxide (ZnMnO2)	Lithium-ion	Flow	Sodium nickel chloride	Other ESS and Battery Technologies[b]	Capacitor ESS[b]
Exhaust ventilation	1207.6.1	Yes	Yes	Yes	No	Yes	No	Yes	Yes
Explosion control	1207.6.3	Yes[a]	Yes[a]	Yes	Yes	No	Yes	Yes	Yes
Safety caps	1207.6.4	Yes	Yes	Yes	No	No	No	Yes	Yes
Spill control and neutralization	1207.6.2	Yes[c]	Yes[c]	Yes[f]	No	Yes	No	Yes	Yes
Thermal runaway	1207.6.5	Yes[d]	Yes[d]	Yes[e]	Yes[e]	No	Yes	Yes[e]	Yes

[a] Not required for lead-acid and nickel-cadmium batteries at facilities under the exclusive control of communications utilities that comply with NFPA 76 and operate at less than 50 VAC and 60 VDC.
[b] Protection shall be provided unless documentation acceptable to the fire code official is provided in accordance with Section 104.8.2 that provides justification why the protection is not necessary based on the technology used.
[c] Applicable to vented-type (i.e., flooded) nickel-cadmium and lead-acid batteries.
[d] Not required for vented-type (i.e., flooded) batteries.
[e] The thermal runaway protection is permitted to be part of a battery management system that has been evaluated with the battery as part of the evaluation to UL 1973.
[f] Not required for batteries with jelled electrolyte.

1207.6.3 Explosion control. Where required by Table 1207.6 or elsewhere in this code, explosion control complying with Section 911 shall be provided for rooms, areas, ESS cabinets, or ESS walk-in units containing electrochemical ESS technologies.

EXCEPTIONS:
1. Where approved, explosion control is permitted to be waived by the fire code official based on large-scale fire testing complying with Section 1207.1.5 that demonstrates that flammable gases are not liberated from electrochemical ESS cells or modules.
2. Where approved, explosion control is permitted to be waived by the fire code official based on documentation provided in accordance with Section 104.8 that demonstrates that the electrochemical ESS technology to be used does not have the potential to release flammable gas concentrations in excess of 25 percent of the LFL anywhere in the room, area, walk-in unit or structure under thermal runaway, or other fault conditions.
3. Where approved, ESS cabinets that have no debris, shrapnel, or enclosure pieces ejected during large scale fire testing complying with Section 1207.1.5 shall be permitted in lieu of providing explosion control complying with Section 911.
4. Explosion control is not required for lead-acid and nickel-cadmium battery systems less than 50 VAC, 60 VDC in telecommunication facilities under the exclusive control of communications utilities located in building spaces or walk-in units used exclusively for such installations.
5. Explosion control is not required for lead-acid and nickel-cadmium systems used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility located in building spaces or walk-in units used exclusively for such installations.
6. Explosion control is not required for lead-acid battery systems in uninterruptible power supplies listed and labeled in accordance with UL 1778, utilized for standby power applications, and housed in a single cabinet in a single fire area in buildings or walk-in units.

1207.10.1 Charging and storage. For the purpose of Section 1207.10, charging and storage covers the operation where mobile ESS are charged and stored so they are ready for deployment to another site, and where they are charged and stored after a deployment.

EXCEPTION: Mobile ESS used to temporarily provide power to lead-acid and nickel-cadmium systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.

1207.10.2 Deployment. For the purpose of Section 1207.10, deployment covers operations where mobile ESS are located at a site other than the charging and storage site and are being used to provide power.

EXCEPTION: Mobile ESS used to temporarily provide power to lead-acid and nickel-cadmium systems that are used for dc power for control of substations and control or safe shutdown of generating stations under the exclusive control of the electric utility, and located outdoors or in building spaces used exclusively for such installations.

1207.11 ESS in Group R-3 and R-4 occupancies. ESS in Group R-3 and R-4 occupancies shall be in accordance with Sections 1207.11.1 through 1207.11.9.

EXCEPTIONS: 1. ESS listed and labeled in accordance with UL 9540 and marked "For use in residential dwelling units", where installed in accordance with the manufacturer's instructions and NFPA 70.

2. ESS rated less than 1 kWh (3.6 megajoules).

1207.11.1 Equipment listings. ESS shall be listed and labeled in accordance with UL 9540.

EXCEPTIONS: Not adopted.

1207.11.2.1 Spacing. Individual ESS units shall be separated from each other by at least three feet (914 mm) except where smaller separation distances are documented to be adequate based on large-scale fire testing complying with Section 1207.1.5.

1207.11.3 Location. ESS shall be installed only in the following locations:

1. Detached garages and detached accessory structures.

2. Attached garages separated from the dwelling unit living space and sleeping units in accordance with Section 406.3.2 of the International Building Code.

3. Outdoors or on the exterior side of exterior walls located a minimum of three feet (914 mm) from doors and windows directly entering the dwelling unit.

4. Enclosed utility closets, basements, storage or utility spaces within dwelling units and sleeping units with finished or noncombustible walls and ceilings. Walls and ceilings of unfinished wood-framed construction shall be provided with not less than 5/8 in. Type X gypsum wallboard.

ESS shall not be installed in sleeping rooms, or closets or spaces opening directly into sleeping rooms.

1207.11.4 Energy ratings. Individual ESS units shall have a maximum rating of 20 kWh. The aggregate rating of the ESS shall not exceed:

1. 40 kWh within utility closets, basements, and storage or utility spaces.

2. 80 kWh in attached or detached garages and detached accessory structures.

3. 80 kWh on exterior walls.

4. 80 kWh outdoors on the ground.

ESS installations exceeding the permitted individual or aggregate ratings shall be installed in accordance with Sections 1207.1 through 1207.9.

1207.11.6 Fire detection. ESS installed in Group R-3 and R-4 occupancies shall comply with the following:

1. Rooms and areas within dwelling units, sleeping units, basements and attached garages in which ESS are installed shall be protected by smoke alarms in accordance with Section 907.2.11.

2. A listed heat alarm shall be installed in locations where smoke alarms cannot be installed based on their listing.

1207.11.7 Protection from impact. ESS installed in a location subject to vehicle damage shall be protected by approved barriers. Appliances in garages shall also be installed in accordance with Section 304.3 of the International Mechanical Code.

1207.11.8 Ventilation. Indoor installations of ESS that include batteries that produce hydrogen or other flammable gases during charging shall be provided with exhaust ventilation in accordance with Section 304.5 of the International Mechanical Code.

1207.11.9 Toxic and highly toxic gas. Model code section not adopted.

1207.11.10 Electric vehicle use. The temporary use of an owner or occupant's electric-powered vehicle to power a dwelling unit or sleeping unit while parked in an attached or detached garage or outdoors shall comply with the vehicle manufacturer's instructions and NFPA 70.

[Statutory Authority: RCW 19.27.031 and 19.27.074. WSR 23-22-119, § 51-54A-1207, filed 10/31/23, effective 3/15/24; WSR 22-13-093, 23-12-107, and 23-20-027, § 51-54A-1207, filed 6/14/22, 6/7/23, and 9/25/23, effective 3/15/24.]



MSCE Energy Infrastructure Brief on the Electrical Grid

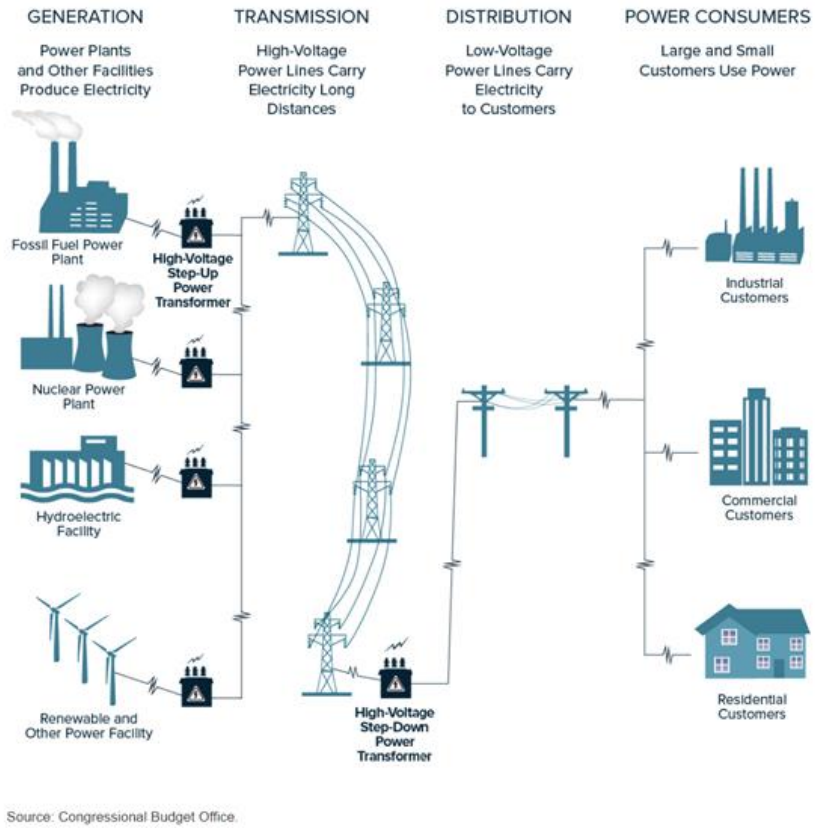
MSCE Energy Infrastructure Brief on
The Electrical Grid

Topics

- Introduction and Terminology
- Transmission Grid
- Distribution Grid
- Useful Websites

Introduction and Terminology

The electrical grid is illustrated below. It shows the four primary elements which are: (1) generation, (2) transmission, (3) distribution, and then (4) power consumers. As the electricity departs the power plants, the voltage is increased for transmission. Transmission lines move the electricity to the vicinity of users. The electricity voltage is then stepped down by transformers to enter a lower voltage set of power lines. These lower voltage lines constitute the distribution system which delivers electricity to specific customers.



Main Elements of the Electrical Grid

Source: Congressional Budget Office, "Enhancing the Security of the North American Electric Grid," March 2020

The US electrical grid consists of more than 7,000 power plants (the number of plants can be much larger…depends on which plants are included), nearly 160,000 miles of high-voltage transmission lines, and millions of low-voltage distribution lines and transformers, which serves about 145 million customers. An analogy between electricity and transportation, the transmission grid is equivalent to Interstate highways and the distribution system similar to lower volume rural roads.
[Energy Information Agency, https://www.eia.gov/todayinenergy/detail.php?id=27152]

Most of this Brief on the electrical grid will focus on transmission and distribution grids associated with the traditional "macrogrid." However, you should be aware that there is an additional grid descriptor which implies a different scale and function—a microgrid. Both definitions follow.

- **Macrogrid:** Typically referred to as the "grid." It connects homes, businesses, and other buildings to central power sources such solar, wind or fossil fuel power plants.
- **Microgrid:** A microgrid is typically a smaller grid with local control, which means it can disconnect from a large grid and operate autonomously.

There are numerous standards and regulations that govern reliability of the power sector. Here they are reduced to four and apply to the full system…not just the grid:

- Power generation and transmission capacity must be sufficient to meet **peak demand** for electricity.
- Power systems must have adequate flexibility to address **variability and uncertainty** in demand (load) and generation resources.
- Power systems must be able to maintain steady **frequency**.
  If frequency deviates significantly from 60 Hz, it could damage machines and electronics.
- Power systems must be able to maintain **voltage** within an acceptable range.

[Source: Maintaining Reliability in the Modern Power System, DOE, December 2016.
https://www.energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf]

Transmission Grid

The capacity needs in electricity markets has expanded transmission grids … in part due to a wide variety of generation. The transmission grid was originally built to interconnect neighboring utilities but now is used as a "superhighway." This can result in congestion which is a primary reason grid upgrades required.

How is the grid managed? There are two levels you should be aware of: (1) the interconnection of major grid areas and (2) balancing authorities. Discussions of both follow.

Interconnection Regions. The electrical grid is composed of two main networks, or interconnections which are largely electrically separate from other power regions, and three smaller interconnection networks for Texas, Quebec, and Alaska. Hawaii, Puerto Rico, other island territories, and portions of Canada operate separate grids. The network structure of the interconnections helps maintain the reliability of the grid by providing multiple routes for power to flow and allowing generators to supply electricity to numerous load centers (electricity users). This redundancy helps prevent transmission line or power plant failures from occurring. The three primary interconnection networks in the US are:

- The **Eastern** Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The **Western** Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The **Electric Reliability Council of Texas (ERCOT)** covers most, but not all, of Texas and consists of a single balancing authority. This system has limited connections with the Eastern and Western Interconnections largely to preclude federal oversight of ERCOT.

[After Energy Information Agency, https://www.eia.gov/todayinenergy/detail.php?id=27152]



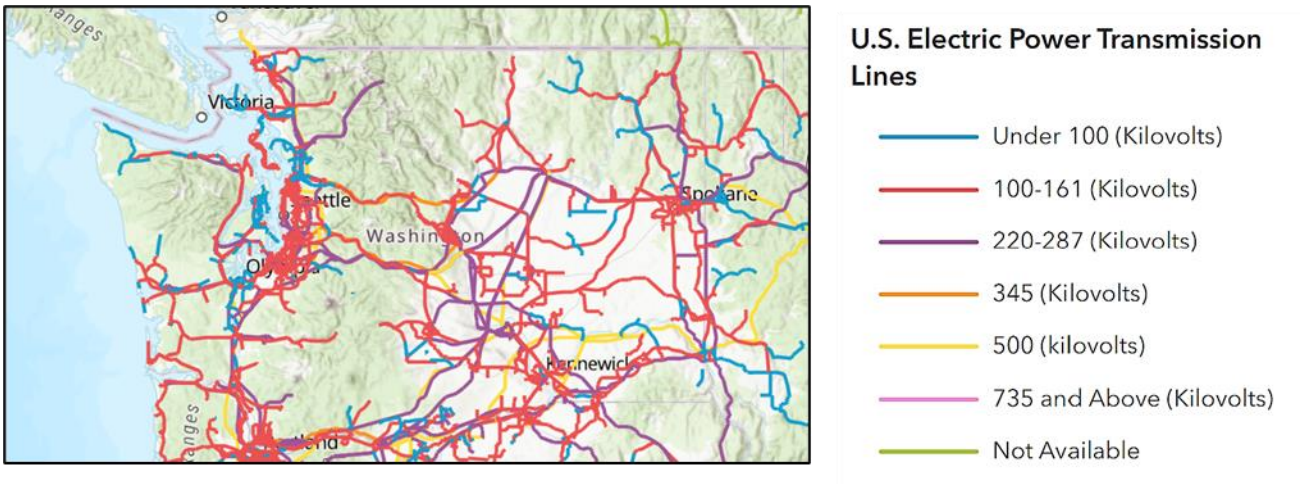
Interconnection Regions

Source: Congressional Budget Office, "Enhancing the Security of the North American Electric Grid," March 2020

Balancing Authorities. The regional grids describe the large-scale management and structure of the grid. The regional operation of the electric system is managed by **balancing authorities** whose primary job is to ensure that **electricity supply constantly matches power demand**. Most of the balancing authorities are electric utilities that fulfill balancing responsibilities for a specific part of the power system.

Transmission Voltages. The earliest transmission lines in the US (about 1896) were a maximum of 11 kV. Today transmission lines can have voltages up to 765 kV_{AC}. The importance of higher transmission voltages is straightforward—they allow longer transmission distances. This has increased in importance with the need to move large amounts of renewable generation to urban markets.

The voltage classes for transmission lines include both AC (voltages generally range between 230 to 765 kV) and DC (250 to 500 kV). The illustration below shows how the transmission grids are viewed as to voltages—in this case for Washington State. The maximum transmission line voltages for Washington are typically 500 kV but mostly less.



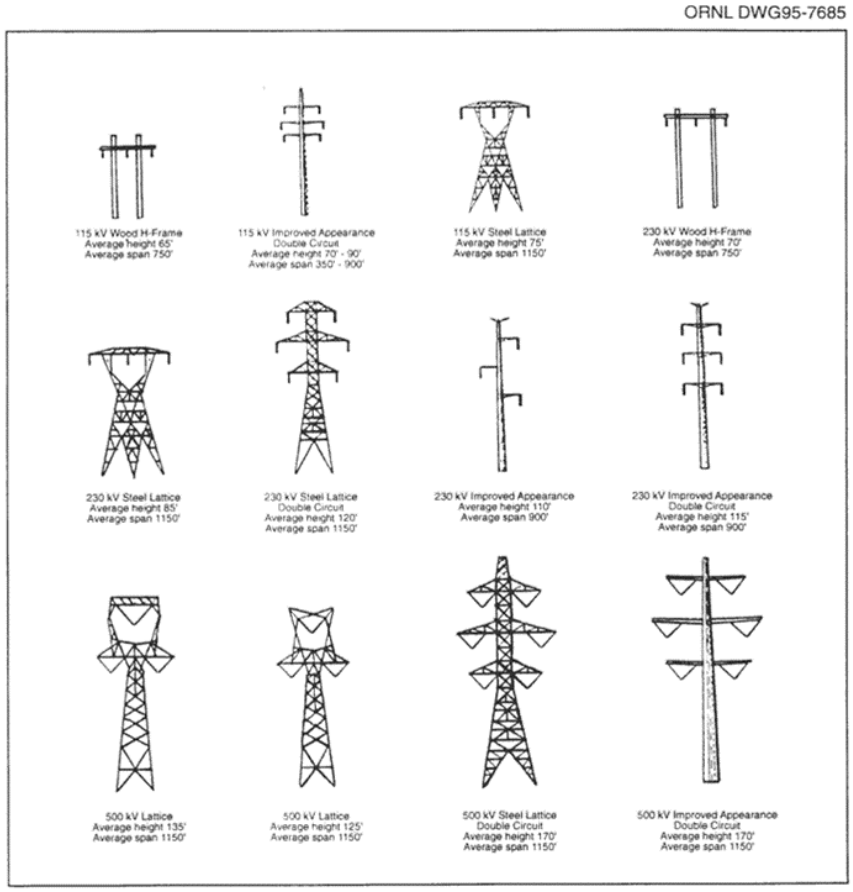
Source:[https://www.arcgis.com/home/webmap/viewer.html?useExisting=1&layers=d4090758322c4d32a4cd002ffaa0aa12]

Since transmission lines can be energized as either AC or DC, which is best? Major additions or changes to transmission lines can require extensive permitting, it may be best to use the existing type of delivery system—typically AC. However, DC lines have several positive features including narrower right-of-ways for its towers, two primary wires between towers instead of three for AC since it does not have phases, a 0 Hz frequency, and may be less expensive.

Transmission Grid Reliability. There are two types of electricity deviations which affect how a transmission grid operates … voltage and frequency … as noted earlier. Voltage deviations are typically associated with uncontrolled brownouts (excessively low voltage on the grid), and voltage surges (more likely to occur when electrical services are being restored). Second, for the US, the AC transmission line frequency operates at 60 Hz. Most other countries operate at 50 Hz. Regardless of the frequency used, transmission frequency is tightly controlled. If that is not the case, then generators or transmission lines can trip offline. What can cause this to happen?

(1) sudden supply or demand imbalances, and (2) short circuits (largely due to transmission line or equipment failures) or line faults (line faults are commonly caused by lightning).

Transmission Structures. Transmission lines can be supported by wood frames, steel lattices, single steel poles, or placed underground. Above ground heights as shown in the figure below range from 65 ft. up to 170 ft. As the height increases so does the span (distance between supports). Since most transmission lines are aluminum, temperatures must be considered to limit line sag.



A range of above ground transmission structures

Source: http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/fig005.gif

Distribution Grid

Handoff from the transmission grid to distribution lines occurs at a substation (refer to the figure on p.1 and the portion “Distribution” and “Power Consumers”). The substations take high voltages and step them down for the local distribution system. A small transformer near homes or apartments reduces the voltage further to 120 V/240 V.

Distribution lines typically have two broad descriptors: (1) distribution and secondary voltages; and (2) above or below ground placement. The focus for this section is above-ground installations, the most common and least expensive to construct.

Distribution Voltages. Distribution lines run from substations to homes and businesses and generally fall into four voltage classes:

- 4 to 5 kV
- 12 to 15 kV
- 20 to 25 kV
- 30 to 35 kV

For residential connections, which are called secondary circuits, the typical voltage from the distribution line is stepped down to 120/240 V. As for the larger electrical grid, the voltage for secondary circuits must be maintained within a range that does not damage customer equipment.

Distribution Structures (poles). Typically, wood power poles are used in the US for distribution. These can last up to 30 years (a range is typically 25 to 50 years). Some locations go with prestressed concrete poles which generally last > 50 years and better resist moisture, insects, and high winds. Some countries do not have easy access to wood poles and thus use concrete poles). Other material possibilities include steel and composites. The following figure shows a typical treated wood pole with transformer allowing connection with electrical loads.



Following major wind storms, such as hurricanes, the major outages are largely due to damage to the distribution system with the principal issues falling trees and branches impacting the lines.

Useful Websites

- DOE, “Transmission Division,” https://www.energy.gov/gdo/transmission-division
- Wikipedia, “North American Electric Reliability Corporation,” https://en.wikipedia.org/wiki/North_American_Electric_Reliability_Corporation
- UW MSCE Energy Infrastructure, https://www.energy-infrastructure.uw.edu/

ATTACHMENT 13

EXHIBIT H



Energy Storage System Location Study
For: Puget Sound Energy

Prepared by Tracy Rolstad (Technical Director)
Power Systems Consultants
Client Reference: Puget Sound Energy
PSC Reference: JU8426
Revision: Final (revised)
Date: 25 June 2021

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1. Introduction

Puget Sound Energy (PSE) engaged Power Systems Consultants (PSC) to perform a qualitative and quantitative analysis for siting a possible Energy Storage System (ESS) within the PSE electrical system. PSE filed a draft All-Source Request for Proposals (RFP) for peak capacity resources on May 4, 2020. Interconnection studies of an ESS onto a transmission system can result in the need for significant and costly network upgrades, depending upon interconnection location. This report serves as a starting point for proponents or bidders into the RFP as an aid to determine potential / lower risk locations (with respect to network upgrade costs) for interconnection of energy storage resources (and others) into PSE's transmission system.

The ESS is expected to perform in a manner consistent with the FERC defined Network Resource Interconnection Service. In general, this study is like a Feasibility Study in concept, but not necessarily in scope. Screening techniques examined the potential ESS capacity available at several Puget stations. Detailed analysis (like those completed for a Feasibility Study) was not performed.

The FERC definition of Network Resource Interconnection Service (below) can be used as a contextual guide in order to understand the purpose of this study.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Large Generating Facility (1) in a manner comparable to that in which Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an ISO or RTO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service Allows Interconnection Customer's Large Generating Facility to be designated as a Network Resource, up to the Large Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Large Generating Facility meets the requirements for Network Resource Interconnection Service and as a general matter, that such Large Generating Facility's interconnection is also studied with Transmission Provider's Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission Provider's Transmission System, consistent with Transmission Provider's reliability criteria and procedures. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Large Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

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1.1. Disclaimer

Note that all the information used for the study is available to any member of the public either directly (i.e., geo-location from the Department of Homeland Security) or via non-disclosure agreements with the Western Electricity Coordinating Council (for WECC base cases).

Some information (one-lines and station configurations) used (as an analytical aid) is based on FERC Form 715 submissions that pre-date (circa October 2001) the CEII classification of FERC 715 data. Station configurations and interconnections were confirmed with recent imagery.

The best possible data and analytical technique was used for this study; however, no warranty is offered by Power Systems Consultants for fitness of use of any data associated with this report or the contents of the report itself. PSC did not perform a purposeful review of base cases, maps, or one-lines for accuracy.

This study was completed outside of the OATT and is intended to broadly inform interested readers. It does not replace any OATT driven processes or documentation, nor is it intended to do so. The results in this document do not indicate that available transmission exists or that a station is suitable for interconnection from an official FERC LGIA process viewpoint.

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1.2. Energy Storage System (ESS) Discussion and Example

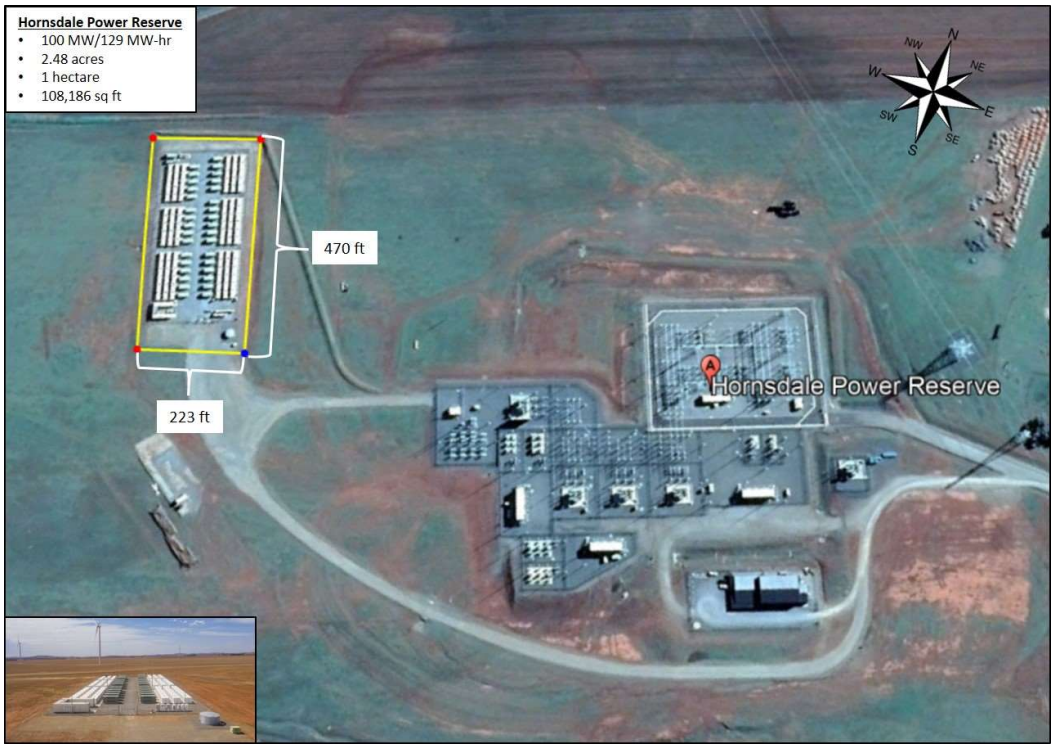
Modern utility scale ESS's store energy in the form of electro-chemical or mechanical energy, then convert that energy into electrical energy when appropriate, based on sophisticated control schemes.

Examples of electro-chemical storage include Lead Acid, Nickel-Cadmium, Lithium-Ion, and Molten Salt amongst others. Flow batteries are another type of electro-chemical battery, with Redox being an example. Mechanical energy storage examples include Flywheels, Pumped Hydro, and Compressed Air Energy Storage systems.

The study effort is agnostic to energy storage technology type and focuses primarily on the requirements of the ESS to interconnect on the PSE transmission system.

An example of a deployed Energy Storage System (located in South Australia) is shown in Figure 1.1. This is presently the world's largest ESS that uses Lithium-Ion batteries. The purpose of introducing this project is to give a sense of relative scale associated with a high energy capacity/high power ESS.

Figure 1.1 Hornsdale Power Reserve ESS



2. Methodology

Two methodologies were employed for this study. A qualitative and a quantitative method.

The qualitative method is a high-level review to determine potential for interconnection at the substation and to determine the potential to site an ESS in the area (PSE's property is not available for siting the ESS for this analysis). If a substation meets the evaluation metrics (detailed below) for the qualitative method, the locations will be further studied with the quantitative method.

The quantitative method is a high-level power flow analysis of the PSE transmission system, using official WECC databases to review the system performance with the addition of an ESS during charging and discharging conditions, for a multitude of system conditions and system contingencies.

These details of the qualitative and quantitative methods are discussed in the relevant section below.

2.1. Qualitative Method

Overhead imagery was utilized to determine the location of Puget's substations. This imagery was analysed in conjunction with WECC base cases and FERC 715 filings (pre-2001) that contain one-line drawings of the Puget system. We note that prior to October 2001 FERC 75 filings were available to the public. The stations were geo-located, mapped, locations were populated in the power flow-based cases, and then substations were created in the power flow base cases in order to support more detailed analysis using modelling and simulation tools.

2.1.1. Substation Interconnection Suitability

PSC examined the candidate substations to determine their suitability for expansion to accommodate interconnection of an ESS to the substation. This study assumes the ESS is sited off of PSE land in the area near the substation. Evaluation metrics are as below:

- Must interconnect to an existing Puget station
- Interconnects to PSE "native" network west of Cascades, no wheeling
- No radial or "return loop" transmission
- Above >100 kV point of interconnection (POI) per following details:
    - At least 4 lines for 115 kV candidate stations
    - Or non-radial 230 kV station
- Expansion space "in-the-gravel" in the station exists
- Development potential of existing station for interconnection is evident
    - Open space is desirable
    - Heavy residential presence is not desirable
    - Must pass the "Good Neighbor" test, which from an electric utility perspective has the following attributes:
        - Use of eminent domain proceedings is the absolute last resort with condemnation only used for those projects that are extremely mission critical and are supported politically.
        - The minimal number of landowners are impacted by a project and those landowners are justly compensated at prevailing rates.
        - Projects are developed with a focus on maximizing the use of existing "encumbered" properties.

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        - Land use should be reasonably consistent with its present use and the addition of electric utility infrastructure should be designed to be as unnoticeable as possible
        - Early involvement of the public in the development process is a must and the public should be encouraged to provide constructive input and alternative projects/locations
        - The public knows their neighbourhood best and can suggest minimum impact alternatives
        - Successful "Good Neighbor" projects leave the affected area better than it was before the project was executed.
- Identify substation configuration allows for additional breaker position
    - Ring bus, breaker and a half, double bus double breaker is preferred.
    - Main bus (with aux bus) has questionable reliability and could result in additional upgrades, up to rebuilding the substation to a different configuration.
    - Main bus (without aux bus) has poor reliability and is not suitable for interconnection of an ESS and would require substation upgrades, up to rebuilding the substation to a different configuration
        - An internal failure of a circuit breaker causes loss of entire station
- Identify existing unused breaker position (breaker not installed)
- Identify if the substation area allows for expansion
    - Examine available space inside substation fence
    - Examine available space outside substation fence
- If substation has 115 kV and 230 kV voltages, preference should be given to interconnect at the 115-kV side, unless interconnection at 230 kV results in substantial benefits.

2.1.2. ESS Siting Suitability

PSC examined how practical ESS siting near the substation is. This examination included:

- Land use and Zoning compatibility
    - Imagery analysis and general land usage was examined using tools such as Google Earth and Land Grid. These tools provide a means to develop a general qualitative sense of how favourable the location near a particular PSE station might be for an ESS project.
    - Highly residential areas, constraints for possible transmission rights-of-ways to the PSE station, schools, hospitals, and other notable land uses indicate that that specific PSE station was less desirable as a practical location to interconnect an ESS.
- Environmental Constraints
    - Overhead imagery analysis was performed in order to identify the possibility of complicated environmental constraints.
        - For example, the PSE Snoqualmie Falls station met the basic requirements of electrical connectivity but clearly it is not a desirable location for additional development. Thus, that station was not a candidate for further analysis.

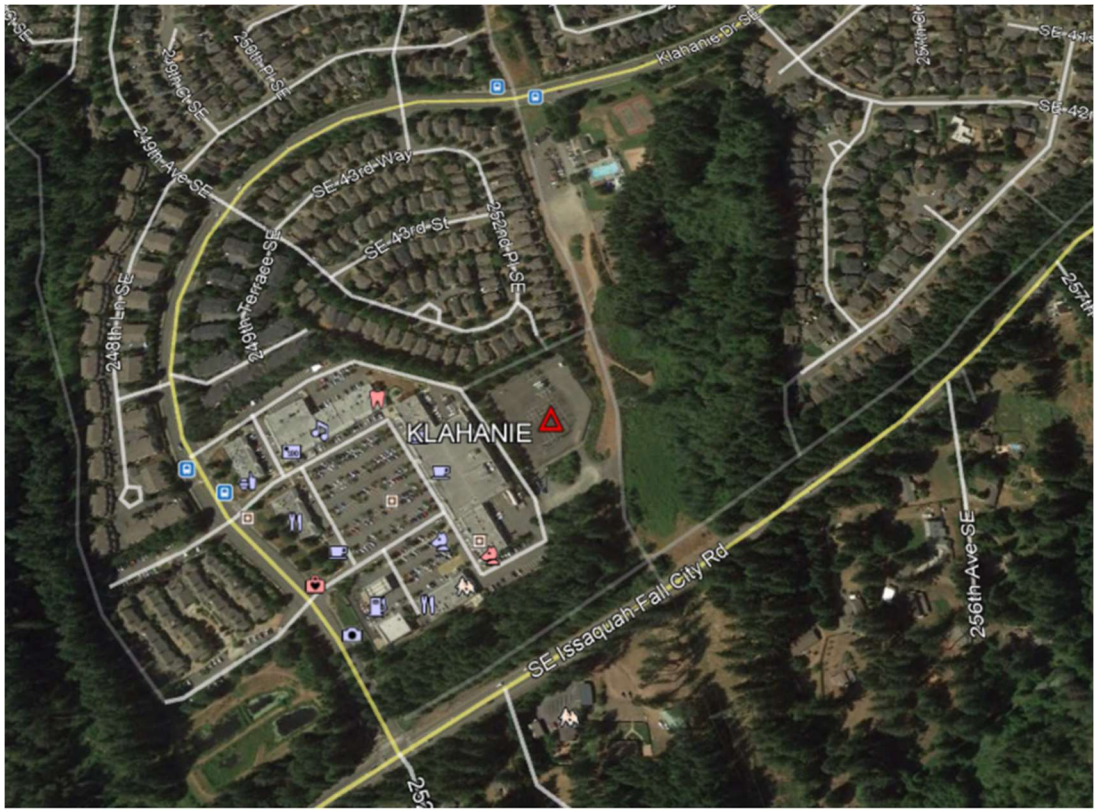
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2.2. Qualitative Method - Example

Two examples of qualitative review (i.e., go or no-go) of candidate stations are briefly discussed as follows.

The Klahanie station (Figure 2.1) would be characterized as a high "risk" or red station. The Klahanie station is not desirable for an ESS interconnection due to its lack of space, residential encroachment, and general lack of development potential.

Figure 2.1 Undesirable Station: Klahanie



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The Alderton station (Figure 2.2) is an example of a low "risk" (i.e., green station) that has desirable attributes associated with the station such as:

- Space for development in the immediate area
- Space in the station for expansion
- Fairly rural area that might be more easily support new rights-of-way, station expansion, or ESs siting

Figure 2.2 Desirable Station: Alderton



2.3. Quantitative Method

PSC used WECC power flow base cases to examine the PSE transmission system for the list of substations feasible for ESS interconnection. PSC used the PowerWorld (version 21) power flow ATC tool to perform analysis that approximates a "light-weight" generation interconnection feasibility screening study. This study is not a feasibility study under the OATT, but rather an informational screening that could aid an RFP respondent in determining where to queue for a detailed LGIA interconnection request. These POI's were examined as charging (load) and discharging (generating) resources.

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- Study Cases (WECC PowerWorld *.pwb power flow cases):
  - 2029-2030 Heavy Winter
    - Case used was 30HW1a1.pwb
  - 2030 Heavy Summer
    - Case used was 30HS1a.pwb
    - A 2029 HS case was originally used but then rejected due to an incomplete PSE transmission project that caused contingency performance issues (29HS1a1.pwb)
  - Off-peak load case (at consultants' discretion) which was the 2030 Light Spring case (30LSP1Sa.pwb)
- ESS studied as generation (discharging) and also as a load (charging)
  - ESS was studied one at a time
    - No groups or combinations of ESS's were studied
    - Only single ESS's were studied
- Only one interconnection per site location (either 115 kV or 230 kV, not both)
- Determine maximum ESS size at each location that results in acceptable system performance, for NERC TPL-001-4 PSE P0, P1 (N-1), and P6 (N-1-1) contingencies, while studying limited and sensitive neighbouring contingencies.

2.3.1. Quantitative Software Use and Approach

The results of the qualitative analysis and study were obtained using the "ATC" tool of PowerWorld Simulator. The details for implementing this in PowerWorld are briefly described as follows:

- Create an ALL WECC injection group of generators to dispatch against
  - The following metrics were used to select generators:
    - Pmax>10 MW
    - Pgen>10 MW
    - Pmin>0
  - ALL WECC injection group metrics (from 30HS case)
    - Number of generators is 2272
    - Total MW injection is ~191,294 MW
- Insert a single ESS (i.e. generator) and create an injection group for each station in Table 3.1
- Create an auto-inserted list of contingencies for Area 40
- Performed "Iterated Linear then Full Ctg" ATC analysis
  - Ignore elements with OTDFs < 3.0
  - Ignore elements with PTDFs<3.0
  - Report only:
    - 20 Transfer Limiters
    - 3 Limiters per ctg
    - 3 Limiters per element
- The results were manually inspected and those limiting elements and/or contingencies that were not relevant to the ESS were ignored for further analysis.
  - One may view this as machine aided learning to determine those contingencies and electrical system elements that are truly associated with electrical service to the ESS sites.
    - Many of these ignored elements/contingencies were 500 kV elements/contingencies with remedial action schemes or near their limits in the base case (for example various series capacitors associated with the California Oregon Intertie, etc).

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- The metrics associated with the quantitative analysis are noted below:
    - All elements with valid ratings were scanned for performance with the ATC tool for PO, P1, and P6 conditions of the NERC TPL-001-4 standard
        - Summer Emergency ratings were RATEA
        - Winter Emergency ratings were RATEC
        - Spring Emergency ratings were RATEG
    - P1 & P6 contingencies were those in the Northwest >100 kV
        - P1: 1135 out of 5081 contingencies were examined for detailed P1 performance
            - The smaller list of contingencies was selected using the Linear ATC tool which determined those contingencies sensitive to the PSE BESS sites.
        - P6: 1107 out of 144,453 contingencies were examined for detailed P6 performance
            - The smaller list was tested for performance using the Iterated Linear feature of the ATC tool. The larger amount was screened with the linear ATC tool.

3. Results

The results of the qualitative and quantitative analysis are listed below.

3.1. Qualitative Results

The results of the qualitative analysis and study were obtained in an iterative fashion. The list of candidate stations was then inspected both in PowerWorld Simulator and with overhead imagery to cull undesirable locations. The results follow:

- 382 total PSE initial stations (based on software results).
    - The 382-station count may not be a figure that exactly matches the number of stations that PSE has. This is due to the software requirement for a tapped line to be modeled with a bus, which might not be representative of an actual substation bus.
    - These 382 stations were geo-located.
- 36 PSE stations were kept for overhead imagery analysis based on the following:
    - Is 230 kV non-radial service.
    - Or is > 4 lines of 115 kV non-radial service.
    - And within PSE network
        - Determined from geo-location and bus ownership
    - Substation configuration metrics were not included in determining of the initial candidate stations.
- The 36 PSE stations were analysed and grouped by the following criteria for risk regarding ESS site location and interconnection:
    - Substation area analysis
    - Surrounding area analysis
    - Refined understanding of interconnection based on imagery analysis
- 12 stations (of the 36) were assigned “green”, for initial low risk ESS interconnection
- 8 stations (of the 36) were assigned “yellow”, for initial medium risk ESS interconnection
- 16 stations (of the 36) were assigned “red”, for high risk due to not meeting the initial qualitative screening metrics

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3.1.1. Candidate Stations

Table 3.1 lists the 20 PSE stations that were analyzed in detail. These stations were visually inspected with recent overhead imagery and are organized by color for low risk and medium risk substations. As previously stated, the substation configuration metrics were not used for the initial candidate stations and will be addressed later in the report. Substations that are of a main bus configuration are highlighted in red.

Table 3.1 Qualitative Results for Low Risk (Green) and Medium Risk (Yellow) Stations

Sub Name	Nominal kV Range	# of Lines	Bus Configuration (low & high voltage)	Zone
Alderton	115.0 (only)	7	Main & Aux	PIERCE
Berrydale	115.0 to 230.0	7	Main & Aux / Brk & half	S.KING
Christopher	115.0 (only)	6	Main Bus	S.KING
Frederickson	13.8 to 115.0	4	Main Bus	PIERCE
Fredonia	13.8 to 230.0 (115kV)	2	Main Bus	SKAGIT
Lake Tradition	115.0 (only)	8	Main Bus	N.KING
March Point	115.0 to 230.0	12	Main & Aux / Xfrm Term	SKAGIT
Midway	115.0 (only)	6	Main & Aux	S.KING
Saint Clair	115.0 to 230.0	7	Main & Aux / DB-DB	THURSTN
Sammamish	115.0 to 230.0	11	Main & Aux / Main & Aux	N.KING
Talbot Hill	115.0 to 230.0	14	Main & Aux / DB-DB	S.KING
Tono	115.0 (only)	4	Main & Aux	THURSTN
Bellingham	115.0 (only)	11	Brk & half	WHATCOM
Krain Corner	57.5 to 115	6	Main Bus	PIERCE
O'Brien	115.0 to 230.0	11	Main & Aux / Xfrm Term	S.KING
Portal Way	115.0 (only)	5	Main & Aux	WHATCOM
S. Bremerton	115.0 to 230.0	6	Main & Aux / Xfmr Term	KITSAP
Sedro Woolley	115.0 to 230.0	12	Main & Aux / Brk & half	SKAGIT
Starwood	115.0 (only)	4	Main Bus	S.KING
White River	115.0 to 230.0	12	Main & Aux / DB-DB	PIERCE

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Table 3.2 lists those stations that were deemed high risk and thus not selected for more detailed analysis.

Table 3.2 Qualitative Results for High Risk (Red) Stations

Sub Name	Nominal kV Range	# of Lines	Substation Type	Zone
ARCO C	115.0 (only)	4	Main Bus	WHATCOMI
BAKER SW	115.0 (only)	4	Main Bus	SKAGIT
BALDI	230.0 (only)	2	Tap	S.KING
CASCADE	34.5 to 230.0	3	Xfmr Term/Main Bus	KITTITAS
COTAGEBR	115.0 (only)	4	Main Bus	N.KING
ELECTHTS	57.5 to 115.0	5	Xfmr Term/Main Bus	PIERCE
HORSRNCH	230.0 (only)	3	Main Bus	N.KING
HRNCHTAP	230.0 (only)	2	Tap	N.KING
KLAHANIE	230.0 (only)	2	Tap	N.KING
LAKESIDE	115.0 (only)	7	Main Bus	N.KING
MINTFARM	13.8 to 230.0	1	Main (Gen Interconnection)	Portland Area
NOVELTYH	115.0 to 230.0	7	Main & Aux/Main Bus	N.KING
OLYMPA P	115.0 (only)	9	Main Bus	THURSTN
SHUFFLETON	115.0 (only)	4	Main & Aux	S.KING
SNOQ SW	2.0 to 115.0	5	Main Bus	N.KING
FREDONIA	13.8 to 115.0	4	Main Bus	SKAGIT

Note that there are two Fredonia stations, one serves a gas turbine power plant and the second serves local load. The “red” Fredonia station is the load serving station. Although these stations are “red” (or less desirable for ESS integration) they may be worthy of further review and analysis.

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3.2. Quantitative Results

3.2.1. Quantitative Results

Table 3.3, 3.4, and 3.5 lists the results from the quantitative analysis. The gen/load limit is equivalent to the discharge/charge limit for the ESS at the listed station for TPL-001-4 P0, P1, and P6 conditions (for the most limiting element). Units for the limits are MW. Note that we omit the negative sign for load since the sign is implicit in the definition of load.

Results shown in the tables indicate the ESS sizes for the different substations on an individual bases, meaning the potential size for a single ESS to be placed at any one of the locations listed. The results are not meant to indicate that the ESS sizes listed can be installed for all locations simultaneously.

BPA 500 kV contingencies (such as the Raver-Paul 500 kV line loss) were noted, but not considered as limiting contingencies since it is known that these contingencies have remedial action schemes associated with them. BPA has historically planned its system for P1 outages and has not necessarily planned (and built) its system to perform for P6 outages (without operator action).

A 2030 Light Spring case was examined to test performance under P0, P1, and P6 conditions to determine if there was any notable sensitivity to light spring conditions (in addition to the Heavy Summer and Heavy Winter cases).

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Table 3.3 P0 Quantitative Results

Quantitative Results - P0 Results in MW (Green shaded stations are low risk; yellow shaded stations are medium risk)								
Substation	**2030 Heavy Summer**		**2030 Heavy Winter**		**2030 Light Spring**		**Maximum ESS Size**	
	Generating	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**
Alderton	725	(790)	872	(823)	886	(998)	725	(790)
Berrydale	982	(248)	1077	(273)	1031	(569)	982	(248)
Christopher	751	(419)	1031	(648)	842	(622)	751	(419)
Frederickson	432	(316)	485	(440)	404	(466)	404	(316)
Fredonia	510	(803)	679	(873)	538	(878)	510	(803)
Lake Tradition	725	(534)	993	(701)	888	(837)	725	(534)
March Point	664	(367)	834	(367)	701	(412)	664	(367)
Midway	550	(263)	711	(333)	558	(368)	550	(263)
Saint Clair	520	(546)	756	(732)	810	(854)	520	(546)
Sammamish	409	(677)	517	(818)	546	(702)	409	(677)
Talbot Hill	754	(768)	935	(916)	834	(896)	754	(768)
Tono	755	(445)	567	(524)	548	(699)	548	(445)
Bellingham	695	(578)	1028	(894)	809	(1072)	695	(578)
Krain Corner	250	(222)	480	(351)	377	(308)	250	(222)
O'Brien	681	(554)	807	(694)	672	(627)	672	(554)
Portal Way	443	(565)	441	(772)	337	(740)	337	(565)
S. Bremerton	426	(328)	471	(341)	457	(420)	426	(328)
Sedro Woolley	779	(950)	935	(1134)	867	(995)	779	(950)
Starwood	573	(335)	693	(341)	637	(578)	573	(335)
White River	872	(802)	1029	(945)	955	(887)	872	(802)

Charging limits have a parenthetical ( ) used in order to clearly indicate that the number is a charging (i.e. load) value. The maximum ESS sized is determined by the maximum size that the ESS can operate for all cases. Therefore, the minimum value between the three seasonal cases determines the maximum ESS size for performance under P0 conditions.

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Table 3.4 P1 Quantitative Results

Quantitative Results – P1 Results in MW (Green shaded stations are low risk; yellow shaded stations are medium risk)								
Substation	**2030 Heavy Summer**		**2030 Heavy Winter**		**2030 Light Spring**		**Maximum ESS Size**	
	Generating	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**
Alderton	96	(366)	510	(581)	529	(655)	96	(366)
Berrydale	756	(167)	848	(181)	702	(437)	702	(167)
Christopher	552	(217)	758	(362)	613	(386)	552	(217)
Frederickson	135	(96)	308	(314)	266	(388)	135	(96)
Fredonia	110	(532)	161	(619)	124	(585)	110	(532)
Lake Tradition	518	(136)	811	(425)	664	(545)	518	(136)
March Point	272	(214)	555	(189)	485	(271)	272	(189)
Midway	432	(164)	530	(207)	446	(262)	432	(164)
Saint Clair	45	(254)	239	(423)	311	(685)	45	(254)
Sammamish	323	(99)	411	(370)	495	(425)	323	(99)
Talbot Hill	552	(242)	741	(459)	688	(590)	552	(242)
Tono	437	(85)	275	(374)	282	(543)	275	(85)
Bellingham	322	(109)	545	(452)	384	(656)	322	(109)
Krain Corner	136	(34)	250	(88)	188	(112)	136	(34)
O'Brien	535	(258)	634	(276)	559	(401)	535	(258)
Portal Way	105	(446)	392	(628)	284	(614)	105	(446)
S. Bremerton	313	(89)	301	(27)	375	(185)	301	(27)
Sedro Woolley	287	(589)	577	(715)	450	(700)	287	(589)
Starwood	373	(181)	545	(250)	459	(299)	373	(181)
White River	583	(379)	838	(434)	715	(592)	583	(379)

Charging limits have a parenthetical ( ) used in order to clearly indicate that the number is a charging (i.e. load) value. The maximum ESS sized is determined by the maximum size that the ESS can operate for all cases. Therefore, the minimum value between the three seasonal cases determines the maximum ESS size for performance under P1 conditions.

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Table 3.5 P6 Quantitative Results

Quantitative Results – P6 Results in MW (Green shaded stations are low risk; yellow shaded stations are medium risk)								
Substation	**2030 Heavy Summer**		**2030 Heavy Winter**		**2030 Light Spring**		**Maximum ESS Size**	
	Generating	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**	**Generating**	**Charging**
Alderton	134*	(76*)	448	(205)	324	(290)	134*	(76*)
Berrydale	515*	(52*)	847	(90)	707	(336)	515*	(52*)
Christopher	484*	(57*)	756	(337)	610	(386)	484*	(57*)
Frederickson	99*	(86*)	275	(284)	222	(389)	99*	(86*)
Fredonia	9*	(378)	101	(421)	69	(479)	9*	(378)
Lake Tradition	521*	(44*)	805	(387)	664	(545)	521*	(44*)
March Point	9*	(54)	201	(62)	172	(78)	9*	(54)
Midway	428*	(56*)	512	(121)	444	(218)	428*	(56*)
Saint Clair	39*	(412)	147	(528)	159	(633)	39*	(412)
Sammamish	323	(46*)	411	(370)	495	(445)	323	(46*)
Talbot Hill	450*	(48*)	622	(359)	833	(896)	450*	(48*)
Tono	592	(122*)	267	(339)	548	(698)	267	(122*)
Bellingham	10*	(108)	418	(67)	382	(657)	10*	(67)
Krain Corner	136*	(34*)	178	(4*)	188	(112)	136*	(4*)
O'Brien	520*	(54*)	225	(176*)	560	(521)	225	(54)
Portal Way	11*	(446)	185	(362)	298	(614)	11*	(362)
S. Bremerton	314	(89*)	79	(23*)	375	(185)	79	(23*)
Sedro Woolley	48*	(590)	519	(622)	447	(755)	48*	(590)
Starwood	370*	(13*)	240	(107*)	460	(311)	240	(13*)
White River	365*	(13*)	382	(121*)	714	(750)	365*	(13*)

Charging limits have a parenthetical ( ) used in order to clearly indicate that the number is a charging (i.e. load) value. The maximum ESS sized is determined by the maximum size that the ESS can operate for all cases. Therefore, the minimum value between the three seasonal cases determines the maximum ESS size for performance under P6 conditions. Those limits with an asterisk (*) indicate that a pre-existing limit was ignored, and the first non-zero ATC transfer limit was recorded for the ESS charging and discharging contingency-based limit.

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4. Analysis

A review of Table 3.2, Table 3.3, and Table 3.4, indicate to the user the following:

- A single ESS performs for both discharging (generator) and charging (load) depending upon the substation location
  - Between 248 MW – 802 MW under P0 conditions
  - Between 45 MW – 434 MW for P1 conditions
  - Between 9 MW – 122 MW for P6 conditions
- Summer ratings can be most limiting and generally (but not always) summer may be the defining season for limiting an ESS.
  - This is due to limits being thermally based and higher summer temperatures causing de-rating of thermally limited equipment.
- Pre-existing conditions exist that should be examined in greater detail if any of these ESS locations are considered for interconnection.
- Limitations exist for P6 summer operations
  - Note that for ESS limits indicated with an asterisk (*) in the tables indicate there pre-existing P6 issues may exist.
- Some P6 contingencies may, surprisingly, perform better than P1 contingencies
  - The reasons for this are complex but, in many cases, the P1 limiting element is removed from service by the P6 contingency and thus a higher limiting element is relevant.

Table 4.1 shows the results for each substation on a contingency category bases, and also shows the maximum size for the ESS when generating or charging. Similarly, to before, the maximum size is the minimum value across the three contingency categories (i.e. P0, P1, and P6).

Further, the table shows the Total Maximum size of the ESS. The Total Maximum size is the minimum value (absolute) between the generating and charging values and represents the maximum size of the ESS that allows for unconstrained use during varying seasonal load conditions, varying operating conditions, and varying contingencies. The Total Maximum size is the value used to show the potential ESS size that might be achieved for NRIS while limiting the risk of additional costly network upgrades (transmission line rebuilds / reconductoring, etc.) outside of those required for interconnection to the substation.

The Operational Agreements determined with the developer could increase the Total Maximum size beyond the P6 charging limitations of the ESS listed in the table below.

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Table 4.1 Combined Quantitative Results

Substation	Substation Type	P0 Results		P1 Results		P6 Results		Maximum ESS		Total Maximum
		Generating	Charging	Generating	Charging	Generating	Charging	Generating	Charging	
Alderton	Main & Aux	725	(790)	96	(366)	134*	(76*)	96	(76*)	76*
Berrydale	Main & Aux	982	(248)	702	(167)	515*	(52*)	515*	(52*)	52*
Christopher	Main Bus	751	(419)	552	(217)	484*	(57*)	484*	(57*)	57*
Frederickson	Main Bus	404	(316)	135	(96)	99*	(86*)	99*	(86*)	86*
Fredonia	Main Bus	510	(803)	110	(532)	9*	(378)	9*	(378)	9*
Lake Tradition	Main Bus	725	(534)	518	(136)	521*	(44*)	518	(44*)	44*
March Point	Main & Aux	664	(367)	272	(189)	9*	(54)	9*	(54)	9*
Midway	Main & Aux	550	(263)	432	(164)	428*	(56*)	428*	(56*)	56*
Saint Clair	Main & Aux	520	(546)	45	(254)	39*	(412)	39*	(254)	39*
Sammamish	Main & Aux	409	(677)	323	(99)	323	(46*)	323	(46*)	46*
Talbot Hill	Main & Aux	754	(768)	552	(242)	450*	(48*)	450*	(48*)	48*
Tono	Main & Aux	548	(445)	275	(85)	267	(122*)	267	(85)	85
Bellingham	Brk & half	695	(578)	322	(109)	10*	(67)	10*	(67)	10*
Krain Corner	Main Bus	250	(222)	136	(34)	136*	(4*)	136*	(4*)	4*
O'Brien	Main & Aux	672	(554)	535	(258)	225	(54*)	225	(54*)	54*
Portal Way	Main & Aux	337	(565)	105	(446)	11*	(362)	11*	(362)	11*
S. Bremerton	Main & Aux	426	(328)	301	(27)	79	(23*)	79	(23*)	23*
Sedro Woolley	Main & Aux	779	(950)	287	(589)	48*	(590)	48*	(589)	48*
Starwood	Main Bus	573	(335)	373	(181)	240	(13*)	240	(13*)	13*
White River	Main & Aux	872	(802)	583	(379)	365*	(13*)	365*	(13)	13*

Those limits with an asterisk (*) indicate that a pre-existing limit was ignored, and the first non-zero ATC transfer limit was recorded for the ESS charging and discharging contingency-based limit. As stated above, the Operational Agreements determined with the developer could increase the Total Maximum size beyond the P6 charging limitations of the ESS.

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Table 4.2 shows a summary of the results for this effort. The table provides the reader with a convenient listing of the Total Maximum ESS output and the location of the electrical point of interconnection studied, as well as substation type, and operating voltage.

Table 4.2 Location Summary with Maximum ESS Results

Substation	Substation Type	Voltage (kV)	Location		Total Maximum ESS (MW)
			Latitude	Longitude	
Alderton	Main & Aux	115	47.15344	-122.2365	76
Berrydale	Main & Aux	115	47.37803	-122.1311	52
Christopher	Main Bus	115	47.33708	-122.2393	57
Frederickson	Main Bus	115	47.08061	-122.3647	86
Fredonia	Main Bus	115	48.45461	-122.4371	9
Lake Tradition	Main Bus	115	47.53069	-122.0117	44
March Point	Main & Aux	115	48.45714	-122.5625	9
Midway	Main & Aux	115	47.40239	-122.2944	56
Saint Clair	Main & Aux	115	47.03511	-122.7356	39
Sammamish	Main & Aux	115	47.68558	-122.1499	46
Talbot Hill	Main & Aux	115	47.46864	-122.191	48
Tono	Main & Aux	115	46.75539	-122.8775	85
Bellingham	Brk & half	115	48.75939	-122.4604	10
Krain Corner	Main Bus	115	47.23511	-121.9855	4
O'Brien	Main & Aux	115	47.40317	-122.2432	54
Portal Way	Main & Aux	115	48.90361	-122.63	11
S. Bremerton	Main & Aux	115	47.53764	-122.6914	23
Sedro Woolley	Main & Aux	115	48.50458	-122.204	48
Starwood	Main Bus	115	47.29039	-122.3623	13
White River	Main & Aux	115	47.239	-122.2096	13

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As discussed previously, the main bus substation configuration (without an aux bus) has questionable reliability and interconnecting at a main bus substation has the potential to result in the need for high network costs to rebuild the substation. The substations that are configured with just a main bus (with no aux bus) were removed from the results to create the final results table as shown in Table 4.3. The table provides the reader with a convenient listing of the Maximum ESS output and the location of the electrical point of interconnection studied, as well as substation type, and operating voltage.

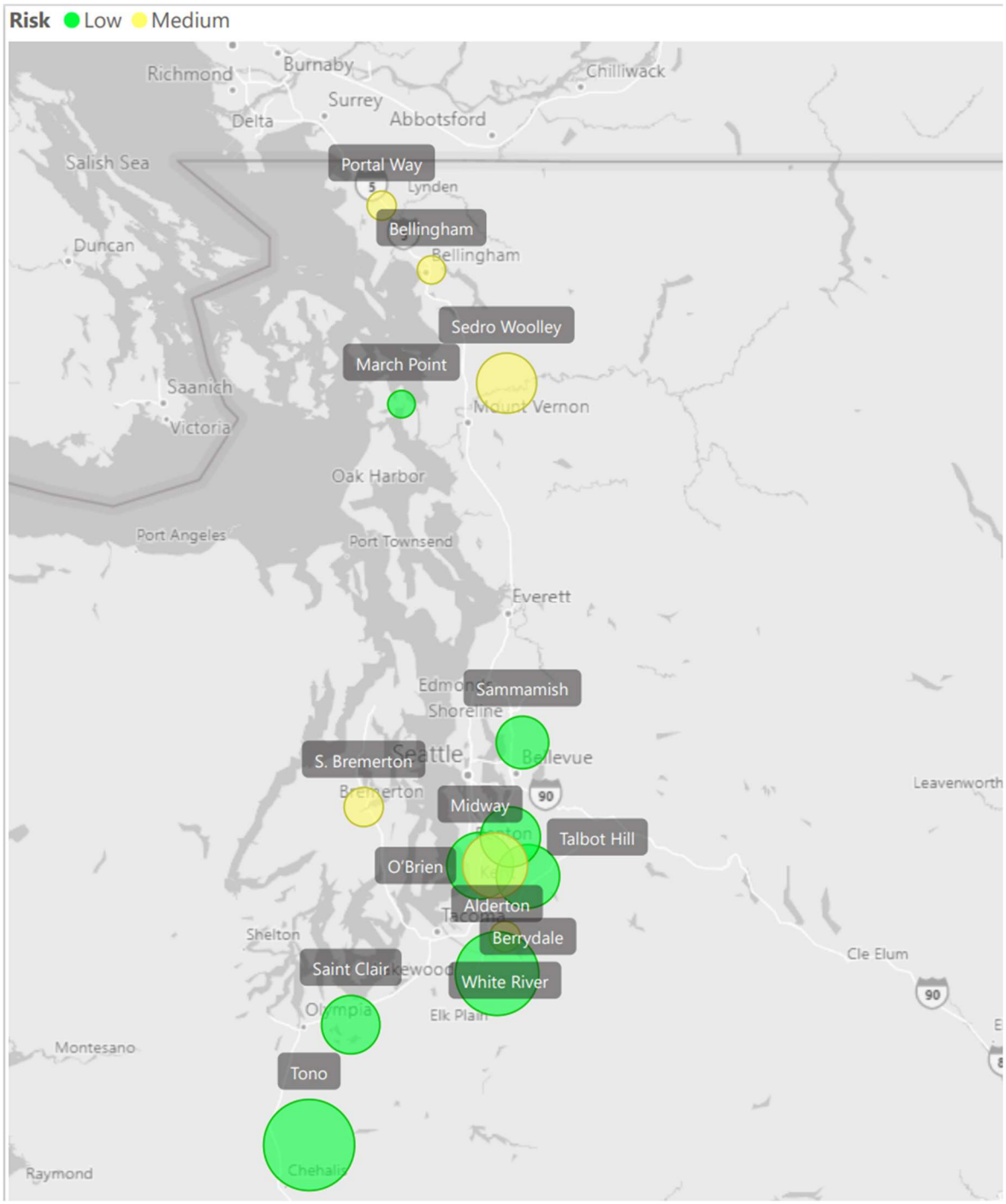
Table 4.3 Final Results Table

Substation	Substation Type	Voltage (kV)	Location		Total Maximum ESS (MW)
			Latitude	Longitude	
Alderton	Main & Aux	115	47.15344	-122.2365	76
Berrydale	Main & Aux	115	47.37803	-122.1311	52
March Point	Main & Aux	115	48.45714	-122.5625	9
Midway	Main & Aux	115	47.40239	-122.2944	56
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Sedro Woolley	Main & Aux	115	48.50458	-122.204	48
White River	Main & Aux	115	47.239	-122.2096	13

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Figure 4.1 gives an approximate location of the substations with low and medium risk for interconnection. The figure shows that there are many opportunities throughout the native PSE system for interconnecting an ESS.

Figure 4.1 Location of Selected Stations



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5. Conclusions and Recommendations

PSC believes that opportunities exist for Puget Sound Energy to install Energy Storage Systems in several stations without undue impact (or required network upgrades) to the surrounding electrical transmission system. We base this conclusion of performance under P6 outages during heavy summer and winter peak load conditions, as required for Network Resource Interconnection Service for use as a capacity resource on PSE's transmission system.

As previously stated, the results of this effort are to be used to help guide proponents to locations (with approximate capacities) that might offer success for interconnection of an ESS for NRIS with limited network upgrades. The formal LGIA process, as detailed under the Puget Sound Energy FERC Open Access Transmission Tariff (OATT), will define required system interconnection upgrades and any potential network upgrades as a result of the more detailed studies (power flow and transient), impacts of projects already in the interconnection que, affected neighbouring transmission providers, and short circuit analysis.

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CITY OF AUBURN WASHINGTON

AGENDA BILL APPROVAL FORM

Agenda Subject:
Co-Living Housing Code Update (Goode)
Community Development Department will present on the implementation of RCW 36.70A.535 for co-living housing. Co-living housing means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building. This text amendment to Title 18 ACC will allow for the new use to be permissible in the R-3, R-4, R-NM, DUC, C-2, C-AG, and M-1 Zones and provides details on development standards for the new use.

Meeting Date:
December 2, 2025

Department:
Community Development

Attachments:
Planning Commission Staff Report , Exhibit 1 PowerPoint Presentation, Exhibit 2 Co-Living Housing Text Amendment, Exhibit 3 Public Comments, Exhibit 4 Commerce Co-Living Guidance

Budget Impact:
N/A

Administrative Recommendation:
Planning Commission to recommend approval of the Co-Living Housing Code update.

Background for Motion:

Background Summary:
See attached Staff Report

Councilmember:

Staff: Jason Krum

PLANNING COMMISSION STAFF REPORT

AGENDA SUBJECT/TITLE:
Co-living Code Update

CITY FILE NO(s).:
ZOA25-0003

APPLICANT/AGENT/OWNERS:
City of Auburn

REQUEST:
Planning Commission to hold a public hearing, deliberate, and take action on the revised proposed regulations for co-living housing to comply with the state requirements.

LOCATION:
City-wide

NOTIFICATION:
The Notice of Public Hearing was published in the Seattle Times and posted on the City's Land Use Notice webpage and physically at City Hall and City Hall Annex on October 7, 2025 and re-noticed on November 21, 2025.

HEARING DATE:
December 2, 2025

SEPA STATUS:
A SEPA Environmental Checklist – Non-Project Action was submitted and reviewed with the application. A DNS using the Optional process was issued on October 7, 2025, with the appeal period expiring on October 17, 2025.

STAFF:
Owen Goode, Planner II, Dept. of Community Development

STAFF RECOMMENDATION:
Text amendment amending Title 18 "Zoning", Chapters 18.04 and 18.07, and Sections 18.02.067, 18.23.030, 18.31.161, and 18.52.020 to comply with RCW 36.70A.535: Co-living housing. Co-living housing is defined as "residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building". To comply with the RCW, planning staff proposes to create a new section, Section 18.31.161 "Supplemental standards for co-living housing"; to amend Section 18.02.067 "Units allowed per lot"; amend Chapter 18.04 "Definitions"; amend Chapter 18.07 "Residential Zones"; amend Section 18.23.030 "Uses" for Commercial and Industrial Zones; and amend Section 18.52.020 "Number of off-street parking spaces required".

SUMMARY OF CODE CHANGES:

DEFINITIONS

Definitions in Chapter 18.04 ACC are proposed to be added or revised to address the new Co-living housing.

- Co-living housing – new definition ACC 18.04.239
- Sleeping unit – new definition ACC 18.04.340

CO-LIVING HOUSING

Revise ACC 18.02.067 Units allowed per lot
ACC 18.02.067(F) is revised to add clarification on the density for co-living housing. For the purpose of calculating density for co-living housing, one sleeping unit shall equate to 0.25 dwelling units. For example, a co-living housing development with 16 sleeping units would equate to 4 dwelling units.

Revise ACC 18.23.030 Commercial Uses
ACC Table 18.23.030 of the commercial use table is revised to allow co-living housing within the C-2, C-AG, and M-1 Zones. These zones allow for mixed-use development to contain 6 or more multifamily units as part of the mixed-use development. Revised Code of Washington (RCW) 36.70A.535 prohibits cities from requiring other uses to be provided when co-living housing is proposed which is reflected in the table revision as well. When co-living housing is provided in the above permissible commercial zones, the City of Auburn shall not require a mixed-use component within the project.

Revise Chapter 18.07 Residential Zones
ACC Table 18.07.020 Uses is revised to allow co-living housing within the DUC, R-3, R-4, and R-NM Zone. Cities are required to allow co-living housing as a permitted use on any lot that allows at least six multifamily residential units. The residential zones listed allow for multifamily development, listed as apartments (7 units or more) which means those zones shall also allow for co-living housing to be permitted.

Add New Section ACC 18.31.161 Supplemental standards for co-living housing
This section is added to provide additional standards for how co-living housing is provided. Standards in this section include exemptions for co-living housing that cannot be applied such as room dimensional standards, requiring a mix of unit sizes, requiring a mixed-use component, requiring off-street parking within one-half mile walking distance of a major transit stop, requiring more than 0.25 parking spaces per sleeping unit, calculating density that exceeds 0.25 dwelling units per sleeping unit, and applying any other standards that are more restrictive than what is already applied to typical multifamily developments.

Revise ACC 18.52.020 Number of off-street parking spaces required
The number of off-street parking spaces requirements is revised to reflect a 0.25 parking spaces per sleeping unit for co-living housing within ACC Table 18.52.020.

FINDINGS OF FACT:

Background Summary:

1. Washington State is experiencing a housing affordability crisis and co-living housing is a type of housing that can provide rental homes affordable to people with moderate to low incomes without requiring any public funding, and rents in newly constructed, market-rate co-living housing in the Puget Sound region can be affordable to people with incomes as low as 50 percent of area median income.

2. Co-living housing is a residential development with sleeping units that are independently rented and provide living and sleeping space, in which residents share kitchen facilities with residents of other units in the building.

3. Per the RCW 36.70A.535 cities planning under the Growth Management Act (GMA) must adopt development regulations allowing co-living as a permitted use on any lot located within an urban growth area.

4. Per RCW 36.70A.535 zones that allow at least six multifamily residential units, including on a lot zoned for mixed-use development must allow co-living housing as a permissible use.

5. Requirements for co-living take effect December 31, 2025. By this date, subject cities and counties must adopt or amend co-living housing standards, consistent with RCW 36.70A.535, by ordinance and incorporate co-living housing into their development regulations, zoning regulations, and other official controls. If updates to bring co-living standards into alignment with statutory requirements are not completed by this date, the requirements of RCW 36.70A.535 will “supersede, preempt, and invalidate any conflicting local development regulations.”

6. Per RCW 36.70A.535(2), cities may not require co-living housing proposals to contain room dimensional standards, require a mix of unit sizes or number of bedrooms, or require other uses within project.

7. Per RCW 36.70A.535(3), cities may not require co-living housing to provide off-street parking when the project site is within one-half mile walking distance of a major transit stop or provide more than 0.25 off-street parking spaces per sleeping unit.

8. Per RCW 36.70A.535 cities may not require through development regulations any standards for co-living housing that are more restrictive than those that are required for other types of multifamily residential uses in the same zone. A city or county may only require a review, notice, or public meeting for co-living housing that is required for other types of residential uses in the same location, unless otherwise required by state law including, but not limited to, shoreline regulations under Chapter 90.58 RCW. Cities may not exclude co-living housing from participating in affordable housing incentive programs under RCW 36.70A.540, may not treat a sleeping unit in co-living housing as more than one-quarter of a dwelling unit for purposes of calculating dwelling unit density, and may

not treat a sleeping unit in co-living housing as more than one-half of a dwelling unit for purposes of calculating fees for sewer connections.

9. The sewer connection fee in the City of Auburn is a flat fee for each new connection to the sanitary sewer main and is not based on dwelling units in the 2025 Fee Schedule.

10. Per ACC 18.68.030(B) A "Zoning Text Amendment" is an application to change the text of Title 18 ACC. This type of application or initiation shall be processed as a legislative non-project decision, consistent with ACC 14.03.060. Public notice shall be provided consistent with Title 14 ACC.

Procedural Steps:

1. The proposed text amendment (zoning code update) has been discussed with the Planning Commission at a regular meeting on December 2, 2025.

2. Pursuant to Revised Code of Washington (RCW) 36.70A, the text amendment was transmitted to the Washington State Department of Commerce on September 3, 2025. The 60-day notice period ended on November 2, 2025. Staff received comments from the Dept. of Commerce on October 22, 2025.

3. ACC 18.68.030(B) outlines the Zoning Text Amendment requirements for this proposal.

    a. A "Zoning Text Amendment" is an application to change the text of ACC Title 18. This type of application or initiation shall be processed as a legislative nonproject decision, consistent with ACC 14.03.060. Public notice shall be provided consistent with ACC Title 14.
        i. Substantive Zoning Text Amendments. For the purposes of this chapter, substantive zoning text amendments shall be distinguished from procedural or administrative amendments in accordance with the following: "Substantive" matters relate to regulations that define or limit what can be done in terms of conduct, use or action (e.g., what land use may be made of property, what requirements apply to development, and what public infrastructure may be required of certain developments). "Procedural" or "administrative" matters are those that relate to the process of how an application to take such action must be pursued (e.g., time limits for decisions and appeals, what forms must be used, and where or how applications must be submitted. Essentially, "procedural" or "administrative" matters are the mechanical rules by which substantive issues may be pursued.) Substantive text amendments shall be reviewed by the planning commission and the planning commission shall conduct a public hearing and make a recommendation before being presented to the city council for consideration and action.
        ii. The text amendment proposed is a Substantive Zoning Text Amendment and requires a public hearing to be held by Planning Commission prior to City Council approval.

4. A Notice of Public Hearing (NOH) was issued on October 1, 2025, and re-issued on November 21, 2025. Pursuant to ACC 14.22.100, the following methods of noticing for the Planning Commission public hearing were conducted:
    a. The NOH was published in the Seattle Times on November 21, 2025.
    b. The NOH was posted in two general public locations (City Hall and City Annex).
    c. The NOH was posted on City's Public Land Use Notice webpage.

5. A public hearing will be conducted by the Planning Commission on December 2, 2025.

EXHIBITS:

1. PowerPoint Presentation
2. Co-Living Housing Text Amendment
3. Public Comments
4. Commerce Co-Living Guidance

Exhibit 1

PLANNING COMMISSION

CO-LIVING HOUSING TEXT AMENDMENT

PRESENTED BY
OWEN GOODE, PLANNER II
DECEMBER 2, 2025

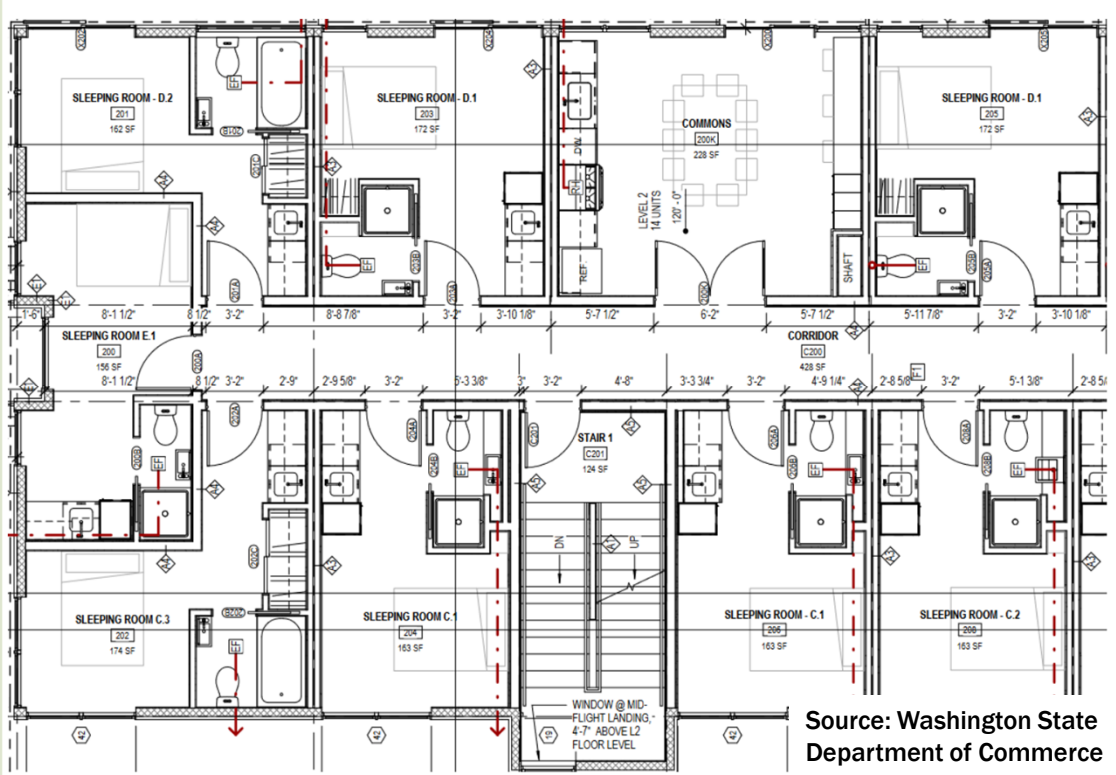
Department of Community Development
Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE
ENVIRONMENT
ECONOMY
CHARACTER
SUSTAINABILITY
WELLNESS
CELEBRATION

PURPOSE OF TEXT AMENDMENT

- **Must adopt code that allows for co-living housing**
- **Co-living housing is a denser housing typology**



Source: Washington State Department of Commerce

EFFECT OF TEXT AMENDMENT

- **Increase availability of affordable housing**



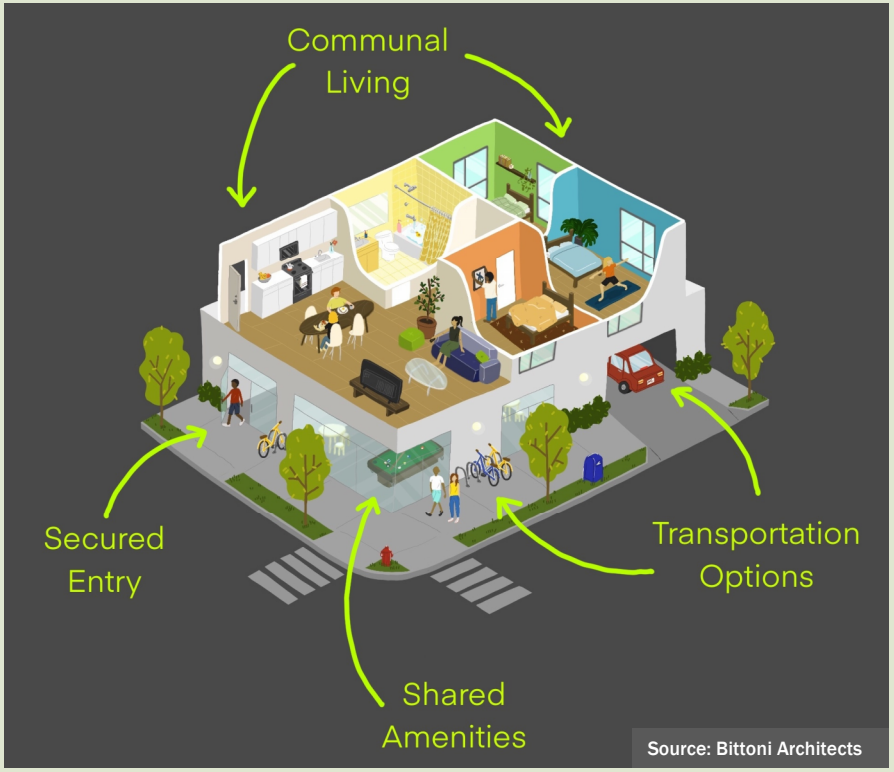




Source: Washington State Department of Commerce

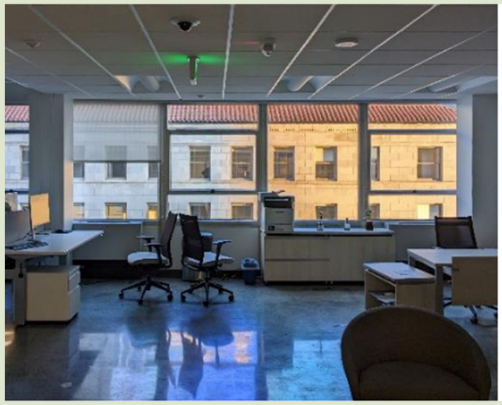
EFFECT OF TEXT AMENDMENT

- 0.25 Dwelling Unit
- 0.25 Parking Requirement
- No Short-Term Rental
- No bathroom AND kitchen



WHERE WILL CO-LIVING BE ALLOWED?

- All zones that allow for a <u>minimum</u> of 6 <u>multifamily</u> dwelling units
- Applies to the DUC, R-3, R-4, R-NM, C-2, C-AG, and M-1 zones







Source: Washington State Department of Commerce

REASON FOR TEXT AMENDMENT

- One of many tools to combat the current housing crisis
- Not a single solution to the housing crisis



Source: Opticos Design

RECOMMENDATION

Recommend approval of the draft text amendments to title 18 of the auburn city code which allows co-living housing as a permissible use within the Downtown Urban Center (DUC), R-3, R-4, R-NM, C-2, C-AG, and M-1 zones

QUESTIONS?

Department of Community Development

Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE

ENVIRONMENT

ECONOMY

CHARACTER

SUSTAINABILITY

WELLNESS

CELEBRATION

18.02.067 Units allowed per lot.

E. *Lot Area per Unit Above Base Allowance.* Additional units beyond what is allowed under ACC 18.25.040(A) are allowed based on lot area above the minimum lot size threshold. One additional unit is allowed above the base for each interval of the value shown in ACC 18.07.030(D)(3) up to the maximum number of units per lot (ACC 18.07.030(D)(4)), except for courtyard housing. For example: a lot with an area of 5,650 square feet in the R-2 zone may have one additional unit above the base of four because it is 1,250 square feet larger than the minimum lot size.

F. *Maximum Units per Lot.*

1. Except for courtyard housing, the total number of units shall not exceed the value listed in ACC 18.07.030(D)(3).

2. The maximum number of units for courtyard housing is two times the number of units listed in ACC 18.07.030(D)(4).

3. For the purpose of calculating density for co-living housing, one sleeping unit shall equate to 0.25 dwelling units. For example, a co-living housing development with 16 sleeping units would equate to 4 dwelling units.

Chapter 18.04
DEFINITIONS

Sections:

18.04.239 Co-living Housing

18.04.239 Co-living housing.

"Co-living housing" means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building.

18.04.340 Dwellings, types of.

"Types of dwellings" means:

A. *Dwelling, Single-Unit Detached.* "Single-unit detached" means a detached building, not connected to another building, designed exclusively for occupancy by one family or communal residence and containing one dwelling unit that is permanently attached to the ground. A manufactured home may be considered a single-unit detached dwelling if sited per ACC 18.31.050. This dwelling type was previously called "single family" and is synonymous with "single-unit detached housing."

B. *Dwelling, Middle Housing.* "Middle housing" dwellings include the following housing types:

1. "Townhouse" means a detached structure that contains three or more attached dwelling units that extend from foundation to roof and that have a yard or public way on not less than two sides, each with its own front and rear access to the outside.

2. "Duplex" means a detached structure consisting of two individual dwelling units that is in a horizontal or stacked layout, does not have interior openings between dwelling units, and which dwelling units share common walls.

3. “Triplex” means a detached structure consisting of three individual dwelling units that is in a horizontal or stacked layout, does not have interior openings between dwelling units, and which dwelling units share common walls.

4. “Fourplex” means a detached structure consisting of four individual dwelling units that is in a horizontal or stacked layout, does not have interior openings between dwelling units, and which dwelling units share common walls.

5. “Fiveplex” means a detached structure consisting of five individual dwelling units that is in a horizontal or stacked layout, does not have interior openings between dwelling units, and which dwelling units share common walls.

6. “Sixplex” means a detached structure consisting of six individual dwelling units that is in a horizontal or stacked layout, does not have interior openings between dwelling units, and which dwelling units share common walls.

7. “Stacked flat” means dwelling units in a residential building of no more than three stories on a lot in which each floor may be separately rented or owned. Duplexes and triplexes may be arranged as stacked flats.

8. “Cottage housing” means residential units on a lot with a common open space that either: (a) is owned in common; or (b) has units owned as condominium units with property owned in common and a minimum of 20 percent of the lot size as open space. Courtyard housing standards in ACC 18.25.050 apply to cottage housing. This definition of cottage housing does not apply to “guest cottages” of ACC 18.04.450.

9. “Courtyard apartments” means a residential structure consisting of multiple attached side-by-side and/or stacked dwelling units oriented around a yard or court on two or three sides.

C. *Dwelling, Apartment.* “Apartment” means a building designed for occupancy by seven or more families or communal residences living independently of each other and containing seven or more dwelling units. Apartment units may be located in a mixed-use development. This

dwelling type was previously called “multiple-family” dwellings. (Ord. 6959 § 1 (Exh. A), 2024; Ord. 6477 § 4, 2013; Ord. 6245 § 3, 2009; Ord. 6162 § 1, 2008; Ord. 4229 § 2, 1987.)

D. *Sleeping Unit*. Means a single unit that provides rooms or spaces for one or more people, includes permanent provisions for sleeping and can include provisions for living, eating and either sanitation or kitchen facilities but not both.

Chapter 18.07
RESIDENTIAL ZONES

Sections:

18.07.010 Intent.
18.07.020 Uses.
18.07.030 Development standards.

18.07.010 Intent.

A. *General.* This section describes the intent for each of the city's residential zones. These intent statements may be used to guide the interpretation of the regulations associated with each zone.

B. *RC Residential Conservancy Zone.*

1. RC residential conservancy zone is intended primarily to provide for low-intensity single-family residential uses with characteristics of an agricultural environment; provided, that the agricultural uses are secondary to the single-family uses. These areas allow for a lifestyle similar to that of rural areas that includes allowance of farm animals and streets without sidewalks. This zone is intended to protect areas with significant environmental constraints or values from impacts typically associated with urban levels of development while allowing low-intensity development designed to minimize impacts on the natural environmental features designated for conservation.

2. Public improvements required within the RC zone will be less than is normally required for the higher intensity residential zones within the city and are not subject to the city's complete streets policies.

3. This zone shall only be applied in areas designated as residential conservancy on the comprehensive plan.

C. *R-1 Residential Zone.*

1. The intent of the R-1 residential zone is to provide areas for estate-type residential development on large lots in areas that are intended to create an open space separation between existing urban areas that are unique from each other and where limited public utilities and transportation infrastructure are present.

Appropriate development standards required of other urban areas shall be required to serve this zone.

2. R-1 implements the Neighborhood Residential One comprehensive plan land use designation.

D. *R-2 Residential Low Zone.*

1. The R-2 residential low zone is intended for lower-intensity residential development consisting of single-unit detached houses, townhouse, duplex, triplex, fourplex, two-story stacked flats, courtyard apartments, cottage housing on lot sizes typical of suburban and urban development. This residential zone allows flexibility in the types and densities of housing permitted while at the same time maintaining a desirable family living environment by establishing minimum usable open spaces, maximum impervious coverage, and maximum units per lot area with the character and scale of traditional single-unit detached neighborhoods.

2. A related consideration of this zone is to provide a transition between low-intensity residential development areas and higher- and lower-intensity designations. Small-scale, community-based commercial development that provides services to the local neighborhood will be considered through the administrative use permit process.

3. R-2 implements the Neighborhood Residential Two comprehensive plan land use designation.

E. *R-3 Residential Moderate Zone.*

1. The intent of the R-3 residential moderate zone is to allow all residential and commercial types and uses provided in the R-2 residential zone, while allowing additional intensity through allowing stacked flats up to three stories, fiveplexes, ~~and~~ sixplexes, and co-living housing. Single-unit detached houses are not permitted in the R-3 zone. Apartment buildings and mixed-use development consisting of no more than 20 units and three stories per lot is permitted. Supportive housing and residential care developments

are permitted in this zone to provide additional needed housing options but must still adhere to the residential density and unit limitations established within this category. Small-scale commercial development providing services to the area is encouraged in this zone and implemented through the administrative use permit process.

2. R-3 implements the Neighborhood Residential Two comprehensive plan land use designation.

F. *R-4 Residential High Zone.*

1. The R-4 residential high zone is intended to maximize residential density opportunities and is further intended as a residential zone primarily of middle housing and multiple-story apartment and mixed-use development. This zone is characterized by a more active living environment near transit, urban services and commercial uses. The R-4 residential zone allows for all uses allowed in the R-3 zone, plus apartment and mixed-use development of more than 20 units and three stories per lot is permitted. Small-scale commercial development providing services to the area is encouraged in this zone and implemented through the administrative use permit process.

2. R-4 implements the Neighborhood Residential Three comprehensive plan land use designation.

G. *R-NM Residential Neighborhood Mixed-Use Zone.*

1. The intent of the R-NM residential neighborhood mixed-use zone is to provide a flexible approach that achieves a mix of dense residential development and light commercial uses in either a vertical or horizontal configuration. Within this zone there will be a mix of retail, office, middle housing, co-living housing, and multi-story residential uses, with attractive design and accessible spaces for people to live, work, and visit. This zoning designation is served primarily by a combination of transit, pedestrian, and/or bicycle facilities allowing people to access amenities without needing a personal vehicle. Uses and densities allowed within this zone will be consistent with the uses permitted in the C-1 light commercial and the densities of the R4 residential high zone. New development and redevelopment will incorporate a mix of residential and commercial uses. In addition, parks and open spaces are encouraged and may be permitted through the administrative use permit process.

2. Street-level development is encouraged to be retail or higher traffic local businesses or offices, and residential is encouraged on the upper levels of buildings. This zoning district should be walkable and bikeable to neighborhood commercial services and transit facilities and have a high level of street activation and amenities.

H. *R-F Residential Flex Zone.* The R-F residential-flex zone is intended primarily to accommodate small-scale business and professional offices, medical and dental clinics, salons and other personal services, eating and drinking establishments, and banks and similar financial institutions at locations where they are compatible with residential uses. Accessory retail may be permitted if supplemental to the other uses allowed in the zone. This zone is intended for those areas that are in transition from residential to commercial uses along corridors serving lower density residential land uses. Conversion of residential uses to commercial uses is geared towards encouraging adaptive reuse of existing single-unit structures that continue to appear in accord with the single-unit residential character. New development in the R-F residential-flex zone should not exceed two stories or footprint that is designed to maintain a character and a scale smaller than the R-NM residential neighborhood mixed-use residential zone. (Ord. 6959 § 1 (Exh. A), 2024; Ord. 6525 § 6, 2014; Ord. 6245 § 5, 2009.)

18.07.020 Uses.

Table 18.07.020. Permitted Use Table – Residential Zones

P = Permitted A = Administrative C = Conditional Use X = Not Permitted							
Land Uses	**Zoning Designations**						
	RC	**R-1**	**R-2**	**R-3**	**R-4**	**R-NM**	**R-F**
A. Residential Uses.							
Accessory dwelling units subject to the provisions contained in Chapter 18.32 ACC	P[1]	P[1]	P[1]	P[1]	P[1]	P[1]	P[1]
Accessory use, residential	P	P	P	P	P	P	P
Adult family home	P	P	P	P	P	P[1]	P

Apartments (7 units or more)	X	X	X	P[11]	P	P	X
Bed and breakfast or short-term rentals	P	P	P	P	P	X	P
Caretaker apartment	X	X	X	X	X	P	X
Co-living housing	X	X	X	P	P	P[13]	X
Communal residence	P	P	P	P	P	X	P
Foster care homes	P	P	P	P	P	X	P
Group residence facilities (7 or more residents)	X	X	X	P	P	P	P
Group residence facilities (6 or fewer residents)	P	P	P	P	P	P	P
Keeping of animals[4]	P[2]	P[2]	P[2]	P[2]	P[2]	P[2]	P[2]
Middle housing subject to the provisions in Chapter 18.25 ACC (2 to 6 units)	P	P	P	P	P	P	P
Neighborhood recreational buildings and facilities owned and managed by the neighborhood homeowners' association	A[6]	A[6]	A[6]	A[6]	A[6]	P	P
Use as dwelling units of (1) recreational vehicles that are not part of an approved recreational vehicle park, (2) boats, (3) automobiles, and (4) other vehicles	X	X	X	X	X	X	X
Renting of rooms, for lodging purposes only, to accommodate not more than two persons in addition to the family or owner occupied unit[8]	P	P	P	P	P	P	P
Residential care facilities including but not limited to assisted living facilities, convalescent homes, continuing care retirement facilities	P	P	P	P	P	P	P
Single-unit detached dwellings, new	P	P	P	X	X	X	P
Supportive housing (permanent), subject to the provisions of ACC 18.31.160	P	P	P	P	P	P	P
Swimming pools, tennis courts and similar outdoor recreation uses only accessory to	P	P	P	P	P	P	P

residential or park uses							
Townhouses (attached)	X	X	X	X	P	P	P
Transitional housing	P	P	P	P	P	P	P
B. Commercial Uses.							
Commercial horse riding and bridle trails	A	X	X	X	X	X	X
Commercial recreation facility, indoor	X	X	X	X	P	P	X
Commercial retail establishment	X	X	A	A	P	P	A
Convenience store	X	X	X	X	P	P	X
Daycare, limited to a mini daycare center. Daycare center, preschool or nursery school may also be permitted but must be located on an arterial	X	P	P	P	P	P	P
Grocery or specialty food store	X	X	X	A	P	P	A
Home-based (or family) daycare as regulated by RCW 35.63.185 and through receipt of approved city business license	P	P	P	P	P	P	P
Home occupations subject to compliance with Chapter 18.60 ACC	P	P	P	P	P	P	P
Marijuana cooperative	X	X	X	X	X	X	X
Marijuana processor	X	X	X	X	X	X	X
Marijuana producer	X	X	X	X	X	X	X
Marijuana-related business	X	X	X	X	X	X	X
Marijuana researcher	X	X	X	X	X	X	X
Marijuana retailer	X	X	X	X	X	X	X
Marijuana transporter business	X	X	X	X	X	X	X
Mixed-use development[310]	X	X	X	P	P	P	P

Personal service shop	X	X	A	P	P	P	P
Nursing homes	X	X	X	X	C	C	C
Privately owned and operated parks and playgrounds and not homeowners' association-owned recreational area	X	A	A	A	A	P	P
Professional offices	X	X	A	A	P[9]	P	P
Restaurant, café, or coffee shop	X	X	A	A	P	P	A
Neighborhood retail establishment	X	X	A	A	P	P	P
C. Resource Uses.							
Agricultural enterprise:[7]							
When 50 percent, or more, of the total site area is dedicated to active agricultural production during the growing season, and with 52 or less special events per calendar year	A[7]	X	X	X	X	X	X
When less than 50 percent of the total site area is dedicated to active agricultural production during the growing season, or with more than 52 special events per calendar year	C[7]	X	X	X	X	X	X
Agricultural type uses are permitted provided they are incidental and secondary to the single-family use:							
Agricultural crops and open field growing (commercial)	P	X	X	X	X	X	X
Barns, silos and related structures	P	X	X	X	X	X	X
Commercial greenhouses	P	X	X	X	X	X	X
Pasturing and grazing[4]	P	X	X	X	X	X	X
Public and private stables[4]	P	X	X	X	X	X	X
Roadside stands, for the sale of agricultural products raised on the premises. The stand cannot	P	X	X	X	X	X	X

exceed 300 square feet in area and must meet the applicable setback requirements.							
Fish hatcheries	C	X	X	X	X	X	X
D. Government, Institutional, and Utility Uses.							
Civic, social and fraternal clubs	X	X	X	X	A	A	A
Government facilities	A	A	A	A	A	A	A
Hospitals (except animal hospitals)	X	X	X	X	X	C	C
Municipal parks and playgrounds	A	P	P	P	P	P	P
Museums	X	X	X	X	A	A	A
Religious institutions, less than one acre lot size[12]	A	A	A	A	A	A	A
Religious institutions, one acre or larger lot size[12]	C	C	C	C	C	C	C
Transmitting towers	C	C	C	C	C	C	C
Type 1-D wireless communications facility (see ACC 18.04.912(W) and 18.31.100)	P	P	P	P	P	P	P
Eligible facilities request (EFR) (wireless communications facility – See ACC 18.04.912(H))	P	P	P	P	P	P	P
Utility facilities and substations	C[5]	C[5]	C[5]	C[5]	C[5]	C[5]	C[5]
Small wireless facilities (ACC 18.04.912(Q))	P	P	P	P	P	P	P

1 An accessory dwelling unit may be permitted with an existing single-unit residence pursuant to Chapter 18.32 ACC.

2 Please see the supplemental development standards for animals in ACC 18.31.220.

3 Individual uses that make up a mixed-use development must be permitted within the zone. If a use making up part of a mixed-use development requires an administrative or conditional use permit, the individual use must apply for and receive the administrative or conditional use approval, as applicable.

4 Proximity of pasture or livestock roaming area to wells, surface waters, and aquifer recharge zones is regulated by the King or Pierce County board of health, and property owners shall comply with the provisions of the board of health code.

5 Excludes all public and private utility facilities addressed under ACC 18.02.040(E).

6 Administrative use permit not required when approved as part of a subdivision or binding site plan.

7 Agricultural enterprise uses are subject to supplemental development standards under ACC 18.31.210, Agricultural enterprises development standards.

8 An owner occupant that rents to more than two persons but no more than four persons is required to obtain a city of Auburn rental housing business license and shall meet the standards of the International Property Maintenance Code.

9 As component of mixed-use developments and/or office ground floor uses permitted up to 5,000 square feet.

10 Commercial uses permitted outright, or allowed administratively or conditionally in this table may be allowed as part of mixed-use development.

11 Apartment buildings and mixed-use development consisting of no more than 20 units and three stories per lot is permitted.

12 Reference ACC 18.31.165 for standards related to homeless encampments hosted by a religious organization.

13 When provided in the R-NM Zone, a mixed-use component shall not be required as part of the project approval.

(Ord. 6977 § 1 (Exh. A), 2025; Ord. 6959 § 1 (Exh. A), 2024; Ord. 6799 § 5 (Exh. E), 2020; Ord. 6642 § 4, 2017; Ord. 6600 § 9, 2016; Ord. 6565 § 2, 2015; Ord. 6560 § 9, 2015; Ord. 6477 § 8, 2013; Ord. 6369 § 2, 2011; Ord. 6363 § 3, 2011; Ord. 6269 § 3, 2009; Ord. 6245 § 5, 2009.)

18.23.030 Uses.

A. *General Permit Requirements.* Table 18.23.030 identifies the uses of land allowed in each commercial and industrial zone and the land use approval process required to establish each use.

B. *Requirements for Certain Specific Land Uses.* Where the last column (Standards for Specific Land Uses) in Table 18.23.030 includes a reference to a code section number, the referenced section determines other requirements and standards applicable to the use regardless of whether it is permitted outright or requires an administrative or conditional use permit.

C. *Uses Affected by the Airport Overlay.* Refer to Chapter 18.38 ACC to determine whether uses are separately prohibited by that chapter or will be required to comply with additional regulations that are associated with the airport overlay.

Table 18.23.030. Permitted, Administrative, Conditional and Prohibited Uses by Zone, Commercial and Industrial Zones

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						**P – Permitted** **C – Conditional** **A – Administrative** **X – Prohibited**
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
INDUSTRIAL, MANUFACTURING AND PROCESSING, WHOLESALING						
Building contractor, light	X	P	X	P	P	
Building contractor, heavy	X	X	X	A	P	
Manufacturing, assembling and packaging – Light intensity	X	P	X	P	P	ACC 18.31.180

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Manufacturing, assembling and packaging – Medium intensity	X	A	X	P	P	ACC 18.31.180
Manufacturing, assembling and packaging – Heavy intensity	X	X	X	X	A	ACC 18.31.180
Marijuana processor	X	X	X	C	C	Chapter 18.59 ACC
Marijuana producer	X	X	X	C	C	Chapter 18.59 ACC
Marijuana researcher	X	X	X	C	C	Chapter 18.59 ACC
Marijuana retailer	X	C	X	C	C	Chapter 18.59 ACC
Marijuana transporter business	X	X	X	C	C	Chapter 18.59 ACC
Outdoor storage, incidental to principal permitted use on property	X	P	X	P	P	ACC 18.57.020(A)
Storage – Personal household storage facility (mini-storage)	P	P	X	P	P	ACC 18.57.020(B)
Warehousing and distribution	X	X	X	P	C	ACC 18.57.020(C)
Warehousing and distribution, bonded and located within a designated foreign trade zone	X	P	X	P	P	

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Wholesaling with on-site retail as an incidental use (e.g., coffee, bakery)	X	P	X	P	P	
RECREATION, EDUCATION AND PUBLIC ASSEMBLY USES						
Commercial recreation facility, indoor	P	P	P	P	A	
Commercial recreation facility, outdoor	X	A	A	P	A	ACC 18.57.025(A)
Conference/convention facility	X	A	X	A	X	
Library, museum	A	A	X	A	X	
Meeting facility, public or private	P	P	X	A	A	
Movie theater, except drive-in	P	P	P	X	X	
Private school – Specialized education/training (for profit)	A	P	P	P	P	
Religious institutions, lot size less than one acre	P	P	A	A	A	ACC 18.31.165
Religious institutions, lot size more than one acre	P	P	A	A	A	ACC 18.31.165
Sexually oriented businesses	X	P	X	P	P	Chapter 18.74 ACC

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Sports and entertainment assembly facility	X	A	X	A	A	
Studio – Art, dance, martial arts, music, etc.	P	P	P	P	A	
RESIDENTIAL						
Apartment units, as part of a mixed-use development [2]	X	P	P	P	X	ACC 18.57.030
Apartments, standalone	X	X	X	X	X	
Caretaker apartment	P	P	X	P	P	
Co-living housing [4]	X	P	P	P	X	
Indoor emergency housing or shelter	P	P	P	A	A	ACC 18.31.160
Live/work unit, as part of a mixed-use development [2]	X	P	P	P	X	
Live/work unit, standalone [3]	X	X	X	X	X	
Work/live unit, as part of a mixed-use development [2]	X	P	P	P	X	
Work/live unit, standalone [3]	X	X	X	X	X	

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Marijuana cooperative	X	X	X	X	X	
Nursing home, assisted living facility	P	P	C	X	X	
Senior housing[2]	X	A	X	X	X	
Supportive housing (permanent)	P	P	P	A	A	ACC 18.31.160
Transitional housing	P	P	P	A	A	ACC 18.31.160
RETAIL						
Building and landscape materials sales	X	P	X	P	P	ACC 18.57.035(A)
Community retail establishment	P	P	P	P	P	
Construction and heavy equipment sales and rental	X	X	X	A	P	
Convenience store	A	P	X	P	P	
Drive-through espresso stands	A	P	A	P	A	
Drive-through facility, including banks and restaurants	A	P	P	P	P	ACC 18.52.040
Entertainment, commercial	A	P	X	A	A	

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Groceries, specialty food stores	P	P	P	P	X	
Neighborhood retail establishment	P	P	P	P	P	
Nursery	X	P	A	P	P	ACC 18.57.035(C)
Outdoor displays and sales associated with a permitted use (auto/vehicle sales not included in this category)	P	P	P	P	P	ACC 18.57.035(D)
Regional retail establishment	X	P	P	P	A	
Restaurant, cafe, coffee shop	P	P	P	P	P	
Tasting room	P	P	P	P	P	
Tavern	P	P	P	P	A	
Wine production facility, small craft distillery, small craft brewery	P	P	P	P	P	
SERVICES						
Animal daycare (excluding kennels and animal boarding)	A	P	A	P	P	ACC 18.57.040(A)
Animal sales and services (excluding kennels	P	P	P	P	P	ACC 18.57.040(B)

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
and veterinary clinics)						
Banking and related financial institutions, excluding drive-through facilities	P	P	P	P	P	
Catering service	P	P	A	P	P	
Daycare, including mini daycare, daycare center, preschools or nursery schools	P	P	P	P	X	
Dry cleaning and laundry service (personal)	P	P	P	P	P	
Equipment rental and leasing	X	P	X	P	P	
Kennel, animal boarding	X	A	X	A	A	ACC 18.57.040(C)
Government facilities; this excludes offices and related uses that are permitted outright	A	A	A	A	A	
Hospital	P	P	X	P	P	
Lodging – Hotel or motel	P	P	P	A	A	
Medical – Dental clinic	P	P	P	P	X	
Mortuary, funeral home, crematorium	P	P	X	P	X	

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Personal service shops	P	P	P	P	X	
Pharmacies	P	P	P	X	X	
Print and copy shop	P	P	P	P	X	
Printing and publishing (of books, newspaper and other printed matter)	A	P	P	P	P	
Professional offices	P	P	P	P	P	
Repair service – Equipment, appliances	A	P	P	P	P	ACC 18.57.040(D)
Veterinary clinic, animal hospital	P	P	P	P	X	
Youth community support facility	P	X	X	X	X	ACC 18.57.040(E)
TRANSPORTATION, COMMUNICATIONS AND INFRASTRUCTURE						
Ambulance, taxi, and specialized transportation facility	X	A	X	P	P	
Broadcasting studio	P	P	X	P	P	
Heliport	X	C	X	C	C	
Motor freight terminal[1]	X	X	X	X	X	See Footnote No. 1

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						P – Permitted C – Conditional A – Administrative X – Prohibited
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Parking facility, public or commercial, surface	P	P	P	P	X	
Parking facility, public or commercial, structured	P	P	P	P	X	
Towing storage yard	X	X	X	A	P	ACC 18.57.045(A)
Utility transmission or distribution line or substation	A	A	A	A	A	
Wireless communications facility (WCF) (See ACC 18.04.912(W))	*	*	*	*	*	*See ACC 18.31.100 for use regulations and zoning development standards.
Eligible facilities request (EFR) (wireless communications facility) (See ACC 18.04.912(H))	P	P	P	P	P	
Small wireless facilities (ACC 18.04.912(Q))	P	P	P	P	P	
VEHICLE SALES AND SERVICES						
Automobile washes (automatic, full or self-service)	A	P	P	P	P	ACC 18.57.050(A)
Auto parts sales with installation services	A	P	P	P	P	

PERMITTED, ADMINISTRATIVE, CONDITIONAL AND PROHIBITED USES BY ZONE						**P – Permitted** **C – Conditional** **A – Administrative** **X – Prohibited**
LAND USE	**Zoning Designation**					**Standards for Specific Land Uses**
	C-1	**C-2**	**C-AG**	**M-1**	**M-2**	
Auto/vehicle sales and rental	A	P	X	P	P	ACC 18.57.050(B)
Fueling station	A	P	P	P	P	ACC 18.57.050(C)
Mobile home, boat, or RV sales	X	P	X	P	P	
Vehicle services – Repair/body work	X	P	X	P	P	ACC 18.57.050(D)
OTHER						
Any commercial use abutting a residential zone which has hours of operation outside of the following: Sunday: 9:00 a.m. to 10:00 p.m. or Monday – Saturday: 7:00 a.m. to 10:00 p.m.	A	A	A	A	A	
Other uses may be permitted by the planning director or designee if the use is determined to be consistent with the intent of the zone and is of the same general character of the uses permitted. See ACC 18.02.120(C)(6), Unclassified Uses.	P	P	P	P	P	

1 Any motor freight terminal, as defined by ACC 18.04.635, in existence as of the effective date of the ordinance codified in this section, is an outright permitted use in the M-1 and M-2 zones. Any maintenance, alterations and additions to an existing motor freight terminal which are consistent with ACC 18.23.040, Development standards, are allowed.

2 Any mixed-use development or senior housing project vested prior to Resolution No. 5187 (December 7, 2015) is an outright permitted use in the C-1 zone. Subsequently, if a nonresidential use within a vested

mixed-use development changes, then the nonresidential use shall maintain a minimum of 10 percent of the cumulative building ground floor square footage consisting of the uses permitted outright, administratively, or conditionally, listed under “Recreation, Education, and Public Assembly,” “Retail,” or “Services” of the C-1 zone.

3 Any standalone live/work units or standalone work/live units vested prior to the effective date of the ordinance codified in this chapter are outright permitted uses.

4 Co-living housing provided in this zone shall not be required to provide a mixed-use component.

(Ord. 6977 § 1 (Exh. A), 2025; Ord. 6959 § 1 (Exh. A), 2024; Ord. 6885 § 1 (Exh. A), 2022; Ord. 6838 § 1 (Exh. A), 2021; Ord. 6799 § 6 (Exh. F), 2020; Ord. 6728 § 3 (Exh. C), 2019; Ord. 6688 § 1 (Exh. 1), 2018; Ord. 6644 § 2, 2017; Ord. 6642 § 9, 2017; Ord. 6508 § 1, 2014; Ord. 6433 § 26, 2012.)

Chapter 18.31
SUPPLEMENTAL DEVELOPMENT STANDARDS

Sections:

18.31.010 **Daycare standards.**
18.31.020 **Fences.**
18.31.025 **Retaining walls.**
18.31.030 **Height limitations – Exceptions.**
18.31.040 **Lots.**
18.31.050 **Single-unit detached siting and design standards.**
18.31.060 **Recreational vehicle parks.**
18.31.070 **Setbacks.**
18.31.080 **Heliports.**
18.31.090 **Work release, prerelease and similar facilities.**
18.31.100 **Wireless communications facilities siting standards.**
18.31.110 **Siting of small wireless facilities.**
18.31.115 **Wetland mitigation.**
18.31.120 ***Repealed.***
18.31.130 **Communal residence standards.**
18.31.140 **Gated residential subdivisions.**
18.31.150 **Secure community transition facilities.**
18.31.160 **Supplemental standards for transitional housing, permanent supportive housing, indoor emergency shelters, and indoor emergency housing.**
18.31.161 **Supplemental standards for co-living housing.**
18.31.165 **Homeless encampment hosted by a religious organization.**
18.31.170 ***Reserved.***
18.31.180 **Performance standards.**
18.31.190 **Supplemental standards for residential mobile home communities.**
18.31.200 **Architectural and site design review standards and regulations.**
18.31.210 **Agricultural enterprises development standards.**
18.31.220 **Permitted animals.**
18.31.230 ***Repealed.***

18.31.161 Supplemental standards for co-living housing.

A. General Standards. Co-living housing allowed pursuant to ACC 18.07.020 and 18.23.030 shall comply with the development standards of the underlying zone.

B. Co-living housing is exempt from the following:

1. Containing room dimensional standards larger than that required by the state and/or international building code, including dwelling unit size, sleeping unit size, room area, and habitable space;

2. Providing a mix of unit sizes or number of bedrooms;

3. Including other uses or containing a mixed-use component;

4. Providing off-street parking within one-half mile walking distance of a major transit stop;

5. Providing more than 0.25 off-street parking spaces per sleeping unit;

6. Containing standards for that are more restrictive than those that are required for other types of multifamily residential uses in the same zone; and

7. Receiving a density calculation that exceeds one-quarter or 0.25 of a dwelling unit per sleeping unit.

C. Nothing in this section shall be construed to preclude co-living housing developments from participating in affordable housing incentive programs under RCW 36.70A.540.

D. Co-living housing shall only require a review, notice, or public meeting for co-living housing that is required for other types of residential uses in the same location, unless otherwise required by state law including, but not limited to, shoreline regulations.

E. Co-living housing shall not be used as short-term rental units, rented for a period of less than 30 days.

18.52.020 Number of off-street parking spaces required.

Each principal use of the land, building, or structure shall provide the number of off-street parking spaces required by this section. The following standards are not applicable in the DUC, downtown urban center zone; refer to Chapter 18.29 ACC for specific requirements for that zone.

A. Parking Requirements by Land Use.

1. *Minimum Number of Parking Spaces.* Each land use shall provide the minimum number of off-street parking spaces required by Table 18.52.020, except where a greater number of spaces are required through a more specific approval process such as an administrative use permit or conditional use permit approval.

2. *Uses Not Listed.* Where a use is not listed in Table 18.52.020, the planning director shall determine the number of required parking and/or loading spaces. The planning director shall use the requirements in Table 18.52.020 as a guide in determining the number of off-street parking spaces required based on the similarity of uses or may consider a parking generation study.

B. *Maximum Number of Parking Spaces.* Except for required parking spaces for persons with disabilities, spaces provided in park and ride lots operated by a public transit agency, spaces for carpools, spaces for electric vehicle charging and spaces within structured parking with two or more levels, the maximum number of parking spaces for nonresidential uses shall not exceed 125 percent of the minimum spaces required by Table 18.52.020.

C. *Measurement of Floor Area.* In any case where Table 18.52.020 establishes a parking requirement based on floor area in square feet (for example: two spaces per 1,000 square feet (sf) of floor area), the floor area shall be construed to mean gross floor area (defined in ACC 18.04.430).

D. *Use With Accessory Components.* A single use with accessory components shall provide parking for the primary use, and each component. For example, a hotel with a meeting room may be required to provide the parking spaces required by Table 18.52.020 for a hotel (i.e., the guest rooms), and for a meeting room.

E. *Obstruction.* Removal of required parking or loading spaces from practical use by obstruction, erection of buildings, or other actions as to reduce the parking or loading capacity or usefulness thereof below the minimum requirements established in this chapter is prohibited.

F. *Existing Legally Nonconforming Gravel Spaces.* Up to six legally nonconforming gravel parking spaces may be used to meet off-street parking requirement for residential development.

Table 18.52.020. Off-Street Parking Requirements by Land Use

Land Use Type:	Unit of Measure:	Required Parking Rate (spaces per unit of measure):[6]
Residential Categories		
Single-unit detached dwelling, adult family home, home-based daycares	Dwelling unit	2.00
Middle housing (2 to 6 units)	See Chapter 18.25 ACC for middle housing parking requirements.	
Apartments (7 or more units)	Dwelling unit	0.50
Mobile home dwellings[1]	Dwelling unit	2.00
Assisted living facilities and senior housing	Per unit	0.00
Permanent supportive housing, transitional housing, emergency housing, and emergency shelters	Per unit	0.00
Group living (includes boardinghouse)	4 bedrooms	1.00
Co-living housing[7]	1 Sleeping Unit	0.25
Commercial Categories		

Land Use Type:	Unit of Measure:	Required Parking Rate (spaces per unit of measure):[6]
Auto sales and motorcycle, new	1,000 sf of floor area	2.29
Auto sales and motorcycle, used	1,000 sf of floor area	3.08
Daycare centers	Each 10 children in care	2.00
Eating and drinking establishments	1,000 square feet of floor area	8.00
Food retail stores and markets	1,000 square feet of floor area	5.00
Health and fitness clubs	1,000 square feet of floor area	5.00
Hotel or motel	Guest room or rental unit	1.00
Mini-marts and gas stations	1,000 square feet of floor area	5.00
Mortuaries or funeral homes	25 square feet of floor space	0.25
Motor vehicle repair and services	1,000 square feet of floor area	2.50
Personal service shops	1,000 square feet of floor area	2.50
Retail commercial establishments, less than 15,000 square feet of floor area	1,000 square feet of floor area	2.50
Retail commercial establishments, greater than 15,000 square feet of floor area	1,000 square feet of floor area	4.00
Shopping centers	1,000 square feet of floor area	4.00 [4]
Office Categories		
Business and professional offices	1,000 square feet of floor area	2.00

Land Use Type:	Unit of Measure:	Required Parking Rate (spaces per unit of measure):[6]
Medical-dental clinic; urgent care	1,000 square feet of floor area	3.00
Manufacturing Processing and Warehousing Categories ***(See also ACC 18.52.020(D))***		
All manufacturing, industrial, and processing uses, except the following:	1,000 square feet of floor area	1.00
Warehousing	2,000 square feet of floor area	1.00
Storage – Personal storage/mini-storage facilities	1,000 square feet of floor area[2]	0.10
Recreation, Education, Public Assembly Categories		
Auditoriums, stadiums, and theaters	25 square feet of floor space	0.25
Commercial recreation facilities – Indoor, except for the following:	1,000 square feet of floor area	5.00
Bowling alleys	Lanes	5.00
Pool and billiard rooms	Table	2.00
Skating rinks	1,000 square feet of floor area	5.00
Commercial recreation facilities – Outdoor	1,000 square feet of usable recreational area	3.00
Hospitals	Bed	1.75
Library, museum	1,000 square feet of floor area	2.50

Land Use Type:	Unit of Measure:	Required Parking Rate (spaces per unit of measure):[6]
Meeting facility, public or private	25 square feet of floor space	0.25
Religious assembly	25 square feet of floor space	0.20
Schools (public and private)		
Preschool schools	Employee[3]	1.00
Elementary/middle schools	Teaching station	1.20
Secondary (high) schools	Student	0.40
College or university (including trade and business schools)	Student	0.75
Studios (dance, martial arts, etc.)	1,000 square feet of floor area	5.00
Tennis/racquetball/handball or other sport courts	Court	2.00
	Each 300 sf of floor area for accessory uses	1.00
Recreational uses not listed elsewhere	Same as retail, based on size	

Notes:

1 Within mobile home parks, parking space shall not be allowed within the required setbacks. Guest parking shall be provided within the development: five percent of total requirement.

2 Includes total on-site building square feet.

3 There shall be two visitor-parking stalls provided for each 10 required employee stalls.

4 Compliance with these standards is not required for a change of use within an existing building.

5 Employee and customer parking only.

6 If the rate ends in .5 and above the number of parking spaces is rounded up to the next full number to provide the total number of parking spaces required.

7 Off-street parking shall not be required within one-half mile walking distance of a major transit stop as defined by RCW 36.70A.535(11)(b)

(Ord. 6977 § 1, 2025; Ord. 6959 § 1 (Exh. A), 2024; Ord. 6419 § 5, 2012; Ord. 6388 § 1, 2011; Ord. 6167 § 4, 2008; Ord. 6140 § 2, 2007; Ord. 6071 § 3, 2007; Ord. 5777 § 1, 2003; Ord. 5556 § 1, 2001; Ord. 5170 § 1, 1998; Ord. 4949 § 1, 1997; Ord. 4304 § 1(40), (41), 1988; Ord. 4229 § 2, 1987.)

Exhibit 3

Owen Goode

From: Guida, Eric (COM) <eric.guida@commerce.wa.gov>
Sent: Wednesday, October 22, 2025 9:38 AM
To: Planning; Gabriel Clark
Cc: Alexandria Teague; Vespier, Lilith (COM)
Subject: Planview Submittal #2025-S-9818, Auburn's draft co-living housing amendment

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

Good morning, Owen and Gabriel,

Thank you for uploading submittal #2025-S-9818, Auburn's draft co-living housing amendment, to Planview for agency review.

We have reviewed the submittal against our Co-Living Housing Checklist, and find that it is consistent with the requirements of the checklist – well done.

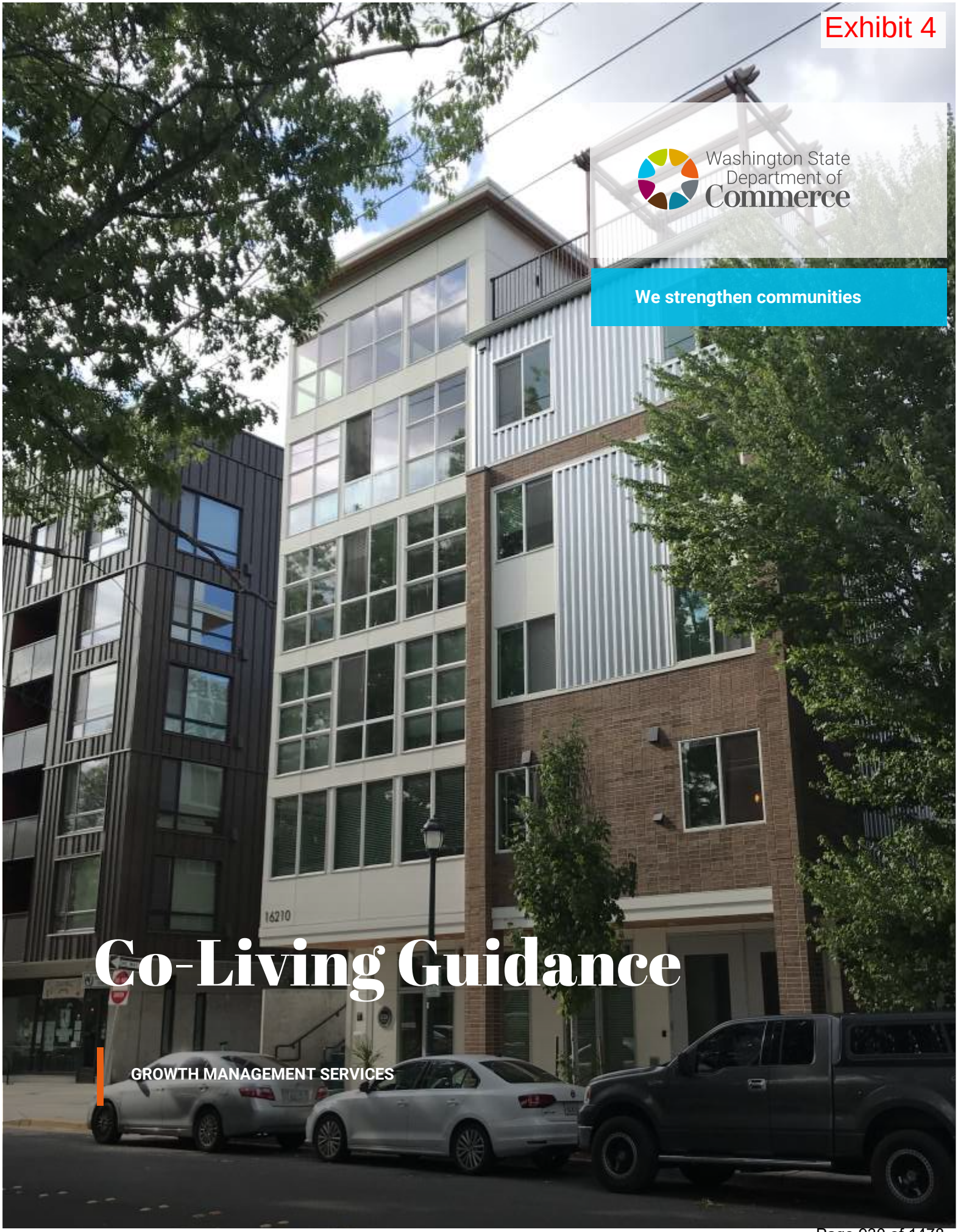
We don't see that the amendment addresses one provision, however: to treat a sleeping unit in co-living housing as no more than one-half of a dwelling unit for purposes of calculating fees for sewer connections. It's possible that this is addressed elsewhere in your code, and it's also possible that the City does not provide sewer services, in which case the provision doesn't apply. This is not a major concern, but we do want to point it out.

Regards,

Eric Guida | Senior Planner
Direct: 360.725.3044
Email: eric.guida@commerce.wa.gov

https://www.commerce.wa.gov/serving-communities/growth-management/

Exhibit 4



Washington State Department of Commerce

We strengthen communities

Co-Living Guidance

GROWTH MANAGEMENT SERVICES

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For people with disabilities, this report is available on request in other formats. To submit a request, please call 360-725-4000 (TTY 360-586-0772). Published January 2025.

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1.0 Introduction

1.1 Purpose and Legal Background

Guidance Purpose

This guidance is intended to support planners, advisory bodies, elected officials and interested parties in implementing code amendments related to RCW 36.70A.535, and to help readers understand best zoning practices for co-living housing. This guidance uses diagrams, references to public informational documents, and real-world examples to offer recommendations and best practices for the development of co-living housing.

State Law

The Washington Legislature passed Engrossed 2nd Substitute House Bill 1998 ("E2SHB 1998", commonly referred to as "HB 1998") in 2024. The provisions of HB 1998 are codified in RCW 36.70A.535. HB 1998 requires cities and counties planning under the Growth Management Act to adopt development regulations allowing co-living as a permitted use on any lot located within an urban growth area that allows at least six multifamily residential units, including on a lot zoned for mixed-use development. The bill provides standards for unit size, parking, density, fees, and other development regulations.

1.2 Applicability to Jurisdictions

The requirements of co-living are applicable to all "fully planning" counties and the cities and towns within those counties. To know if your community is in a fully planning county, visit the Commerce interactive map. [1]

Statutory Deadlines

Requirements for co-living take effect December 31, 2025.[2] By this date, subject cities and counties must adopt or amend co-living housing standards, consistent with RCW 36.70A.535, by ordinance and incorporate co-living housing into their development regulations, zoning regulations, and other official controls. If updates to bring co-living standards into alignment with statutory requirements are not completed by this date, the requirements of RCW 36.70A.535 will "supersede, preempt, and invalidate any conflicting local development regulations."

Under this statute, any action taken by a city or county to comply with the requirements of the co-living housing law is not subject to legal challenge under the Growth Management Act or the State Environmental Policy Act.[3]

---

[1] Department of Commerce. "The Growth Management Act status of Washington counties and cities." April 2017. https://deptofcommerce.app.box.com/s/z8ygn0ifeimybnlh4j6v8cl1wxkp1jfa
[2] RCW 36.70A.535(9)(a)
[3] RCW 36.70A.535(10)

1.3 Co-Living Background

What is Co-Living?

State law provides a definition of co-living housing:

> *"Co-living housing" means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building. Local governments may use other names to refer to co-living housing including, but not limited to, congregate living facilities, single room occupancy, rooming house, boarding house, lodging house, and residential suites.*[4]

Many terms are used to refer to co-living housing. In addition to those noted in the statute, co-living housing may be referred to as micro-units, dormitories, or another term. More information on the different types of co-living housing is included in "Overlapping Names and Use Types" on page 7.

Benefits

Co-living housing has many benefits, including:

- Providing market-rate, non-subsidized rental homes affordable to people in the workforce earning as low as 50% of area median income (older co-living units in Spokane area cost $350 per month, and in the Puget Sound suburbs some new co-living units are renting for $1,000 per month)
- Offering housing options for people who want a low-cost, private alternative to living with roommates
- Creating a living arrangement with shared community spaces that facilitate social connections
- Increasing affordable housing options in high opportunity neighborhoods with transportation access
- Reducing sprawl and vehicle miles traveled through infill development. This may in turn reduce auto emissions, energy use, and pollution

Stakeholders note that co-living is a great option for seniors looking to downsize their living arrangements and that co-living helps build communities and reduce loneliness for people of all ages. Co-living may be an attractive housing option for many community members and is an effective way to help accommodate housing needs for the state's growing population. More information on benefits of co-living is included in the Legislature's findings in the notes section of RCW 36.70A.535 under "Intent—Findings—2024 c 180."

History

Co-living housing types have a long history in America. Co-living housing was common in the pre-Revolutionary era and represented a larger share of urban housing stock by the turn of the 20th century. As norms and cultural values shifted in the post-WWII period, co-living buildings became stigmatized and new co-living developments were prohibited in many cities.

In Washington, co-living development had a resurgence in the Puget Sound region beginning in the 2000's, as the need for new low-cost apartments in desirable neighborhoods sparked interest in co-living housing among

[4] RCW 36.70A.535(11)(a)

local developers. These modern co-living buildings improved on the design quality and amenities of twentieth century models. For examples and more history on co-living housing, see Appendix A.

2.0 Development Regulations

This section provides recommendations and considerations for meeting the co-living development regulation requirements of RCW 36.70A.535.

Implementing regulations should respond to each jurisdictions' code framework. In addition to zoning code, cities and counties should review potential barriers in other regulatory areas which may result in conflicts that prohibit co-living housing development and may be preempted by state law. This may include Public Works standards, design standards, fire and tree code, and more.



Zoning is just the tip of the regulatory iceberg. Source: MAKERS

2.1 Applicability and Permitting

Applicability to Lots and Zones

Per RCW 36.70A.535(1), "Cities and counties planning under this chapter must allow co-living housing as a permitted use on **any lot located within an urban growth area that allows at least six multifamily residential units,** including on a lot zoned for mixed-use development."

The term "multifamily" is not defined by the Growth Management Act. For the purposes of co-living, Commerce interprets "multifamily residential units" to mean any type of housing which allows at least six units on a lot, excluding manufactured home parks, group homes (such as assisted living for seniors or people with disabilities), emergency housing, or emergency shelters.

Co-living housing must be a permitted use on any lot if:

- Six or more multifamily residential units are permitted under both the land use permissions and density or lot size standards. This includes lots where multifamily use is permitted to be mixed with non-residential uses (i.e. mixed-use development).
- A lot is subject to the minimum residential density and transit proximity requirements of RCW 36.70A.635(1)(b)(ii).

Cities are not required to allow co-living housing on lots where six units are permitted only through an affordable housing density bonus, such as under RCW 36.70A.635(1)(b)(iii).

Permit Type and Public Notice

Standards for permitting co-living housing must be no more restrictive than permitting standards for other types of multifamily housing in the same zone, per RCW 36.70A.535(4). For example, if multifamily housing is permitted outright, co-living housing must be permitted outright. Commerce recommends local governments consider updating land use matrices and allowable use tables to eliminate conditional use permits and administrative conditional use permits for all housing types— including multifamily housing, low-income

housing, and senior housing— to reduce barriers to housing that has traditionally been more difficult to permit.

Per RCW 36.70A.535(5), co-living housing may only be subject to the review, notice, and public meeting requirements that are applied to other types of residential uses in the same location, unless otherwise required by state law, such as shoreline permit regulations under Chapter 90.58 RCW.

Overlapping Names and Use Types

Some jurisdictions already define and regulate co-living uses by different names. Jurisdictions should review their codes for terms identified in RCW 36.70A.535— *congregate living facilities, single room occupancy, rooming house, boarding house, lodging house, and residential suites— as* well as micro-units and dormitories. Regardless of the name, uses meeting the statutory definition of co-living housing are subject to the requirements of RCW 36.70A.535. Where appropriate, consolidating related co-living uses in zones where they must be allowed under RCW 36.70A.535, may provide clarity of land uses, ease of administration, and demonstrating consistency with the law.

Uses that should not be regulated as co-living housing include group living uses that fall under another state law framework with regard to licensing, occupancy and/or zoning standards, such as assisted living facilities (Chapter 18.20 RCW), adult family homes (Chapter 70.128 RCW), or group homes (which are overseen by the Department of Social and Health Services (DSHS)). Emergency shelters, transitional housing, emergency housing, and permanent supportive housing (STEP) should not be combined with co-living or similar housing types (RCW 35.21.683 and RCW 36A.21.430). As a residential use, co-living differs from short-term rentals and should not be grouped with these uses.

Co-living is also different than co-housing, which is a type of ownership model that features fully equipped dwelling units that share common spaces. Co-housing is a community where people live in their own homes while sharing some facilities and spaces.

For more on non-overlapping housing types, see Commerce's "STEP and Other Housing Definition Fact Sheet."

Where Co-Living Allowance is Not Required

In some cases, jurisdictions may define uses which fall under the broader co-living definition, and which are allowed in areas where consistency with RCW 36.70A.535 is not required (i.e. zones where less than six multifamily residential units are allowed per lot). In these cases, retaining the more specific definitions is recommended when they provide a different type of housing option, provide for few sleeping units, or housing in other zoning districts. A common example may be boarding house.

2.2 Mix of Uses

RCW 36.70A.535(2)(c) prohibits jurisdictions from requiring co-living housing to "include other uses."

This means that the co-living use cannot be singled out in a general zone-wide or citywide requirement to contain other uses, such as ground-floor commercial uses. However, under RCW 36.70A.535(4), location-specific requirements for ground-floor non-residential uses that apply to multifamily housing can apply to co-living housing. Many larger co-living buildings have historically included a mix of retail and service uses to serve the upstairs residents and surrounding neighborhood.

2.3 Definitions, density and room dimensions

Co-Living Definition

The co-living definition in RCW 36.70.535(11)(a) states: *"Co-living housing" means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building."*

Because dwelling units can also be *"independently rented and lockable and provide living and sleeping space,"* jurisdictions should adopt clear standards to distinguish co-living sleeping units from dwelling units. Guidance is provided in the following sections.

Co-Living Density

RCW 36.70A.535(7) states: *"A city or county may not treat a sleeping unit in co-living housing as more than one-quarter of a dwelling unit for purposes of calculating dwelling unit density."*

This means that in a zone with a maximum density of 30 dwelling units per acre, a co-living housing development on a one-acre site must be permitted to build co-living housing with up to 120 sleeping units, as long as all other development regulations are met. In zones where there is no density limit for multifamily housing, there should also be no density limit for co-living housing.

Limits On Number of Units

A cap on the number of co-living sleeping units allowed per building is invalid when there are no equivalent limits on the number of units permitted in a multifamily building in the same zone, per RCW 36.70A.535(5). This requirement does not apply to zones where co-living is permitted beyond the locational requirements of RCW 36.70S.535(1). In those areas, the number of sleeping units per co-living building may be limited to less than the maximum for multifamily housing.

Jurisdictions should carefully review limitations on the number of sleeping units in co-living buildings, whether under the name "co-living" or another term. For example, one Washington jurisdiction defines "rooming house" as "a dwelling, with a central kitchen and with more than one but fewer than nine boarders, with no more than nine sleeping rooms." Since multifamily uses do not have an equivalent limit on the number of units in zones that allow rooming houses (using the 4:1 ratio), this definition should be amended, replaced or clearly defined as a use in zoning areas which would not be subject to RCW 36.70A.535.

Sleeping Units

Sleeping Unit Definition

The International Building Code (IBC) defines a "sleeping unit" as "A single unit that provides rooms or spaces for one or more persons, includes permanent provisions for sleeping and can include provisions for living, eating and either sanitation or kitchen facilities but not both. Such rooms and spaces that are also part of a dwelling unit are not sleeping units."[5]

A sleeping unit is a standalone bedroom and does not have the full features of a dwelling unit. Unlike dwelling units, sleeping units are not required to have closets, bathrooms or kitchens. However, most new co-living

[5] 2021 International Building Code, Section 202 Definitions.

developments include private bathrooms and kitchenettes because they are popular with tenants and some building managers find shared bathrooms challenging to manage.

Sleeping units are different from "efficiency dwelling units" under the IBC. These units, which are also known as "studio apartments", are required to have a closet, full bathroom, kitchen sink, cooking appliance, and refrigerator. Efficiency dwelling units have a defined minimum size of 190 square feet.

The IBC does not limit the number of sleeping units that may share a kitchen and sanitation facilities (bathrooms). Any local limits on the number of unrelated people who share a co-living sleeping unit should be based on occupant load per square foot or generally applicable health and safety provisions as established by applicable building code or city ordinance, per RCWs 35.21.682, 35A.21.314, and 36.01.227.



Sleeping unit interiors. Left. Courtesy of Natural and Built Environments, LLC. Right. Courtesy of Neiman Taber Architects.

Room Dimensional Standards

RCW 36.70A.535(2)(a) prohibits jurisdictions from requiring co-living housing to *"Contain room dimensional standards larger than that required by the state building code, including dwelling unit size, sleeping unit size, room area, and habitable space."*[6]

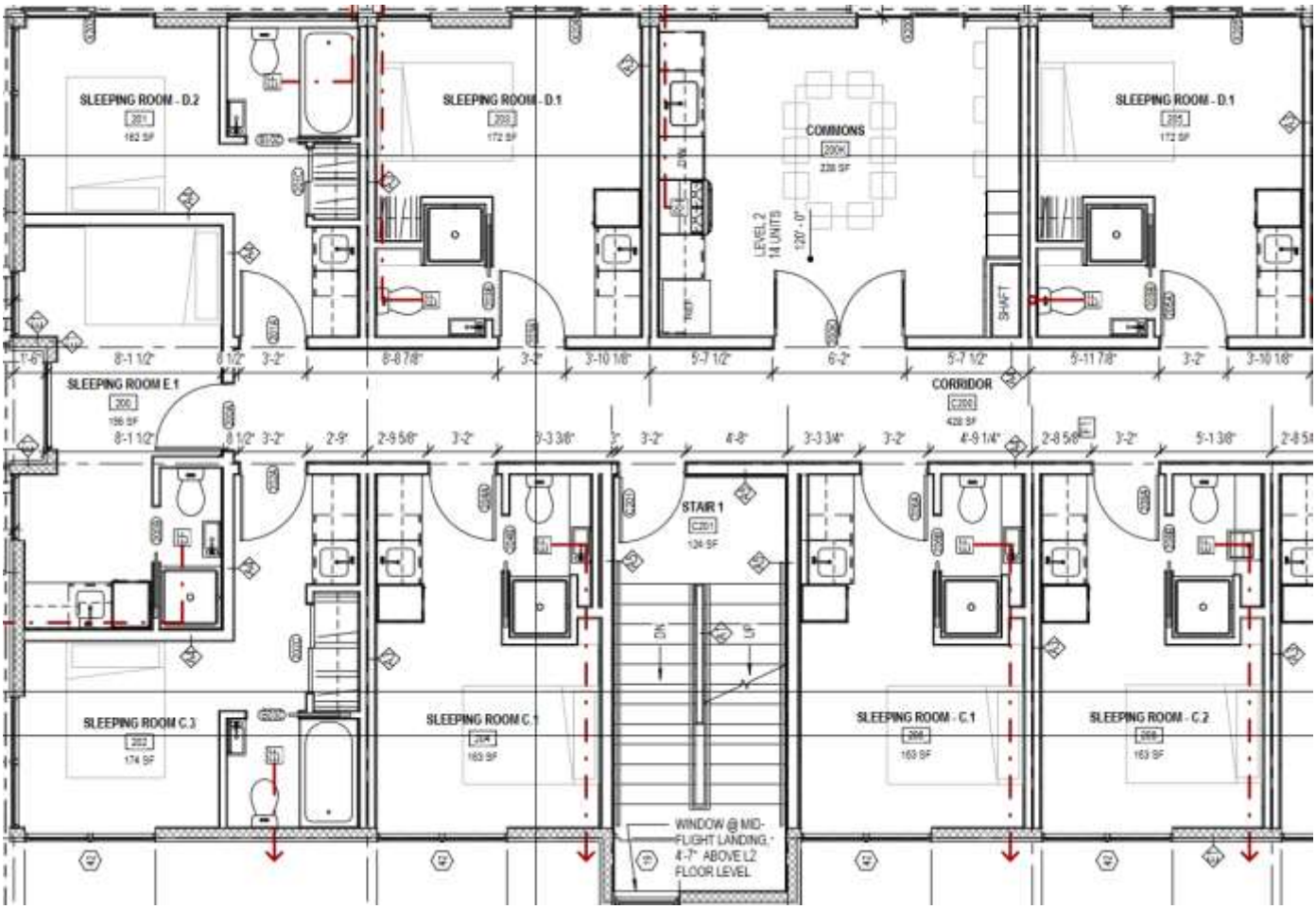
The 2024 IBC definitions and minimum dimensions are as follows:[7, 8]

- Habitable space means "A space in a building for living, sleeping, eating or cooking. Bathrooms, toilet rooms, closets, halls, storage or utility spaces and similar areas are not considered habitable spaces." Habitable spaces other than kitchens must not be less than seven feet in any plan dimension.
- Dwelling unit means "A single unit providing complete, independent living facilities for one or more persons, including permanent provisions for living, sleeping, eating, cooking and sanitation." Dwelling units have a total minimum size of 190 square feet of habitable space and must have at least one room that is a minimum of 120 square feet. Kitchens are not required to be of a minimum floor area.
- Sleeping units must have a minimum size of 70 square feet. For reference, this comfortably fits a twin-size bed.

[6] As of this writing the state building code has the same minimum dimensions as the 2024 International Building Code. See Washington Administrative Code 51-50-1208, Section 1208-Interior space dimensions. https://app.leg.wa.gov/WAC/default.aspx?cite=51-50-1208.
[7] 2024 International Building Code, Section 202 Definitions.
[8] 2024 International Building Code, Section 1208 Interior Space Dimensions.

- Bedroom means "Any room or space used or intended to be used for sleeping purposes in either a dwelling unit or a sleeping unit."[9] A bedroom has a minimum size of 70 square feet when intended for use by one occupant and 100 square feet when intended for use by two occupants, plus another 50 square feet per additional occupant.[10]

The building code has no maximum size for sleeping units. A unit larger than 190 square feet may be considered a sleeping unit if it conforms to the definitions noted above. Cities and counties may adopt a maximum size for sleeping units. A maximum sleeping unit size of 300 square feet would reflect typical sleeping unit sizes in co-living buildings, with a bathroom, closet and/or kitchenette (see co-living examples in Appendix A).



Excerpt of a floor plan from The Kärsti co-living housing development in Seattle, showing sleeping units with private sanitation facilities and kitchenettes and a common kitchen and dining room. Image courtesy of Neiman Taber Architects.

Sleeping Units vs. Dwelling Units

The density and parking calculations provided by RCW 36.70A.535 apply to sleeping units, not small dwelling units such as studio apartments. The table below is an example of how a local jurisdiction can distinguish between sleeping units and dwelling units based on the unit size and the inclusion of certain features.

[9] 2021 International Property Maintenance Code, Section 202 General Definitions.
[10] 2021 International Property Maintenance Code, Section 404.4.1 Room area.

Sanitation (bathroom) and kitchen facilities are not defined by the IBC and the definitions noted in the table are provided as examples. There must be at least one shared kitchen facility for sleeping units to be considered co-living housing, per RCW 36.70A.535(11)(a).

Example definitions:

- Sanitation facilities consist of at least a sink (not shared with kitchen), toilet, and shower and/or tub.
- Kitchen facilities are a room or space used for cooking or the preparation of food with all of the following: sink (not shared with sanitation facilities), 220-volt or natural gas stovetop with ventilation, refrigerator, and food preparation area. Portable or countertop appliances are not part of kitchen facilities.

In the Puget Sound area, many new co-living developments include private bathrooms and kitchenettes. A kitchenette does not meet the definition of a kitchen. It has limited cooking facilities such as a sink, small one- or two-burner electric stove, microwave, and mini-fridge. It might also include adequate counter space for plug-in electric cooking appliances.

Jurisdictions should review their zoning and building codes and may develop local interpretations, provided local interpretations and regulations are consistent with the requirements of RCW 36.70A.535 and the Washington State Building Code.

	Minimum size under state building code	Sanitation facilities (i.e. bathroom)	Kitchen facilities
Sleeping unit	70 square feet	In-unit bathroom optional.* Must have access to shared bathroom **if** in-unit bathroom is not provided.	In-unit kitchen optional* Must have access to shared kitchen.
Dwelling unit	190 square feet **	In-unit bathroom required.	In-unit kitchen required.
* Sleeping unit may not have both private sanitation and kitchen facilities, however kitchenettes may be allowed. ** Cities and counties may adopt a larger minimum size for dwelling units.			

Mix of Unit Sizes an Option, Not a Requirement

RCW 36.70A.535(2)(b) prohibits jurisdictions from requiring co-living housing to "Provide a mix of unit sizes or number of bedrooms." Developers may choose to combine co-living sleeping units and full-feature dwelling units in the same building. In such configurations, all residents are typically given access to co-living common areas.

Common Areas

Shared spaces are essential to the concept of co-living. These may include common kitchens, bathrooms, lounge/social rooms, fitness rooms, libraries, workshops, and similar amenities. Only shared kitchens are

required in order to meet the statute's definition of co-living. When designing common areas, developers consider market demand and how to make their buildings competitive for tenants.

Cities can place standards on the provision of common areas as long as these are not more restrictive than standards for other multifamily development. For instance, a city may require one common area for each eight sleeping units, or ten square feet of common space for each 100 square feet of sleeping unit. Such common areas could be counted towards minimum required open spaces (as some codes allow indoor spaces to qualify for some or all open space requirements). Also see Section 2.5 for more information on open space standards.



Examples of common areas. Clockwise from upper left: lounge and common kitchen in the Kärsti, Seattle WA, courtesy of Neiman Taber Architects. Lounge and laundry room in the Yobi in Seatle, WA, courtesy of Neiman Taber Architects. Common kitchen and lounge in Plaza Apartments in Kirkland, WA, courtesy of Natural and Built Environments, LLC.

Shared Kitchens

Shared kitchens are required in order to meet the statutory definition of co-living. The law has no specific requirements for shared kitchens. In addition to the other co-living requirements described in this section, at least one shared kitchen must be provided in a development for it to be classified as a co-living use under RCW 36.70A.535.

The specific size or quantity of shared kitchens in a co-living development should not be regulated if the same kind of regulation is not applied to multifamily development. Developers have found that tenants can meet their daily needs with in-unit plug-in appliances and kitchenettes. As a result, modern co-living buildings tend to

have only a few shared kitchens that are large enough to host gatherings – for example, one kitchen per 15-20 sleeping units and typically no more than one kitchen per floor. Building owners have found that shared kitchens and other common areas often facilitate social activity like game nights and group dinners.

Utility Functions

Developers report that laundry appliances are typically provided at a ratio of 10-15 sleeping units per set. The building design determines whether laundry appliances are spread throughout a building or centralized in a laundry room. One developer reported that private storage units are lightly used.

2.4 Off-Street Parking Standards

State Law

Basic Requirements

Off-street parking requirements for co-living housing are subject to the following standards:[11]

- A maximum of 0.25 off-street parking spaces per sleeping unit may be required.
- No off-street parking may be required within one-half mile walking distance of a major transit stop (see Major Transit Stop specifications below).

Co-living residents tend to produce fewer vehicle trips than the general population due to proximity to transit and services, and reduced car ownership.[12, 13]

Exceptions

The above off-street parking requirements do not apply:

- If a city or county submits to the Department of Commerce an empirical study prepared by a credentialed transportation or land use planning expert that clearly demonstrates, and the department finds and certifies, that the application of the parking limitations will be significantly less safe for vehicle drivers or passengers, pedestrians, or bicyclists than if the jurisdiction's parking requirements were applied to the same location.[14]
- To portions of cities within a one-mile radius of a commercial airport in Washington with at least 9,000,000 annual enplanements.[15]

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[11] RCW 36.70A.535(3)
[12] A transportation analysis of a mixed apartment and co-living housing project in downtown Kirkland with 290 total units estimated 64 peak hour vehicle trips based on industry standards. A post-occupancy analysis found the project had 33 peak hour vehicle trips. The report concluded this resulted from site management of resident parking and the area's transportation options available to residents.
[13] Another mixed-use co-living development in Kirkland was approved for reduced minimum parking at 0.5 parking spaces per sleeping unit, for a total of 255 provided parking spaces. This was 155 spaces less than would have been required by previous code, and a one-year post-occupancy analysis found the project was 45 spaces over-supplied.
[14] See the Department of Commerce Empirical Parking Study Guidance: https://www.commerce.wa.gov/growth-management/housing-planning/middle-housing/
[15] This only applies to Seattle-Tacoma International Airport. Enplanement data is provided by the Federal Aviation Administration: https://www.faa.gov/airports/planning_capacity/passenger_allcargo_stats/passenger. Jurisdictions applying this exemption should base the one-mile radius on airport passenger facilities.

Major Transit Stop

Off-street parking cannot be required for co-living housing within one-half mile walking distance of a major transit stop. "Major transit stop" is defined by RCW 36.70A.535(11)(b):

"Major transit stop" means:

(a) A stop on a high capacity transportation system funded or expanded under the provisions of chapter 81.104 RCW;
(b) Commuter rail stops;
(c) Stops on rail or fixed guideway systems, including transitways;
(d) Stops on bus rapid transit routes or routes that run on high occupancy vehicle lanes; or
(e) Stops for a bus or other transit mode providing actual fixed route service at intervals of at least 15 minutes for at least five hours during the peak hours of operation on weekdays.[16]

This definition is identical to that for accessory dwelling units, under RCW 36.70A.696(8). This term is slightly different than the general definition of major transit stops under RCW 36.70A.030(26). For more information on how to identify major transit stops and measure distance, see Appendix B.

Local Policy Choice

Eliminating Off-Street Parking Requirements

The cost of providing surface parking can significantly increase the per-space construction cost of co-living housing, depending on the type of parking, number of stalls required, drive aisle area, and turnaround space.

Eliminating minimum off-street parking requirements may encourage co-living development by reducing the cost and physical complexity of projects. This may be particularly beneficial for infill development. Off-street parking requirements often affect the number of units that can be constructed in a co-living housing project, and can significantly impact a project's feasibility. Builders can continue to include off-street parking to meet market demand, even without regulatory requirements.

Eliminating off-street parking requirements for co-living housing is particularly appropriate for areas well-served by local transit service, connected to bike and pedestrian infrastructure, and proximate to job centers.

Bicycle Parking Requirements

Bicycle parking is not addressed in RCW 36.70A.535. If a jurisdiction requires bicycle parking based on the number of vehicle parking spaces, the co-living calculation for 0.25 vehicle parking spaces per sleeping unit will reduce the amount of bicycle parking required. However, if bicycle parking is based on number of sleeping units no reduction is required.

References

- City of Olympia, WA Ordinance 7366 (2023) reduces parking minimums for all residential units
- *A Business Case for Dropping Parking Minimums*, 2022, Planning Magazine
- Parking Reform Network

[16] RCW 36.70A.535(11)(b)

2.5 Other Standards

Bulk Standards

Co-living buildings can range from the size of a single-family home house to a full-sized apartment building.

RCW 36.70A.535(4) and (5) state:

> *"(4) A city or county may not require through development regulations any standards for co-living housing that are more restrictive than those that are required for other types of multifamily residential uses in the same zone."*
>
> *(5) A city or county may only require a review, notice, or public meeting for co-living housing that is required for other types of residential uses in the same location, unless otherwise required by state law including, but not limited to, shoreline regulations under chapter 90.58 RCW.*

This means that co-living housing must be subject to zoning dimensional standards that are equal or less restrictive than those for multifamily uses in the same zone. This includes, but is not limited to, the following types of standards: building height, setbacks, lot coverage, floor area ratio, lot area and lot dimension, impervious surface, open space, and landscaped area standards.



Bulk, height, coverage, and other standards for co-living housing must be no more restrictive than standards for multifamily housing. Pictured: co-living and multifamily housing in downtown Redmond. Source: MAKERS

Jurisdictions should review their codes for any supplemental use standards related to spacing, distribution, buffering, and other location restrictions for co-living housing. Under RCW 36.70A.535(4), such standards should not create a greater restriction on the permitted location of co-living housing compared to multifamily housing in the same zone. For example, a requirement for co-living housing to not be on adjacent lots, or to be separated by 500 feet, is not consistent with the law.

See Section 3.2 Conversion Projects for bulk standards requirements related to conversions.



Example of multifamily building with facade articulation. Source: MAKERS

Design Standards

Co-living housing should be subject to equal or less restrictive design standards than other multifamily uses, per RCW 36.70A.535(4).

Jurisdictions should give special consideration to design standards based on the size of dwelling units, such as articulation standards or minimum balcony sizes. These standards may need to be adjusted or interpreted differently as they are applied to co-living housing, as sleeping units are smaller and not the same as dwelling units. For example, a façade articulation standard that says, "the maximum façade width without articulation shall be no greater than the width of a

unit", could be amended to a specific dimension instead. See Section 3.2 Conversion Projects for design standards requirements for conversion projects.

Open Space Standards

Some jurisdictions require a minimum useable open space or amenity area per dwelling unit, often scaled to the size of dwelling unit or number of bedrooms (studio, one-bedroom, two-bedroom, etc.). Stakeholders report that sleeping units typically accommodate a single resident, so applying per-unit open space standards to these units can result in disproportionate requirements which reduce the feasibility of co-living housing development.

RCW 36.70A.535 does not have specific provisions related to open space standards. Jurisdictions have several options for updating multifamily open space standards to support co-living feasibility:

- Create a reduced open space requirement for sleeping units. For example, apply one-quarter or one-half the open space requirement for co-living that apply to studio apartments.
- Apply an alternate open space standard that does not rely on the size or quantity of units. For instance, require a certain amount of open space for each 1,000 square feet of residential net floor area, for multifamily and co-living.

If open space is required, consider allowing indoor common areas to count as open space in addition to traditional outdoor space (courtyards, balconies, roof decks, etc.). Co-living buildings necessarily include a variety of shared indoor spaces and amenity areas, usually including at least shared kitchens and dining rooms. Other shared indoor spaces may include multi-purpose entertainment space, fitness center, movie theater, library, workshop, conference room, and similar amenities that promote shared use and a sense of community. To encourage a balance with outdoor spaces, some jurisdictions allow projects to count only a portion of indoor common area toward minimum open space square footage requirements.

3.0 Additional Considerations

3.1 Affordable Housing

Market-rate co-living housing can provide an affordable housing option without needing to participate in formal affordability programs. Co-living is often the least expensive private market option available in urban markets and can meet the needs of those who might otherwise experience economic displacement or homelessness. Adequate supply of co-living housing may reduce pressure on publicly funded affordable housing and provide housing affordable to lower income residents who might otherwise wait years for subsidized housing.

However, co-living housing must be eligible to participate in formal government programs and receive public funding. RCW 36.70A.535(6) states:

> *"(6) A city or county may not exclude co-living housing from participating in affordable housing incentive programs under RCW 36.70A.540."*

Where incentive programs are adopted, co-living housing developments can provide affordable housing in exchange for density and height bonuses, fee waivers, expedited permitting, and other benefits that are available to multifamily housing (when consistent with the incentive program requirements). Co-living housing

may also be eligible for multifamily tax exemptions (MFTE) when meeting the local requirements adopted under Chapter 84.14 RCW. It may also be eligible for the use of HUD Housing Choice vouchers.[17]

Stakeholders report that even where co-living housing is permitted, some non-profit affordable housing providers do not include it in their portfolio because of operational complexities. There are more shared spaces to maintain and monitor in a co-living building than a traditional apartment building.

3.2 Conversion Projects

Co-living conversions of existing buildings were relatively common in the past when zoning was more flexible. Commerce recommends considering providing flexibility for both commercial-to-residential and residential-to-residential co-living conversion projects. Older office buildings may be particularly good candidates for conversion due to their floor configurations, with pre-existing shared restroom and kitchen facilities. In some communities, developers have found success converting older motels and churches into micro-units and congregate housing.

Another common type of co-living conversion was older large houses converted into small apartments with some shared kitchen or bathroom facilities. Zoning has made conversions of this type largely prohibited in recent decades. Commerce recommends considering these types of conversions.



Left: Co-living may be well suited to office-to-residential conversions. Center: An older converted mansion with a mix of co-living units and dwelling units. Right: Developers have converted older motels into co-living in several eastern Washington cities. Source: MAKERS

New requirement for cities

RCW 35.21.990 and RCW 35A.21.440 require cities (these RCW sections do not apply to counties) to provide regulatory flexibility for conversion projects that are in commercial and mixed-use zones. In summary, these laws state that cities may not:

- Impose a restriction on housing unit density that prevents the addition of housing units at a density up to 50 percent more than what is allowed in the underlying zone.
- Impose parking requirements on the addition of dwelling units or living units added within an existing building.

[17] https://www.hud.gov/sites/dfiles/PIH/documents/HCV_Guidebook_Payment_Standards.pdf see section 2.4.

- Impose permitting requirements on the use of an existing building for residential purposes beyond those requirements generally applicable to all residential development within the building's zone.
- Impose design standard requirements, including setbacks, lot coverage, and floor area ratio requirements, on the use of an existing building for residential purposes beyond those requirements generally applicable to all residential development within the building's zone.
- Impose exterior design or architectural requirements on the residential use of an existing building beyond those necessary for health and safety of the use of the interior of the building.
- Prohibit the addition of housing units in any specific part of a building except ground floor commercial or retail that is along a major pedestrian corridor as defined by the city.

Cities may not require off-street parking for the addition of dwelling units or living units within an existing building.

3.3 Infrastructure Issues

Public works and infrastructure standards that create conditions on development are a "development regulation" subject to RCW 36.70A.535(4) which limits regulations to those no more restrictive than required for other types of multifamily uses. This is supported by the definition of "development regulations" under RCW 36.70A.030.

To comply with RCW 36.70A.535(4), public works and infrastructure development standards cannot be more restrictive for co-living housing than for multifamily residential uses. Co-living sleeping units have been shown to have substantially lower utility use than dwelling units, in part because more than 90 percent of co-living residents are single-person households.[18]

Water and Sewer

Water and sewer utility purveyors (cities, special districts, and private purveyors) should adopt specific standards for co-living buildings, or sufficient flexibility in the application of multifamily standards to adequately serve co-living buildings without requiring construction of excess infrastructure.

Regarding sewer connections specifically, RCW 36.70A.535(8) states: "A city or county may not treat a sleeping unit in co-living housing as more than one-half of a dwelling unit for purposes of calculating fees for sewer connections, unless the city or county makes a finding, based on facts, that the connection fees should exceed the one-half threshold." If utility purveyors have several rates for different types of dwelling units, the rate applied for co-living should be no more than one-half the rate for multifamily dwelling units, or the closest applicable category, such as a hotel. Commerce recommends adopting this co-living sewer connection fee in the adopted fee schedule.

State law does not define "connection fee", but the definition for "connection charge" in RCW 35.92.385(4)(b) may be informative: "…the one-time capital and administrative charges, as authorized in RCW 35.92.025, that are imposed by a utility on a building or facility owner for a new utility service and costs borne or assessed by a utility for the labor, materials, and services necessary to physically connect a designated facility to the respective utility service."

[18] Reported by a co-living developer and building owner during interviews conducted for this guidance.

Fact-based findings that justify sewer connection fees above the one-half threshold may include information such as:

- Existing co-living sleeping units in the jurisdiction or planning area generate a nearly similar or equal amount of sewer demand as dwelling units in the same area.
- A proposed co-living development for which project-specific fees are being calculated has sleeping units that exceed 300 square feet (meaning the sleeping units are nearly the size of the smallest dwelling units available on the market).
- A sewer utility conducts a financial analysis that demonstrates it does not have sufficient alternative funding to bear the costs of labor, materials, and services necessary to physically connect a co-living development to sewer service under the connection fee rate limitation of RCW 36.70A.535(8).

Reduced monthly rates for co-living units are another way to reduce co-living housing costs. For example, King County treats "microhousing" units as 0.35 of a residential customer equivalent (based on a detached single-family residence) for monthly sewer capacity charges.[19]

Cities, counties, and water utilities should consider a similar one-half to one-quarter metric for requirements related to water infrastructure connections and fees.

Impact Fees

RCW 36.70A.535 does not address impact fees. However, jurisdictions must adopt a fee schedule that complies with RCW 82.02.060(1), which states in part: "…The schedule shall reflect the proportionate impact of new housing units, including multifamily and condominium units, based on the square footage, number of bedrooms, or trips generated, in the housing unit in order to produce a proportionally lower impact fee for smaller housing units…". This requirement must be adopted no later than six months after the jurisdiction's next periodic comprehensive plan update required under RCW 36.70A.130.

New guidance by Commerce on impact fees will be published separately.

Some co-living-specific considerations for setting fee rates:

- Co-living sleeping units are smaller than traditional multifamily units, and therefore should have an adjusted fee, depending on the metric for calculating such fees.
- Co-living residents have been found to produce fewer vehicle trips than the general population due to proximity to transit and services and lower rates of car ownership.[20]
- Given limited access to private open space, co-living residents may desire greater access to public parks, open space, and recreation facilities.
- Co-living residents tend to be single adults without school-aged children.

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[19] "About the capacity charge." King County. https://kingcounty.gov/en/dept/dnrp/waste-services/wastewater-treatment/sewer-system-services/capacity-charge/about

[20] See a Parking Analysis Memo for 162TEN, a co-living building in Redmond: https://www.sightline.org/wp-content/uploads/2024/01/20140831_162TEN_Parking-Analysis_Deviation.pdf. See similar reports for two Kirkland projects in the footnotes of Section 2.4.

More information on impact fees is available from the Municipal Research and Services Center (MRSC).[21] Jurisdictions updating impact fees which may affect non-city facility providers (e.g., school districts) should coordinate with those facility providers on impact fee calculations and capital facilities plans.

Electricity

The electricity used per sleeping unit in co-living developments is typically much lower than for dwelling units. Electricity providers and permitting authorities should consider the lower usage needs when requiring installation of infrastructure.

References

- King County Capacity Charge. Example of a utility fee which is graduated based on the size and type of residential dwelling.
- Department of Ecology municipal stormwater permits. Information on what types of stormwater requirements are in place for jurisdictions across the state.

3.4 Design Considerations

There are a few differences and key considerations for co-living design that differentiate it from design for typical multifamily development.

Architectural Finishes

Because co-living sleeping units are compact, each unit can rent at a higher price per square foot than a typical apartment. As a result, developers report being able to include more durable and higher quality and finishes, such as stone countertops and better lighting, in units and in shared spaces. Co-living housing's limited space needs create the opportunity to exchange space for quality, while still maintaining affordability.

Common Space Design

Given the limited private space in each unit, the design of shared spaces, especially kitchens and eating areas, takes on increased importance for resident quality of life. Shared space designs that include features such as sound absorbing acoustic panels and well-designed, adjustable lighting will help create spaces that are more comfortable and inviting for residents. Outdoor open spaces should be designed to provide a range of activities and spaces for individuals and small groups to enjoy.



Ceiling installed acoustic panels in a common area. Photo courtesy of Schemata Workshop.

Sound Proofing

With limited private space and many neighbors, stakeholders noted the importance of sound proofing shared walls and ceilings. Developers are encouraged to go beyond minimum sound proofing requirements in the building code. If jurisdictions modify requirements, such standards must apply equally to co-living and multifamily development.

[21] "Impact Fees." Municipal Research Service Center. https://mrsc.org/explore-topics/planning/land-use-administration/impact-fees

3.5 Short Term Rentals

Short term rental is a business model in which individual residences are rented out by the owner to customers using an online platform. Some cities restrict short-term rentals in order to support a greater share of the housing stock available for residences; this is especially common in smaller cities and towns with high levels of tourism. Jurisdictions seeking to increase the supply of housing for low- and very low-income households may consider prohibiting short-term rentals in co-living buildings.

3.6 Homeownership

RCW 36.70A.535(11)(a) describes co-living housing as rental housing, stating " 'Co-living housing' means a residential development with sleeping units that are independently rented…"

Co-living housing with sleeping units that are independently owned are not addressed by RCW 36.70A.535. This means ownership co-living housing can be treated differently than the state law requires and may be subject to more restrictive standards for parking, density, and other development regulations.

Jurisdictions may choose to allow owner-occupied co-living housing to be regulated the same as rented co-living housing. This may reduce regulatory barriers for owner-occupied co-living housing and create opportunities for conversion to cooperative ownership. Ownership of co-living housing may be less common than rental co-living housing, but it can be encouraged as an opportunity to promote homeownership for people with low-to-moderate incomes.

3.8 Comprehensive Plans

Integrating Co-Living into Housing Elements

Co-living housing allowed under RCW 36.70A.535 may meet housing needs for low-income households in the 50-80% Area Median Income (AMI) band, and possibly the 30-50% AMI band[22]. Each local jurisdiction will need to verify this finding at the local level. This can be done through a housing needs assessment created for a comprehensive plan or through a market analysis.[23] If no examples of co-living housing are available in your region, it may be appropriate to use data on co-living housing costs from the closest comparable jurisdiction and compare that to local affordability levels (AMIs in the county in which the analysis is being performed).

Allowing for co-living housing in areas that have historically been excluded or in areas where there is evidence of racially disparate impacts will increase affordable housing production, helping meet housing element goals to address past practices and policies that have contributed to racially disparate impacts and exclusion.[24]

Land Use Elements and Land Capacity

For land capacity analysis, consider that assumed densities and potential development outcomes for co-living housing will be different than those that have been observed for multifamily development and mixed-use development. In identifying assumed development rates for land capacity analysis, consider incorporating

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[22] Per RCW 36.70A.070(2), jurisdictions are required to identify sufficient capacity of land for housing affordable at these income levels, and to make adequate provisions for these populations' housing needs.
[23] See the Department of Commerce's Guidance for Updating Your Housing Element, specifically Steps 3.1 and 3.2 on pages 35-37.
[24] See the Department of Commerce's Guidance to Address Racially Disparate Impacts.

information about local market conditions and real estate market dynamics. Additionally, RCW 36.70A.535(8) requires that sleeping units be calculated as not more than one-quarter (¼) for purposes of calculating dwelling unit density. Although co-living housing may yield higher densities of housing units than other housing typologies, tracking any assumptions and rationale used for assumed densities will be helpful.

Not all sites that are zoned for co-living housing will develop or redevelop as co-living housing. In addition to sites needing appropriate zoning for development, co-living housing also needs:

- Physical and financial feasibility
- Developers who are familiar with building co-living housing
- Sites with a willing seller
- Access to financing
- Sufficient demand for co-living housing at a particular location

To determine local viability of co-living, consider researching trends by interviewing developers about the likelihood for developing a co-living product, and evaluating demographics to determine how much demand there is for this housing type. For many communities, it will take a while to identify likely trends in this re-emerging housing typology, so assumptions for co-living development should be modest.

4.0 Resources

Code Examples

- Seattle Council Bill 120822 – Seattle code updates to comply with RCW 36.70A.535, adopted October 2024.

Further Reading

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"Historic South Downtown Oral Histories: Marie Wong Discusses Her Research on Seattle's SRO Hotels and the Men and Women Who Lived in Them". HistoryLink.org, 2015. https://www.historylink.org/File/11135

"Considering SRO Housing in New York City and Beyond." HUD Office of Policy and Research Development, 2018. https://www.huduser.gov/portal/pdredge/pdr-edge-trending-062518.html

Oregon House Bill 3395, Section 17 (2023). Requires local governments within an urban growth boundary to allow the development of single room occupancy (SRO) housing.

APPENDIX A: Co-Living History and Benefits

What is Co-Living?

State law defines co-living housing as:

> *"Co-living housing" means a residential development with sleeping units that are independently rented and lockable and provide living and sleeping space, and residents share kitchen facilities with other sleeping units in the building. Local governments may use other names to refer to co-living housing including, but not limited to, congregate living facilities, single room occupancy, rooming house, boarding house, lodging house, and residential suites.*[25]

Co-living housing goes by many names. In addition to the congregate living facilities, single room occupancy (SROs), rooming house, boarding house, lodging house, and residential suites, noted in the statute, it may also be referred to as micro-units, dormitories, or some other term.

Co-Living Evolution

Twentieth Century Legacy

Co-living, under various names, has a long history in American cities and towns going back to pre-revolutionary times.[26, 27] By the early 1900's, in some major cities it represented as much as ten percent of the rental housing stock, providing a popular housing and lodging option for industrial workers, travelling salesmen, the elderly, young adults, and writers and artists.[28]



Left. The historic Wilson Hotel building, built 1890, is now managed by the Anacortes Housing Authority and functions as co-living housing with ground floor commercial businesses (source: MAKERS). Middle: The Upton Hotel in Spokane, built in 1910 and now known as the Grand Coulee Apartments, is listed on the National Register of Historic Places (Source: Will Maupin, CC BY-SA 4.0). Right. Milwaukee Hotel is one of several SROs still in operation in Seattle's Chinatown International District neighborhood. (Source: MAKERS)

[25] RCW 36.70A.535(11)(a)
[26] "The Hotel Spirt", Slate. https://slate.com/business/2022/07/hotels-rental-market-housing-prices-shortage-solution.html
[27] "Microunits: A Tool to Promote Affordable Housing" in *Retooling Metropolis.* Armlovich, Alex. Manhattan Institute, 2016.
[28] "The Rich American Legacy of Shared Housing." Bloomberg, 2023. https://www.bloomberg.com/news/features/2023-05-02/a-visual-history-of-single-room-occupancy-sro-affordable-housing

Co-living establishments served people with a wide range of incomes and stages of life. Grander "hotels" offered centralized service perks like cleaning, meals, and laundry at the fraction of a cost of maintaining a larger home. More economical lodging houses, including those run by non-profit operators like the YMCA and Salvation Army, provided basic accommodations affordable to those who had fallen on hard times. With minimal private space available to them, co-living residents relied upon and patronized a rich variety of restaurants, small groceries, music halls, reading rooms, and night clubs, which was foundational to early and mid-20th century American urban culture.[29]

As Americans' economic opportunities, travel habits, and values shifted in the post-war period, co-living lost prominence and importance. Identifying safety problems and poverty associated with older co-living properties, urban reformers across the country enacted more stringent regulations that made it more expensive to operate and used zoning to prevent the creation of new co-living buildings.[30] Government led-efforts to demolish existing co-living buildings for "slum clearance", along with gradual decay of older buildings, reduced the number of remaining pre-WWII co-living buildings, now most commonly referred to as single-room occupancy hotels or "SROs". By the 1980's, most co-living housing stock in major cities was demolished or converted to other uses, while public housing and subsidized apartments were not built at a large enough scale to replace the gap in affordability left by co-living, contributing to rising urban homelessness. In response, new policies were passed to preserve existing SROs, even as creation of new co-living buildings remained illegal.

New Beginnings

Starting in the 2000's some developers in the Seattle area noted rising housing costs that created the need for new low-cost apartments in desirable neighborhoods. These developers explored flexibility in Seattle's zoning regulations for congregate housing, i.e. small sleeping units with shared kitchens. From 2009 to 2015 they built thousands of congregate housing "micro-units", targeted at young renters, recent arrivals, and students. This new housing option provided an affordable alternative as overall housing prices continued to spike, but also incited a strong backlash concerned about livability and neighborhood impacts. After code changes around 2015 tempered Seattle's micro housing boom developers continued to seek out opportunities in for new co-living in Redmond, Kirkland, commercial zones in Seattle (where congregate housing was still allowed), and other cities.[31] Developers have also explored conversions of older motels into micro-units in cities around the state in recent years.



Example of early 2010's congregate housing in Seattle. Source: MAKERS

The design of this new co-living housing has evolved considerably from twentieth century models, with contemporary architectural styles and amenities, as illustrated in the examples below.

[29] *New Homeless and Old*. Hoch, Charles, and Slayton, Robert A. Temple University Press, 1989.
[30] "Rooming Houses: History's Affordable Quarters." Sightline Institute, 2012. https://www.sightline.org/2012/11/14/rooming-houses-historys-affordable-quarters/
[31] "When is Seattle Going to Fix Micro-Housing?" Sightline Institute, 2021. https://www.sightline.org/2021/02/04/when-is-seattle-going-to-fix-micro-housing/

Co-living Examples

While some older pre-zoning co-living buildings survive, modern co-living buildings have been built in Washington cities in the past two decades, marketed as micro-studios, micro-units, congregate apartments, eco flats, residential suites, or with the brand name “aPODments”. Examples showing the range of scale and form these buildings take are included below.



The Kärsti
Seattle, 2020
52 co-living units + 334 sf commercial space
Co-living unit size range: 187-276 sf
Lot size: 5,000 SF
Parking: zero off-street parking
Mixed-use income-restricted (MFTE) congregate apartments built in one of Seattle’s mixed-use zones.
Photo courtesy of Neiman Taber Architects



Arete Apartments
Kirkland, 2015
228 co-living units, 52 dwelling units, and 7,200 sf commercial space
Co-living unit size range: 185-286 sf
Lot size: 62,220 SF (two parcels)
Parking: 255 off-street spaces
Large mixed-use complex incorporating both co-living units and traditional one-, two-, and three-bedroom apartments.
Image courtesy of Natural and Build Environments, LLC



Ramiro’s Place
Seattle, 2014
22 co-living units
Lot size: 3,200 SF
Parking: zero off-street parking
Co-living unit size range: 131-175 sf
One of many micro-unit buildings built in Seattle between 2012-2015 prior to code changes that increased the minimum unit size.
Image source: MAKERS



Tudor Apartments
Remond, 2011
61 co-living units
Lot size: 14,387 SF (nine parcels)
Parking: 30 off-street parking spaces
Co-living unit size range: 222-301 sf
Micro-suite building designed to mimic appearance of townhouses.
Photo courtesy of Natural and Build Environments, LLC

Benefits of Co-Living Housing

As housing in Washington has become increasingly unaffordable, interest in co-living has grown. Co-living housing has many benefits, including:

- Providing market-rate, non-subsidized rental homes affordable to people in the workforce earning as low as 50 percent of area median income (older co-living units in Spokane area cost $350 per month, and in the Puget Sound suburbs some new co-living units are renting for $1,000 per month)
- Offering housing options for people who want a low-cost, private alternative to living with roommates
- Creating a living arrangement with shared community spaces that facilitate social connections
- Increasing affordable housing options in high opportunity neighborhoods with transportation options
- Reducing energy demand since units are small and new housing can reduce commutes and sprawl

Modern co-living buildings are high-quality and can feature desirable amenities. Stakeholders note that co-living is a great option for seniors looking to downsize their living arrangements and that co-living helps build communities and reduce loneliness for people of all ages. They are especially well-suited for urban infill on narrow lots because the rent per square foot tends to be higher than other multifamily building types.[32] Like any other development, co-living buildings must comply with all building, fire, and life safety codes.

For these and other reasons, co-living is an effective way to help accommodate housing needs for the state's growing population. For more information, see the Legislature's findings in the notes section of RCW 36.70A.535 under "Intent—Findings—2024 c 180."

Messaging

While once common, it has been decades since co-living uses like SROs and boarding houses were widely permitted in most cities. Planners in jurisdictions implementing RCW 36.70A.535 may encounter members of the public and elected officials with questions about the legislative requirement to re-introduce and allow co-living as a permitted use in on lots that allow at least six multifamily residential units.

RCW 36.70A.535 provides the framework for regulating co-living, including where co-living must be a permitted use and limitations on jurisdictions regarding how certain development standards may be applied. Planners and public officials do have an important role to play in public communication and education about co-living and the residents who may live in co-living units, including why the State legislation was passed. In addition to the benefits of co-living identified above, planners and public officials should review the points below and consider incorporating them in public facing materials on co-living.

Framing Discussion of Co-Living

- Allowing co-living housing implements a state requirement and offers one more housing option to achieve the statewide housing needs projection developed by Commerce for 1.1 million homes over the next 20 years.
- Co-living is a way for the private market to take pressure off publicly-subsidized affordable housing. More than a third of Washington households are housing cost-burdened, meaning they pay more than 30% of

[32] "The Macro View on Micro Units," Urban Land Institute, 2014.

their income in housing costs, and there isn't nearly enough income-restricted affordable housing to house everyone who would qualify for it.
- Recently built co-living housing in Kirkland and Redmond is popular with service sector workers, seniors, and young professionals.
- Different types of housing are better suited to people at different stages of life, and in different types of employment. A broad range of housing options can also help people adjust to abrupt changes in income or family status.
- Shared living spaces like common kitchens and dining areas encourage social interaction between residents.
- The building code places well-vetted minimum standards on habitable space.
- Co-living housing is environmentally friendly. Co-living housing is generally located near destinations, allowing residents to drive less. Small units with shared walls require less energy to heat and cool.

The following resources may be shared with members of the public and elected officials who want to learn more about co-living housing.

- FAQ: Co-living for Washington State, Sightline Institute, 2023
- America Redux Excerpt: The Rich American Legacy of Shared Housing, Bloomberg Citylab, 2023
- Cruel Musical Chairs (or Why Is Rent So High?), Sightline Institute, 2017
- Micro-apartments are back in Seattle after disappearing decades ago, Seattle Times, 2024
- Why some Seattle area seniors are choosing dorm-sized apartments, KUOW, 2024
- Additional videos and informational materials in English, Chinese, and Spanish are available at the Department of Commerce Housing Planning webpage.

Resources for public engagement strategies:

- STEP Messaging Guide, Department of Commerce, 2024. Note: while STEP is different from co-living, the strategies described may also be useful for communicating about co-living.
- "You Don't Have to Live Here" Why Housing Messages are Backfiring and 10 Things We Can Do About It, Frameworks Institute, 2016
- Building Support for Affordable Homeownership and Rental Choices, Center for Housing Policy, 2013
- How Does Affordable Housing Affect Surrounding Property Values? Housing Synthesis Research Project, 2008.
- Myths and Facts about Affordable & High Density Housing, California Planning Roundtable, 2002

Internal Staff Engagement

Co-living regulations touch on multiple departments within a jurisdiction. Staff in other departments whose work involves permitting and development review may be unaware or not well informed about the requirements of RCW 36.70A.535 and benefits of allowing co-living housing in multifamily zones.

It is important to pro-actively communicate with other department staff about the jurisdiction's obligation to incorporate co-living into the multifamily permitting procedures. To help address potential issues, focused staff workshops and mock pre-application meetings can be highly valuable. For example, in anticipation of allowing middle housing (small multiunit buildings like duplexes and townhouses) in low-density residential zones the City of Shoreline held several mock pre-application meetings to daylight questions, confusion, and inconsistencies in permitting procedures. According to staff, the process helped identify the need for more

specific standards related to fire access and utility fee rates, as we as several provisions outside of the zoning code that needed to be updated. A similar process for co-living could be beneficial.

Some potential questions to review with staff and non-city service providers such as water districts and fire districts:

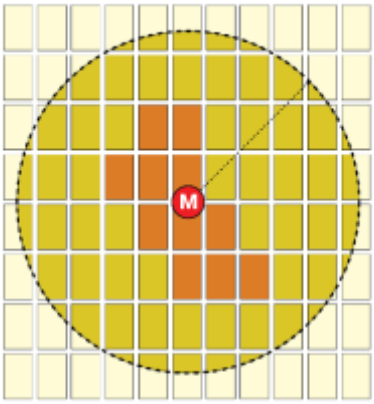
- Are all of those involved in the permit review process aware of the legal requirement to permit co-living buildings?
- What information is needed to review a co-living permit application?
- Are there existing regulations which conflict with co-living, RCW 36.70A.535?
- How does the code address converting dwelling unit-based standards (such as open space square feet per unit) when dealing with much smaller sleeping units?
- Do permit reviewers know if, or how much, parking or usable open space is required?
- Do permit reviewers know the impact fee rate per sleeping unit, and does this accurately reflect likely impacts?
- Are permit reviewers aware that sewer connection fees for co-living are calculated at no more than one-half a dwelling unit, unless findings are made to allow connection fees to exceed the one-half threshold?
- Can the Building Official provide a summary of minimum unit sizes for a sleeping unit?

Do utility providers have the information they need to adequately forecast potential demand from co-living buildings?

APPENDIX B: Parking Near Major Transit Stops

Measuring One-Half Mile Walking Distance

Jurisdictions can measure distances from major transit stops in at least two different ways. Each method comes with advantages and disadvantages. The chosen methodology should be identified in the code, perhaps within a definition of "walking distance", to ensure the methodology is consistently applied and measured over time. Inclusion of the walking distance area on the zoning map, would offer greater certainty to property owners and others as to which parcels are and are not included in the walking distance requirements of a major transit stop. A potential downside to this approach is the need to go through a procedural process to amend the zoning map should the walking distance need to be amended over time due to physical improvements that change the walking distance or routes.



Conceptual illustration of different methods for measuring walking distance. Orange on the map represents a multifamily zone and yellow represents a middle housing zone. Source: MAKERS

For both methods it is important to consider whether to place a center point of the major transit stop or use the perimeter of the major transit stop. In general, separate radii should be drawn for each boarding and alighting point if they are separated by more than 100 feet, such as a north-bound and a south-bound bus stops that are located at opposite ends of a block. For large major transit stops, such as a rail station, the most straightforward approach is to locate center points in the middle of the station platforms. However, the optimal approach should always be determined using the best judgement of the jurisdiction.

Radius, with Adjustments

In this approach, a circle is centered on the major transit stop and the radius of the circle is the required distance. All applicable lots which are fully within the circle should be applicable. Lots which are partially within the circle should also be applicable in order to increase housing capacity near major transit stops, though a jurisdiction can also set other criteria such as at least 50 percent of a lot or a minimum amount of lot area is in the circle for the lot to be included.

This method has the advantage of being easy to execute. A consideration is where precisely the circle is centered for large major transit stops, such as a rail station; the approximate center of the stop or platforms is most straightforward and avoids potential complexities with using pedestrian entrances and property boundaries - however, this should be determined on a case-by-case basis using the best judgement of the jurisdiction.

This method has the disadvantage of not accounting for conditions that can constrain walkability and reduce the actual area that is in reasonable walking distance of the major transit stop, such as terrain, water bodies, missing pedestrian routes, or infrastructure barriers. This disadvantage could be overcome by first drawing the

circle and then customizing and adjusting it to remove areas which are not reasonably in walking distance due to local conditions. Areas which are removed should have documentation explaining why they are exempt.

Path-Finding

In this approach, actual walking paths extending from a major transit stop for the required walking distance are mapped using a geospatial analysis of the local street network and other pedestrian routes such as off-street trails. All lots zoned predominantly for residential use which touch the walking paths are applicable.

This method has the advantage of more accurately capturing lots within actual walking distance of major transit stops.

This method has the disadvantage of requiring access to geospatial analysis software and the skills, funding, and time to employ it. This method also requires that the analysis be repeated from time-to-time to account for changes to pedestrian infrastructure. In some cases, these disadvantages could be overcome by hiring an outside consultant who specializes in geospatial analysis. Network analysis results created for this purpose should be displayed on zoning maps and made available for download on public geographic information system (GIS) databases, if possible.

CITY OF AUBURN WASHINGTON

AGENDA BILL APPROVAL FORM

Agenda Subject:
2024 Downtown Subarea Plan Update (Teague)
Public Hearing for public testimony and Planning Commission deliberation on the 2024 Auburn Downtown Subarea Plan, Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and associated subarea land use map and subarea zoning map amendments.

Meeting Date:
December 2, 2025

Department:
Community Development

Attachments:
Planning Commission Staff Report, PowerPoint Presentation, 2024 Downtown Subarea Plan, Planned Action EIS – Appendix A of Subarea Plan, Baseline Report Final – Appendix B of Subarea Plan, Subarea Land Use Map Amendment, Subarea Zoning Map Amendment, Public Comments & Staff Responses

Budget Impact:
N/A

Administrative Recommendation:
Planning Commission to recommend approval of the 2024 Auburn Downtown Subarea Plan, Subarea Plan & Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and the associated subarea land use map and subarea zoning map amendments.

Background for Motion:

Background Summary:
See attached Staff Report

Councilmember:

Staff: Jason Krum

PLANNING COMMISSION STAFF REPORT

AGENDA SUBJECT/TITLE:
2024 Auburn Downtown Subarea Plan

APPLICANT/AGENT/OWNERS:
City of Auburn

REQUEST:
Planning Commission to hold a public hearing, deliberate, and take action on the 2024 Auburn Downtown Subarea Plan, Subarea Plan & Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and associated subarea land use map and subarea zoning map amendments.

LOCATION:
Downtown Subarea. The updated 2024 Auburn Downtown Subarea Plan (the "2024 Subarea Plan") encompasses approximately 360 acres. This subarea includes the existing Downtown Urban Center (DUC) boundary, but expands to the north to 10th Street NE and 8th Street NE. The BNSF/Sounder rail corridor comprises the western border of the expanded area, while the eastern border is defined by H Street NE, 4th Street NE, and E Street NE.

NOTIFICATION:
Hearing Notice was published in the Seattle Times and posted on the City's Land Use Notice webpage and physically at City Hall and City Hall Annex on November 21, 2025.

HEARING DATE:
December 2, 2025

SEPA STATUS:
Notice of Availability of Draft Environmental Impact Statement (DEIS) and Notice of Public Comment Period and Meeting was issued on September 25, 2024. A Notice of Availability of Final Environmental Impact Statement (Final EIS) was issued on January 22, 2025 and the City did not take action for seven (7) days.

EXISTING LAND USE:
Commercial, Industrial, Mixed Use, Neighborhood Residential Two, and Neighborhood Residential Three

EXISTING ZONING:
C-2, Heavy Commercial, C-1, Light Commercial, R-4, Residential High, R-F, Residential Flex, R-2, Residential Low, M-1, Light Industrial, DUC, Downtown Urban Center

STAFF:
Alexandria Teague, Planning Services Manager, Dept. of Community Development

STAFF RECOMMENDATION: Planning Commission to recommend approval of the 2024 Auburn Downtown Subarea Plan, Subarea Plan & Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and the associated subarea land use map and subarea zoning map amendments.

SUMMARY OF CODE CHANGES: The proposal is a non-project action to replace the 2001 Auburn Downtown Plan and pursue a Planned Action. The most recent version of the Auburn Downtown Plan and EIS was adopted in 2001 and has provided the framework for development of the City's downtown for the past 20 years. The document is now reaching the end of its planning period, and the City has changed over that time. The 2024 Auburn Downtown Subarea Plan is envisioned to replace the existing plan by providing a refreshed perspective of land use, development, and transportation for the downtown area. The 2024 Subarea Plan also includes the implementation of DUC zoning districts and expansion of the DUC land use designation within the subarea, which necessitates an amendment of the City's Land Use Map and Zoning Map, respectively.

FINDINGS OF FACT:

Background Summary:

1. The City of Auburn completed the latest comprehensive plan update in 2024 under Ordinance No. 6960 to comply with the Washington State Growth Management Act (GMA).

2. The downtown area is one of the designated and adopted special planning areas, or subareas, identified in the City's Land Use Element of the Comprehensive Plan.

3. The City of Auburn adopted the most recent version of the Auburn Downtown Plan and Environmental Impact Statement (EIS) in 2001, providing direction for the development of the downtown area over the past 20 years and "2001 Auburn Downtown Plan" set a vision and strategies for a vibrant, compact, mixed-use urban downtown core.

4. While the 2001 Auburn Downtown Plan has been highly successful due to time, financial commitments, and contributions from the community, the City is now ready to plan for the next 20 years.

5. The City of Auburn has prepared a new subarea plan, the "2024 Auburn Downtown Subarea Plan", and a Planned Action Ordinance for the downtown area.

6. The 2024 Subarea Plan provides an updated vision for downtown that encourages more activity, housing, and economic development opportunities, and enhances livability in and around the Subarea.

7. Downtown Auburn (the Subarea) is recognized as a Regional Growth Center (RGC) under Vision 2050 by the Puget Sound Regional Council (PSRC). As an RGC containing a transit station, land use policies and regulations should encourage population and employment growth.

8. The 2024 Subarea Plan satisfies the requirements of GMA for Auburn to plan forecasted growth, and supports the goals of PSRC's Vision 2050 and Transportation 2050 (T2050) regional plans.

Conformance with the Criteria for Plan Amendments (*Criteria in Italics*):

9. *The proposed change will further and be consistent with the goals and objectives of the plan and the plan will remain internally consistent;*

   Staff Response: The Land Use Element, recently updated and adopted under the periodic GGMA update, completed in 2024, anticipated the adoption of a new downtown subarea plan by the end of 2025. The Land Use Element states that the DUC land use designation should be applied exclusively in the downtown subarea. Further the RGC is identified in the Comprehensive Plan and the Comprehensive Land Use Map.

10. *Whether the capacity to provide adequate services is diminished or increased*;

    Staff Response: PSRC forecasts a population increase of about 20 percent for the next two decades in Auburn. The downtown subarea boundary is expanded from 230 acres to approximately 360 acres. This expansion will increase the subareas' capacity to accommodate jobs and housing units as well as accommodate an estimated 62.9 activity units per acre.

11. *Assumptions upon which the comprehensive plan is based are found to be invalid;*

    Staff Response: This criterion is not applicable. No assumptions of the Comprehensive Plan have been found invalid.

12. *A determination of change or lack of change in conditions or circumstances has occurred since the adoption of the latest amendment to the specific section of the comprehensive plan that dictates the need for a proposed amendment;*

    Staff Response: The most recent version of the Downtown Plan and EIS was adopted in 2001 and has provided the framework for development of the City's downtown for the past 20 years. The document is now reaching the end of its planning period. The downtown has changed over the last 20 years. The 2024 Subarea Plan will replace the existing plan.

13. *If applicable, a determination that a question of consistency exists between the comprehensive plan and Chapter 36.70A RCW, the countywide planning policies for either King and/or Pierce County, as appropriate, and Vision 2050;*

    Staff Response: The 2024 Subarea Plan is consistent with GMA, the King and Pierce Countywide Planning Policies, and Vision 2050 as it supports the regional framework for accommodating growth. It satisfies the requirements of GMA for Auburn to plan forecasted growth. One of the compliance measures is for a County (King and Pierce County) to establish countywide planning policies in conjunction with the cities and towns in the county and assign the household unit and employment growth allocations for the cities within its county area (its jurisdiction). The City must accommodate our allocations; Auburn's allocations or targets are19,520 new jobs and 12,212 new housing units by 2044. As an RGC the downtown subarea is anticipated to accommodate approx. 17% of the 19,520 new jobs and approx. 49% of the 12,212 new homes.

The 2024 Subarea Plan also supports the goals of Vision 2050. Vision 2050 provides a regional planning frameworks that support accommodation of forecasted growth in a manner that results in the greatest overall benefits to the Central Puget Sound region. PSRC has designated downtown Auburn as an
RGC , one of 29 locations throughout the region that have key "business, governmental and cultural facilities and are planning for growth." The 2024 Subarea Plan will meet the minimum activity units such that the downtown subarea maintains is regional urban growth center designation.

14. *If the request is to change the land use designation of a specific property on the comprehensive land use map, the applicant must demonstrate one of the following:*

    a. *The current land use designation was clearly made in error or due to an oversight;*

    Staff Response: The current land use designation was not made in error nor an oversight. The existing land use designation has been in place prior to development of the 2024 Auburn Downtown Subarea Plan.

    b. *The proposed land use designation is adjacent to property having a similar or compatible designation, or other conditions are present to ensure compatibility with surrounding properties;*

    Staff Response: The proposed DUC land use designation will support implementation of the 2024 Auburn Downtown Subarea Plan and the DUC zoning districts.

    c. *There has been a change in conditions since the current land use designation came into effect.*

    Staff Response:
    The Land Use Element, recently updated and adopted under the periodic GMA update, completed in 2024, anticipated the adoption of a new downtown subarea plan by the end of 2025. The 2024 Subarea Plan features new zoning districts intended to specify the uses and design standards within the downtown urban center. The DUC zoning districts will implement the DUC land use designation.

Procedural Steps:

15. A scoping notice for the Environmental Impact Statement was issued on October 5, 2022, and the City observed a 21-day comment period. The scoping comment period ended on October 26, 2022.

16. A Notice of Availability of Draft Environmental Impact Statement (DEIS) and Notice of Public Comment Period and Meeting was issued on September 25, 2024.

17. The City held an open house at 6 p.m. PST, on October 15, 2024, at 25 W. Main St., Council Chambers, Auburn, WA, and observed a 30-day comment period, during which no comments were received.

18. A Notice of Availability of Final Environmental Impact Statement (FEIS) was issued on January 22, 2025, and the City did not take action for seven (7) days.

19. Pursuant to Revised Code of Washington (RCW) 36.70A, the 2024 Downtown Subarea Plan and Environmental Impact Statement (EIS) were submitted to the Washington State Department of Commerce on March 14, 2025. The 60-day notice period ended on May 13, 2025.

20. Staff received comments from Commerce on May 14, 2025 related to anti-displacement policies and incorporated those comments in the 2024 Subarea Plan.

21. Pursuant to Revised Code of Washington (RCW) 36.70A, the downtown subarea land use map amendment and zoning map amendment were submitted to Commerce on October 8, 2025.

22. Staff received comments from Commerce on October 21, 2025 regarding the map amendments and no further changes were needed at this time.

23. Staff discussed the 2024 Auburn Downtown Subarea Plan, Subarea Plan & Planned Action EIS (Appendix A), Baseline Report Final (Appendix B), and associated land use map and zoning map amendments with the Planning Commission on August 5, 2025 and October 21, 2025, respectively.

24. ACC 14.22.100 outlines the public hearing requirements by planning commission. Amendments to the Periodic Comprehensive Plan generally comply with "area-wide" requirements.
    - A. *The planning commission shall hold at least one public hearing on all proposed amendments to the comprehensive plan. Notice of such public hearing shall be given pursuant to Chapter 1.27 ACC and, at a minimum, include the following:*
      - *1. For site-specific plan map amendments:*
        - *a. Notice shall be published once in the official newspaper of the city not less than 10 calendar days prior to the date of public hearing;*
        - *b. Notice shall be mailed by first class mail to all property owners of record within a radius of 300 feet of the proposed map amendment request, not less than 10 calendar days prior to the public hearing;*
      - *2. For area-wide plan map amendments:*
        - *a. Notice shall be published once in the official newspaper of the city not less than 10 calendar days prior to the date of public hearing;*
        - *b. Notice shall be mailed by first class mail to all property owners of record within the area subject to the proposed amendment;*
        - *c. Notice shall be posted in at least two conspicuous locations in the area subject to the proposed amendment not less than 10 calendar days prior to the date of the public hearing.*
    - *B. Notwithstanding the above, the director may expand the minimum noticing provisions noted above as deemed necessary.*
    - *C. Planning Commission Recommendation. The planning commission shall conduct a public hearing on all potential comprehensive plan amendments and shall make and forward a*

recommendation on each to the city council. The planning commission shall adopt written findings and make a recommendation consistent with those findings to the city council.

D. The city council, if it elects to amend the comprehensive plan, shall adopt written findings and adopt said amendments by ordinance.

E. State Review. All comprehensive plan amendments considered by the planning commission shall be forwarded for state agency review consistent with RCW 36.70A.106.

F. Any appeal of an amendment to the comprehensive plan shall be made in accordance with Chapter 36.70A RCW.

25. A Notice of Public Hearing (NOH) was issued on October 24, 2025. Pursuant to ACC 14.22.100, the following methods of noticing for the Planning Commission public hearing were conducted:
    a. The NOH was published in the Seattle Times on October 24, 2025.
    b. The NOH was posted in two general public locations (City Hall and City Annex).
    c. The NOH was posted on City's Public Land Use Notice webpage.
    d. The NOH was mailed to all property owners with the expanded subarea boundary.

26. A NOH was re-issued on November 21, 2025. Pursuant to ACC 14.22.100, the following methods of noticing for the Planning Commission public hearing were conducted:
    e. The NOH was published in the Seattle Times on November 21, 2025.
    f. The NOH was posted in two general public locations (City Hall and City Annex).
    g. The NOH was posted on City's Public Land Use Notice webpage.
    h. The NOH was mailed to all property owners with the expanded subarea boundary.

27. Staff received several public comments regarding the map amendments from property owners. The public comments and staff responses are included as Exhibit 7.

28. Planning Commission will hold a public hearing on December 2, 2025 on the 2024 Auburn Downtown Subarea Plan, Appendix A and B, and the associated land use map and zoning map amendments.

EXHIBITS:

1. PowerPoint Presentation
2. 2024 Downtown Subarea Plan
3. Planned Action EIS – Appendix A of the Subarea Plan
4. Baseline Report Final – Appendix B of the Subarea Plan
5. Subarea Land Use Map
6. Subarea Zoning Map
7. Public Comments & Staff Responses

EXHIBIT 1

PLANNING COMMISSION

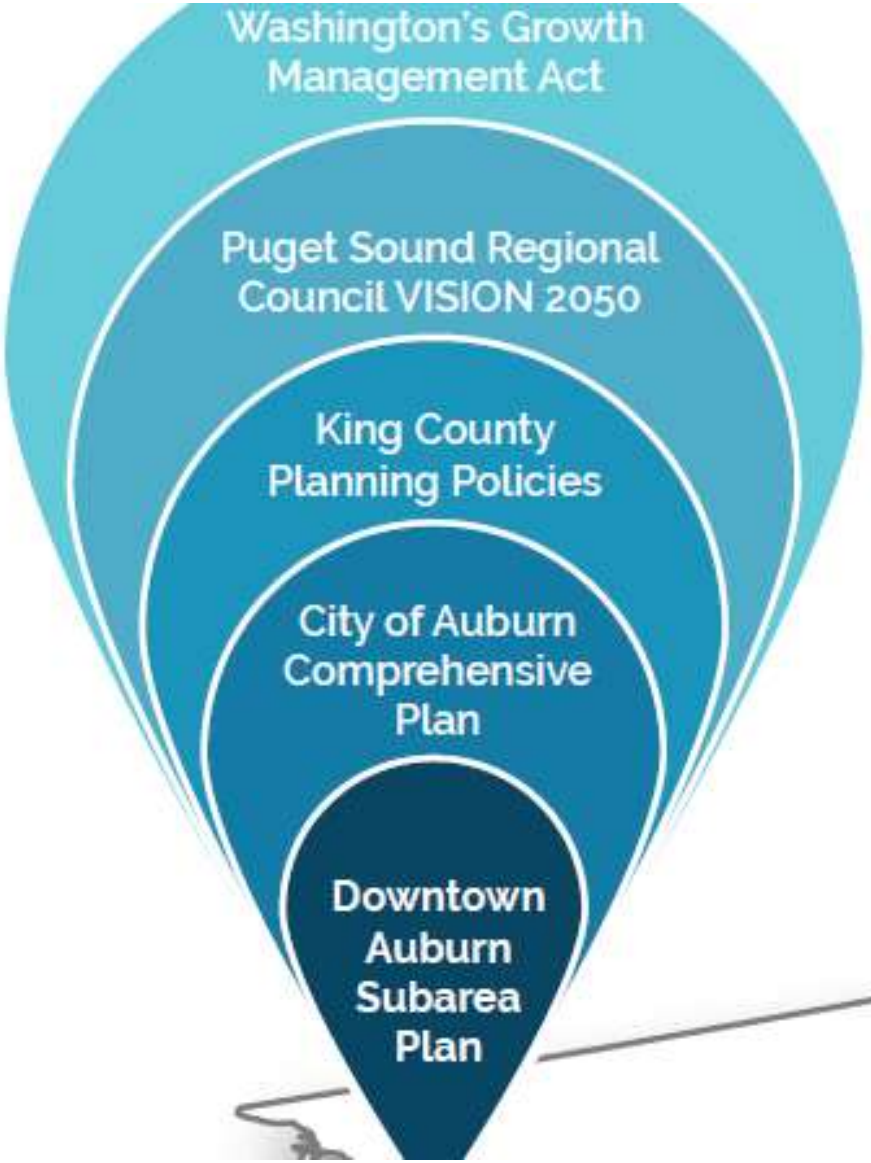
2024
AUBURN DOWNTOWN SUBAREA PLAN

PRESENTED BY
ALEXANDRIA TEAGUE
PLANNING SERVICES MANAGER
DECEMBER 2, 2025

Department of Community Development
Planning • Building • Development Engineering • Permit Center
Economic Development • Code Enforcement

AUBURN VALUES

SERVICE
ENVIRONMENT
ECONOMY
CHARACTER
SUSTAINABILITY
WELLNESS
CELEBRATION



STATUS OF THE PLAN

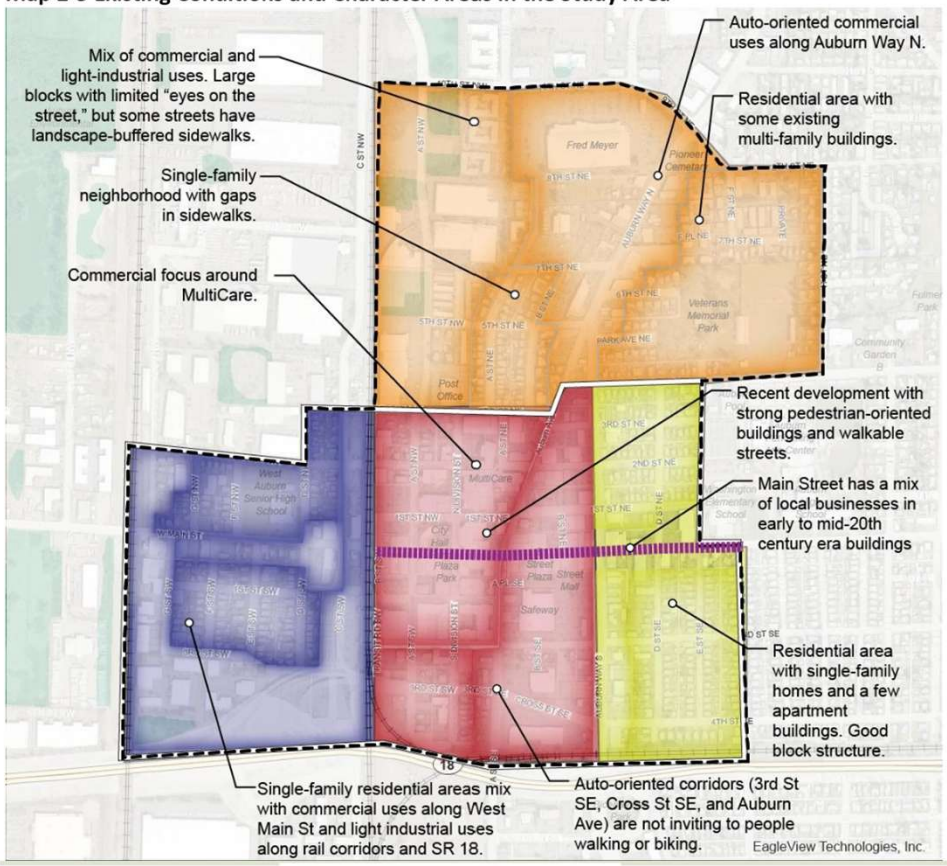
WHAT IS THE DOWNTOWN SUBAREA PLAN?

- Most recent version adopted 2001
- Direction over the past 20 years
- Strong, pedestrian-oriented center
- Plan for the next 20 years



WHAT DOES THE NEW PLAN FEATURE?

Map 2-5 Existing Conditions and Character Areas in the Study Area

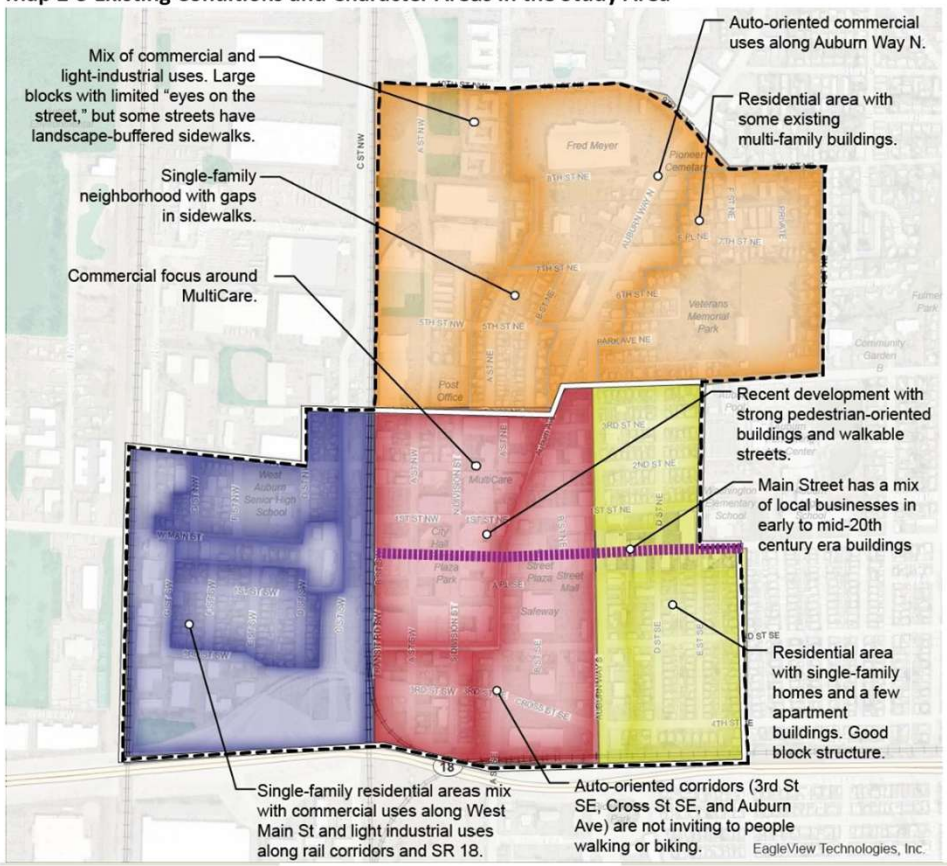


SOURCES: MAKERS (City of Auburn GIS data).

- **Includes key themes:**
  - **Expanding Downtown**
  - **West Downtown**
  - **North Downtown**
  - **Main Street**
  - **Vacant Storefront Policies**

WHAT DOES THE NEW PLAN FEATURE?

Map 2-5 Existing Conditions and Character Areas in the Study Area



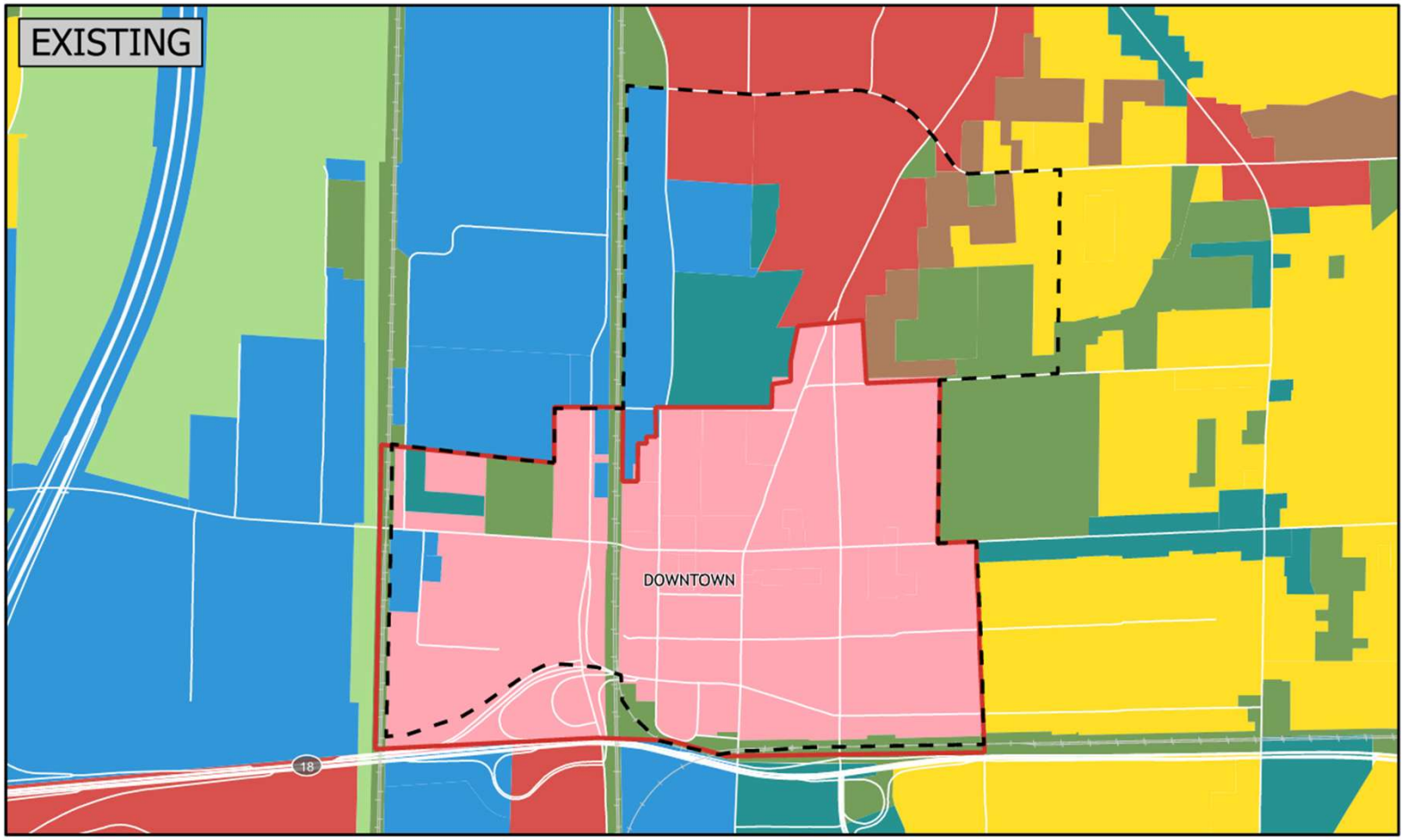
SOURCES: MAKERS (City of Auburn GIS data).

- **Includes key themes:**
  - **MultiCare Hub**
  - **Displacement Risks**
  - **Arts & Cultural Public Investments**
  - **Housing & Affordability**
  - **Increasing Activity**
  - **Thriving Business Center**

PUBLIC ENGAGEMENT

March 2022 - City Council Update	June 2022 - Planning Commission Update	July 2022 - Interviews w/ Large Employers & Property Owners	July 2022 - Interviews w/ Development Comm. & Housing Advocates	July 2022 - Interview with Business Community
August 2022 - Farmer's Market Engagement	Oct. 2022 - Subarea Plan & EIS Scoping Notice Issued	December 2022 - Planning Commission Overview Presentation	Summer 2021 to 2023 - Online Survey	March to Nov. 2023 Comprehensive Plan Presentations - Planning Comm. & City Council
November 2023 - City Council Visioning	April 2023 - Comprehensive Plan Update Open House	Sept. 2024 - DEIS Notice Issued	Oct. 2024 – DEIS Open House held in Council Chambers	Jan. 2025 - FEIS Notice issued

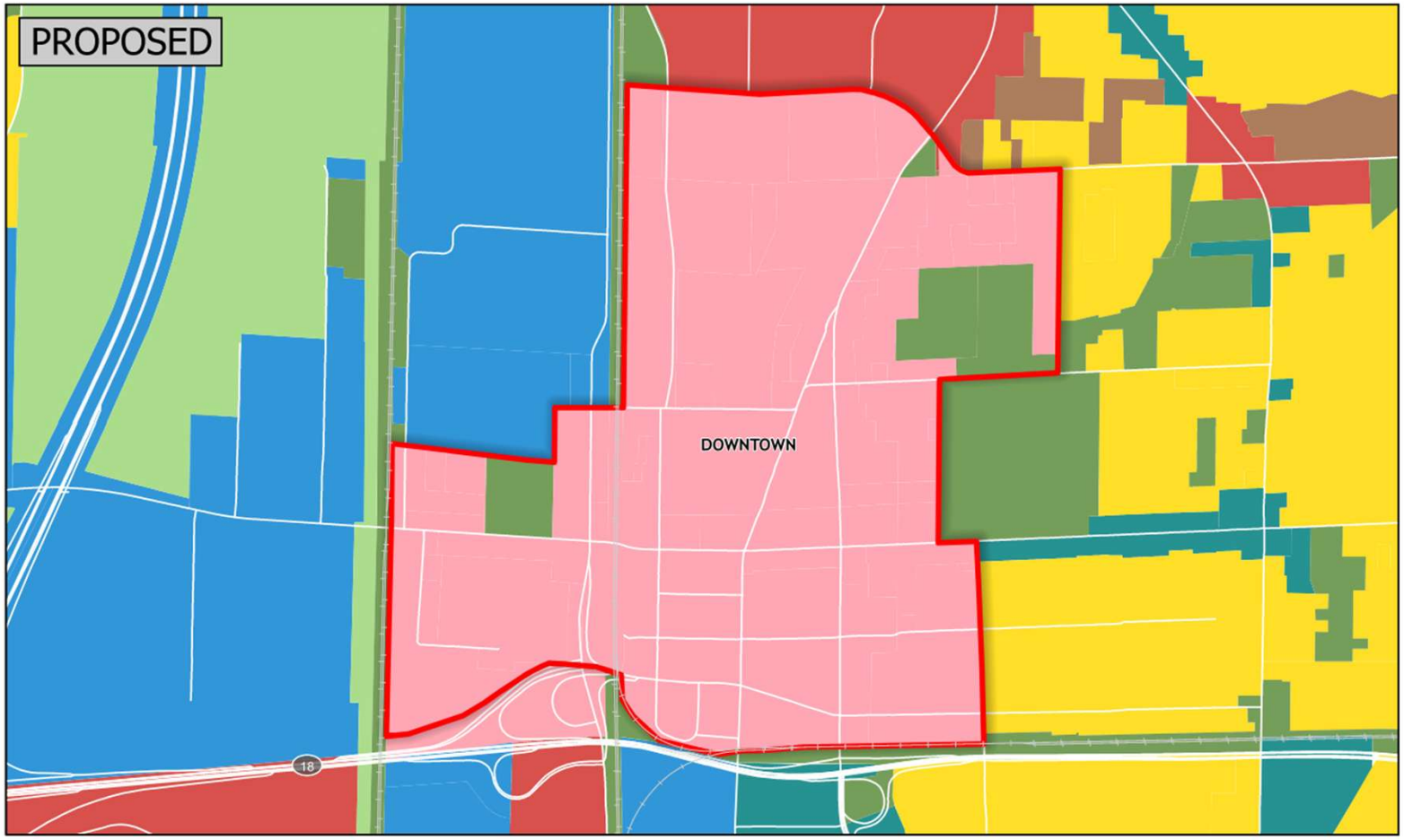
PUBLIC COMMENTS



Ord. No. 6997

- Commercial
- Downtown Urban Center
- Neighborhood Residential Two
- Neighborhood Residential Three
- Open Space
- Public/Quasi-Public
- Mixed-Use
- Industrial
- Existing Downtown Urban Center
- Expanded Downtown Urban Center
- Proposed Downtown Urban Center

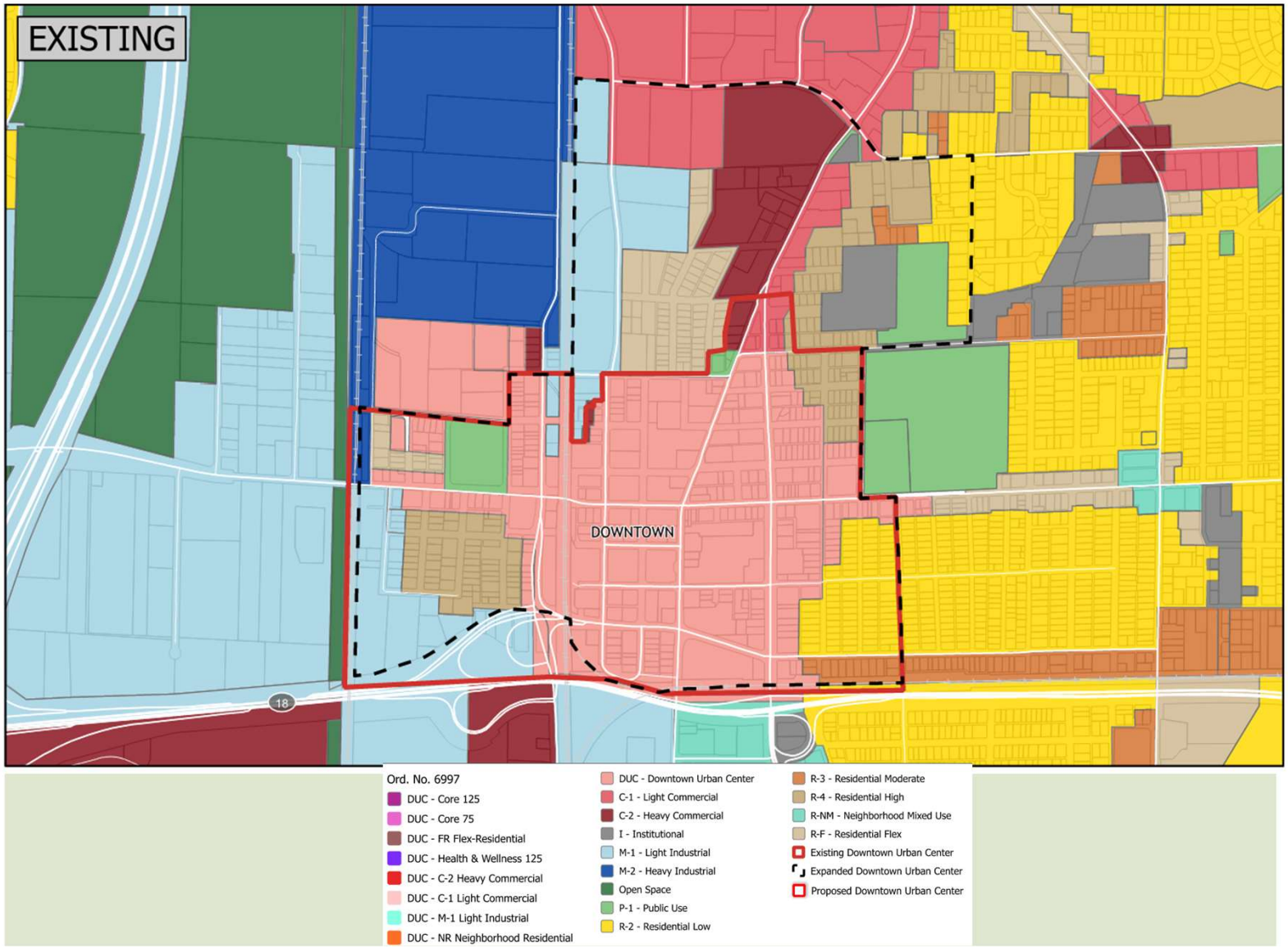
EXISTING LAND USE DESIGNATIONS



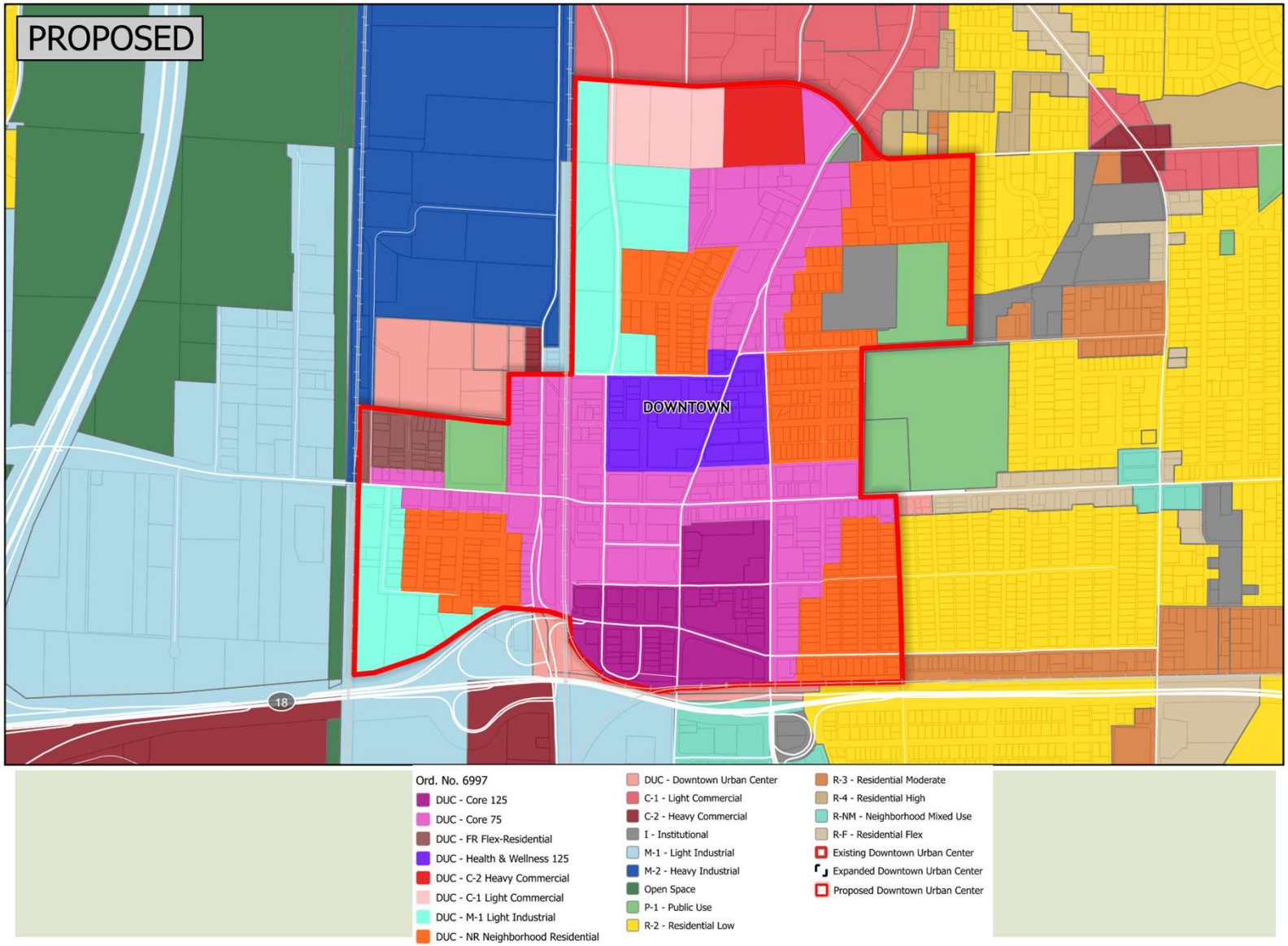
Ord. No. 6997

- Commercial
- Downtown Urban Center
- Neighborhood Residential Two
- Neighborhood Residential Three
- Open Space
- Public/Quasi-Public
- Mixed-Use
- Industrial
- Existing Downtown Urban Center
- Expanded Downtown Urban Center
- Proposed Downtown Urban Center

PROPOSED LAND USE DESIGNATION



EXISTING ZONING DISTRICTS



PROPOSED ZONING DISTRICTS

DUC – Core

The Downtown Urban Center zoning district encourages higher density residential compared to other areas of the city and mixed-use buildings. Other commercial uses are allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. (see Pedestrian Streets) per the City's currently adopted Downtown Design Guidelines.

Building Form

Expected Building Types	Development Standards
▪ Mid-rise apartments ▪ Office buildings ▪ Parking structures	▪ Maximum height 75-125 feet depending on area ▪ FAR based on location, use mix, and bonuses ▪ No maximum density

Land Use

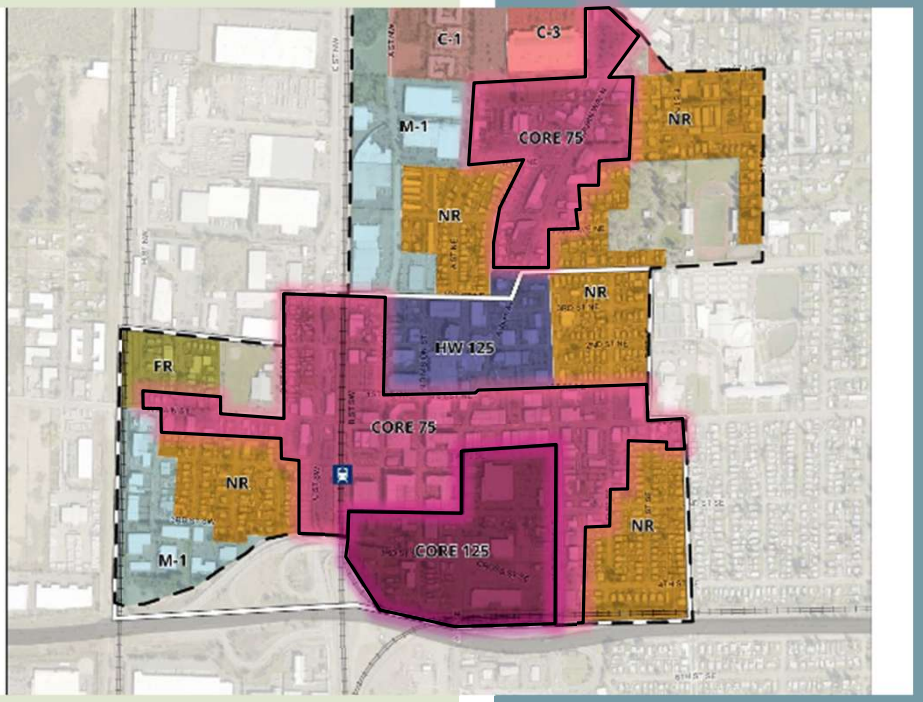
Allowed Uses	Prohibited
▪ Retail/residential vertical mixed-use ▪ Office commercial ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Restaurants/bars ▪ Craft industry/light industrial ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage and sales ▪ Most industrial uses ▪ Self-storage ▪ On Pedestrian I Streets: Drive-throughs

Development Examples



L-R: Mixed-use buildings in Salem, OR; Seattle, WA; and Kirkland, WA

DUC CORE DISTRICT



DUC – Health and Wellness

The Downtown Urban Center – Medical zoning district encourages growth of medical and medical office uses in downtown. High-density residential, mixed-use development and other commercial uses are also allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. This zone is designed to build upon and replace the Residential Office Hospital zone (RO-H).

Development Examples



L-R: Office building in Seattle, WA; office/retail mixed-use buildings in Boise, ID, and residential/medical mixed-use building in Seattle, WA.

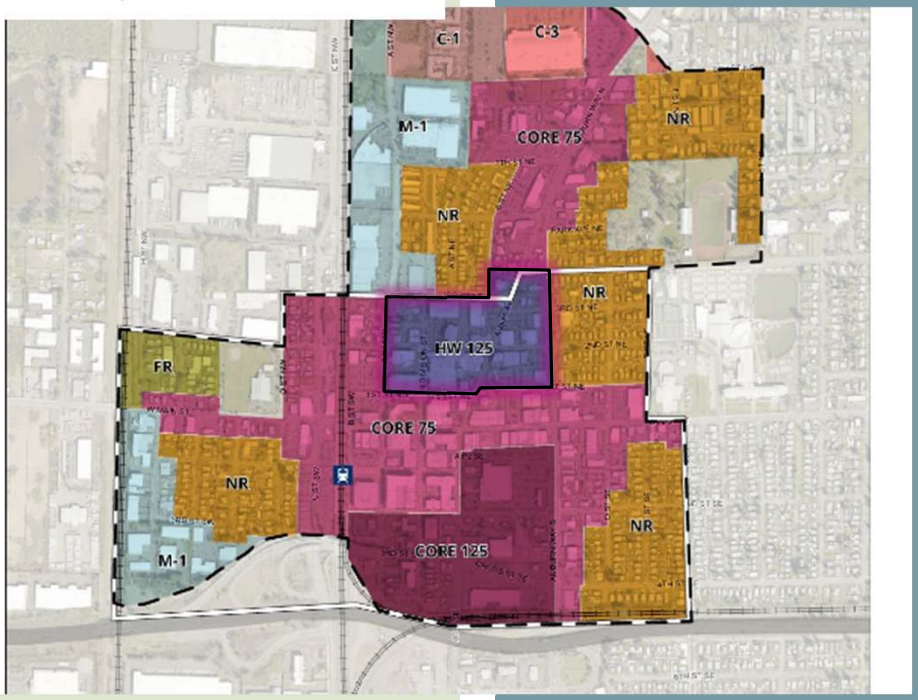
DUC HEALTH & WELLNESS

Building Form

Expected Building Types	Development Standards
▪ Medical/office buildings ▪ Mid-rise apartments ▪ Parking structures	▪ Maximum height 125 feet ▪ Reduced height allowances for non-medical uses ▪ FAR based on use mix and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Medical offices and services ▪ Hospital-related ▪ Office commercial ▪ Retail/residential vertical mixed-use ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Food production, i.e. brewery, coffee roastery ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage and sales ▪ On Pedestrian I streets: Drive-throughs ▪ Most industrial uses ▪ Self-storage



DUC – Neighborhood Residential

This zoning district is designed to support middle housing types like quadplexes, sixplexes, townhouses, courtyard housing, and small apartment buildings. It is intended to be applied in residential areas of downtown near the core with relatively small lot sizes that could support gradual infill development. Limited nonresidential uses are allowed like live/work medical offices or ground-floor retail.

Building Form

Expected Building Types	Development Standards
▪ Middle housing (including townhouses) ▪ Backyard infill detached houses and ADUs ▪ Live/work offices ▪ Small apartment buildings (up to 20 units) ▪ Small co-living housing	▪ Min lot size 2,000 sf ▪ Maximum height 45 ft

Land Use

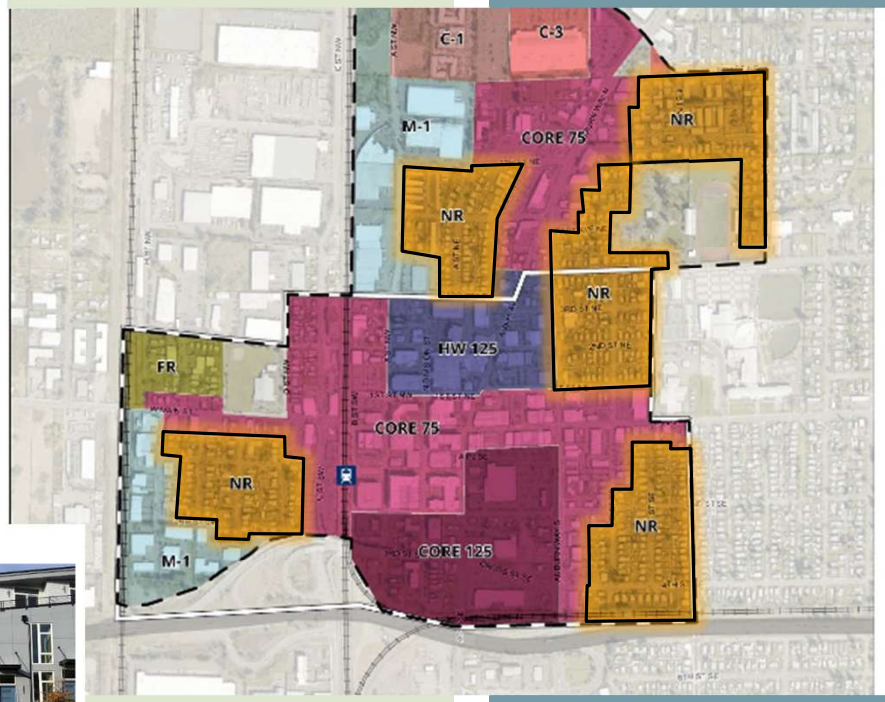
Allowed Uses	Prohibited
▪ Single-unit detached, middle housing, townhouses, small apartments, and small co-living housing ▪ Retail under 4,000 sf, including mixed use ▪ Small medical/professional offices	▪ Most commercial uses ▪ Industrial uses

Development Examples



L-R: Small apartment building in Seattle, WA; cottage cluster in Portland, WA; townhouses in Seattle, WA

DUC NEIGHBORHOOD RESIDENTIAL



Flex Residential

The Flex Residential zoning district encourages a mix of uses, including homes, artisan spaces, workshops, small light manufacturing, and commercial.

Building Form

Expected Building Types	Development Standards
▪ Workshops and single-story flexible buildings ▪ Middle housing ▪ Small mixed use buildings ▪ Small co-living housing ▪ Small footprint retail/services ▪ Houses with stores or shops in front	▪ Min lot size 3,000 sf ▪ Maximum height 45 ft ▪ No front setback

Land Use

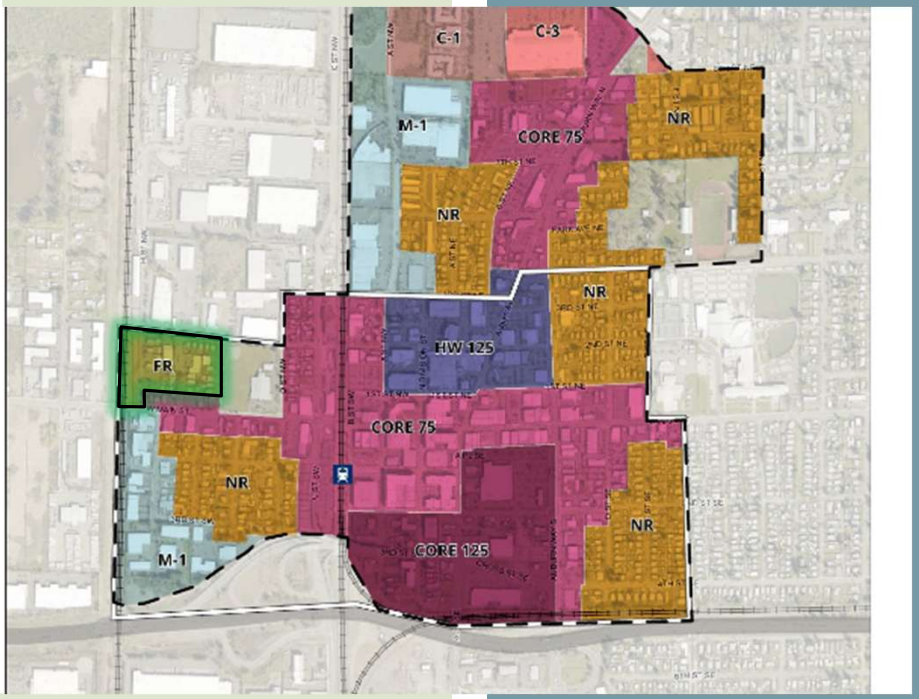
Allowed Uses	Prohibited
▪ Commercial/light industrial ▪ Residential ▪ Artisan/small workshops/ manufacturing/flex-tech ▪ Vertical and horizontal mixed use ▪ Outdoor storage/sales with screening	▪ Heavy industrial uses

Development Examples



L-R: Small retail office building in Seattle, WA; converted workshop in Bozeman, MT; live/work building in Bozeman, MT.

DUC FLEX RESIDENTIAL



NEXT STEPS



RECEIVE DEPARTMENT OF COMMERCE GRANT
- Update 2024 Auburn Downtown Plan
- Create a Planned Action Ordinance

REQUIRE EIS FOR NON-PROJECT PROPOSAL
Proposal likely to have a significant adverse impact on the environment

APPROVAL BY AUBURN CITY COUNCIL
Final EIS with preferred alternatives

ADOPTION BY AUBURN CITY COUNCIL
2024 Auburn Downtown Plan

CITY OF AUBURN DEVELOPS
Planned Action Ordinance

IMPLEMENT BY AUBURN CITY COUNCIL
Planned Action Ordinance

FIGURE 1-1 Downtown Subarea Plan Process

STAFF RECOMMENDATION

Planning Commission to recommend approval of the 2024 Auburn Downtown Subarea Plan, Appendix A Subarea Plan & Planned Action EIS, Appendix B Baseline Report Final, and associated subarea land use map and subarea zoning map amendments.

EXHIBIT 2

2024 Auburn Downtown Subarea Plan Update

October 2025



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Acknowledgements

Land Acknowledgement

The City of Auburn acknowledges the area covered by the Downtown Plan on the ancestral and contemporary lands of the Muckleshoot Indian Tribe. They have stewarded the land since time immemorial. The City of Auburn recognizes the generational harm done to the Muckleshoot people on the Salish lands through colonization and commit to ensuring that our governmental partnerships recognize the continued vibrancy of their culture and honor their sovereignty.

Participants

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- Jason Krum, Director of Community Development
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Leland Consulting Group
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Brian Vanneman

Auburn Community Members

Many thanks to all members of the City of Auburn community who offered their time to provide feedback and help guide the direction of this plan.

1 | Introduction

Purpose

The 2001 Auburn Downtown Plan (2001 Auburn Downtown Plan) set a vision and strategies for a vibrant, compact, mixed-use urban downtown core. Over the past 20 years Downtown Auburn has seen significant public investments, as well as private development, that have transformed several blocks within the downtown core into a strong, pedestrian-oriented center.



Cover image from the original Auburn Downtown Plan (2001).

This 2024 Auburn Downtown Subarea Plan Update (2024 Downtown Plan) builds on the vision and framework of the 2001 ADP vision, refining it where needed to accommodate growth through compact, pedestrian- and transit-oriented development, and ensure alignment with current City policies and community needs and priorities. These refinements include:

- Expansion of Downtown north of 3rd St NE so that the city can accommodate additional growth and retain the Regional Growth Center (RGC) designation from the Puget Sound Regional Council (PSRC).
- Expand and improve multimodal connections to align with the City's current policies and plans.
- Providing more space for housing within downtown, to align with the strategies established by the City's recent Housing Action Plan (HAP) and Housing Action Plan Implementation (HAPI) projects.

The City of Auburn received Transit-Oriented Development Implementation (TODI) grant funding from the Washington State Department of Commerce for the 2022-2023 Biennium to assist with this process. The goal is to adopt a subarea plan pursuant to RCW 43.21C.420, and a Planned Action Environmental Impact Statement (EIS) pursuant to RCW 43.21C.440(1)(b)(ii). This plan's horizon year is 2044, consistent with the Periodic Comprehensive Plan update that was adopted at the end of 2024.

The 2024 Downtown Plan was developed concurrent to the 2024 Periodic Comprehensive Plan update. Some background information shown in this plan refers to the earlier Comprehensive Plan content, as this was the adopted plan at the time the 2024 Downtown Plan was developed. Staff coordinated the two processes to ensure alignment. The City plans to update zoning within downtown following the adoption of the 2024 Auburn Downtown Plan Update, and will amend the Comprehensive Plan in subsequent updates.

Process and Participation

Public engagement has included video-conference meetings with community stakeholders, an online survey, and an information booth at the Farmer's Market to gather community-wide feedback on the plan.

Table 1-1 Summary table of engagement feedback

Event	Date	Topics Covered and Key Feedback
City Council Update	March 2022	▪ Staff provided an overview of Downtown Plan Update with City Council
Planning Commission Update	June 2022	▪ Staff update on planning process, Comprehensive Plan alignment, and regional requirements for Regional Growth Centers.
Interview – Agencies and Property Owners	July 2022	▪ Many see the downtown as in a good point of transition – still work to do, but has good investments, and is well-poised for future. ▪ Would like more activity in downtown - more things to do, more options for transit, food, etc. ▪ MultiCare expansion and ST parking garages – will be important to coordinate. ▪ Safety and security challenges are important to ensure downtown stays livable ▪ MultiCare – employees have gaps in places to get food, places to sit outside, and safety security issues, particularly at off-hours and at night, and transit schedules…existing options don't align with shifts. ▪ Want more focus on multimodal access/investments and ways to make downtown more active and livable ▪ KC Metro is developing plan for new routes…might be important to circle back on that. ▪ Bike infrastructure is lacking ▪ Want to stay connected to the city's industrial and agricultural heritage and sense of place as city develops further.
Interview – Development Community and Housing Advocates	July 2022	▪ Safety and security has been a challenge and is important to consider ▪ Need for more diverse housing options and affordable housing ▪ Open to development and expansion of housing in areas within the study area. ▪ Downtown as a gathering place for larger community – community aspect.

Event	Date	What we learned
Interview – Business Community	July 2022	▪ New commercial spaces aren't affordable to existing businesses. ▪ Downtown as a gathering place is important for the vision. Needs to be more activity, and things to do. ▪ Arts is a big focus for the downtown – looking at artistic bike racks, murals on buildings, etc. ▪ Some businesses keep doors locked even during business hours – improving comfort and safety is important. ▪ More residents downtown is very helpful to businesses. ▪ Liked some of the public space uses that occurred during COVID (outdoor seating, etc.) Would like to see some of that continue, even at a small scale. Main Street is a key focus for that. ▪ Would like to see a green space downtown – for recreation, family activities, also place for people to take pets. (Dog waste is sometimes a challenge.) ▪ Lighting improvements – buildings, catenary lights, ways to make downtown feel brighter, welcoming and safer at night. ▪ Streetscape improvements – mid-block crossings and bike rack improvements. ▪ Recent heat waves have impacted business – people are less likely to come Downtown in extreme heat.

Event	Date	What we learned
Farmer's Market Engagement	August 2022	▪ More affordable housing is needed, including senior housing and dense housing near accessible transit. ▪ Greater home ownership opportunities are desired. ▪ Affordable commercial/retail spaces are needed to expand business or move to a more central location ▪ More food options in downtown would benefit workers and visitors, especially those working at MultiCare Auburn Medical Center. Fires on Main Street were a big loss. ▪ New development is pushing existing businesses out ▪ More shopping and retain destinations would make me go downtown more often. ▪ Rents for new mixed-use buildings are too high for local businesses. ▪ Concerned about property theft, illicit activities in downtown. Want it to be welcoming and safe. ▪ Downtown green space and lunch space is desired. ▪ More open space for kids to play. ▪ Increasing trees in and around downtown has a lot of benefits. ▪ Downtown needs a swimming pool. ▪ So much harder to park these days. More parking for vehicles and secure bike parking for transit users is needed. ▪ East-west multimodal connections to Sounder are very limited. ▪ Would like a more walkable downtown. ▪ Improved bike lanes for downtown core are needed. ▪ Public transit is very important. ▪ Arts and green space are important. ▪ Main Street is important as a cultural destination. Theatre and Farmers Market are attractions. ▪ More gathering/celebration space for diverse community is needed. ▪ Would like a growing downtown that retains hometown vibe.



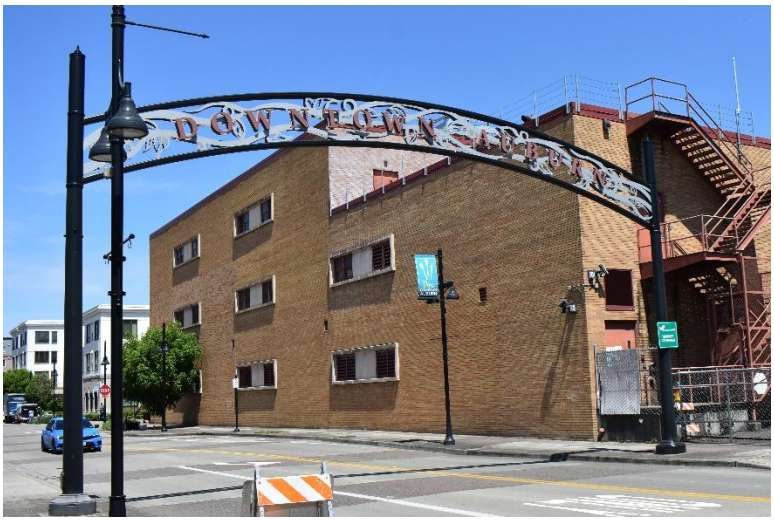


L: Farmer market engagement, August, 2022

Event	Date	What we learned
Planning Commission Presentation	December 2022	▪ Consultant team provided an update on findings from early analysis and shared early drafts for DEIS Alternatives
City Council Update	November 2023	▪ City Council coordination on alignment between Downtown Plan and Comprehensive Plan land use and housing assumptions
Planning Commission and City Council	March to November 2023	▪ Coordination with Planning Commission and City Council on incorporating draft Plan recommendations into Comprehensive Plan
Online Survey 9 responses	Summer 2021-2023	Where do you go Downtown and why? ▪ MultiCare, Merrill Gardens, Shopping, Main Street for Shopping, Haircuts, Eat and Drink on Main Street, Visit shops and eateries in the area – would love more variety, Work, Doctor Appointments, Driver's Education, Commuting, Grocery Shopping In 3-5 words, describe what you like best about Downtown Auburn ▪ Old buildings, Walkable streets (mentioned 3 times), Good bones, Shop variety, potential, Businesses In 3-5 words, describe what you like best about Auburn overall ▪ Location, Rolls with the punches, Potential, Flat, Quaint, the People, Freeway and Highway access "I wish Downtown Auburn…" ▪ Would have more disc golf and pickle ball, had more businesses, was safer for others, had less empty spaces below the apartments, had more life to it, had less abandoned businesses between Auburn Way and Downtown, Was more people oriented "I wish Auburn…" ▪ Would update the look of old buildings, Had a downtown like Sumner's, Would be a little more transparent, Would remove homeless, Was more booming and had things do to, Less drug use, Was more people oriented

2 | Existing Conditions

This section introduces the study area and describes the key themes and findings that were identified by a review of existing conditions for the 2024 Downtown Plan and Planned Action EIS (EIS). The full Baseline Report, was first developed in 2023 and partially updated in 2024, and is attached to this document as Appendix A. Content from the baseline report was updated during the drafting of the 2024 Downtown Plan and EIS.





Study Area

The City of Auburn Downtown Subarea is a unique and diverse area that includes a mix of land uses, neighborhoods, commercial areas, and architectural styles. Existing (2024) land use and related designations in the study area include:

- Downtown Subarea is an adopted area in the comprehensive plan that aligns with the Regional Growth Center. This area includes a variety of land use and zoning types.
- Regional Growth Center (RGC) is one of the Centers designations provided by Puget Sound Regional Council (PSRC). Downtown was first designated a Regional Growth Center in 2003 and is now considered an Urban Regional Growth Center, following the PSRC's Regional Centers Framework Update in 2018. To maintain this designation, the City must accommodate levels of residential and employment density.

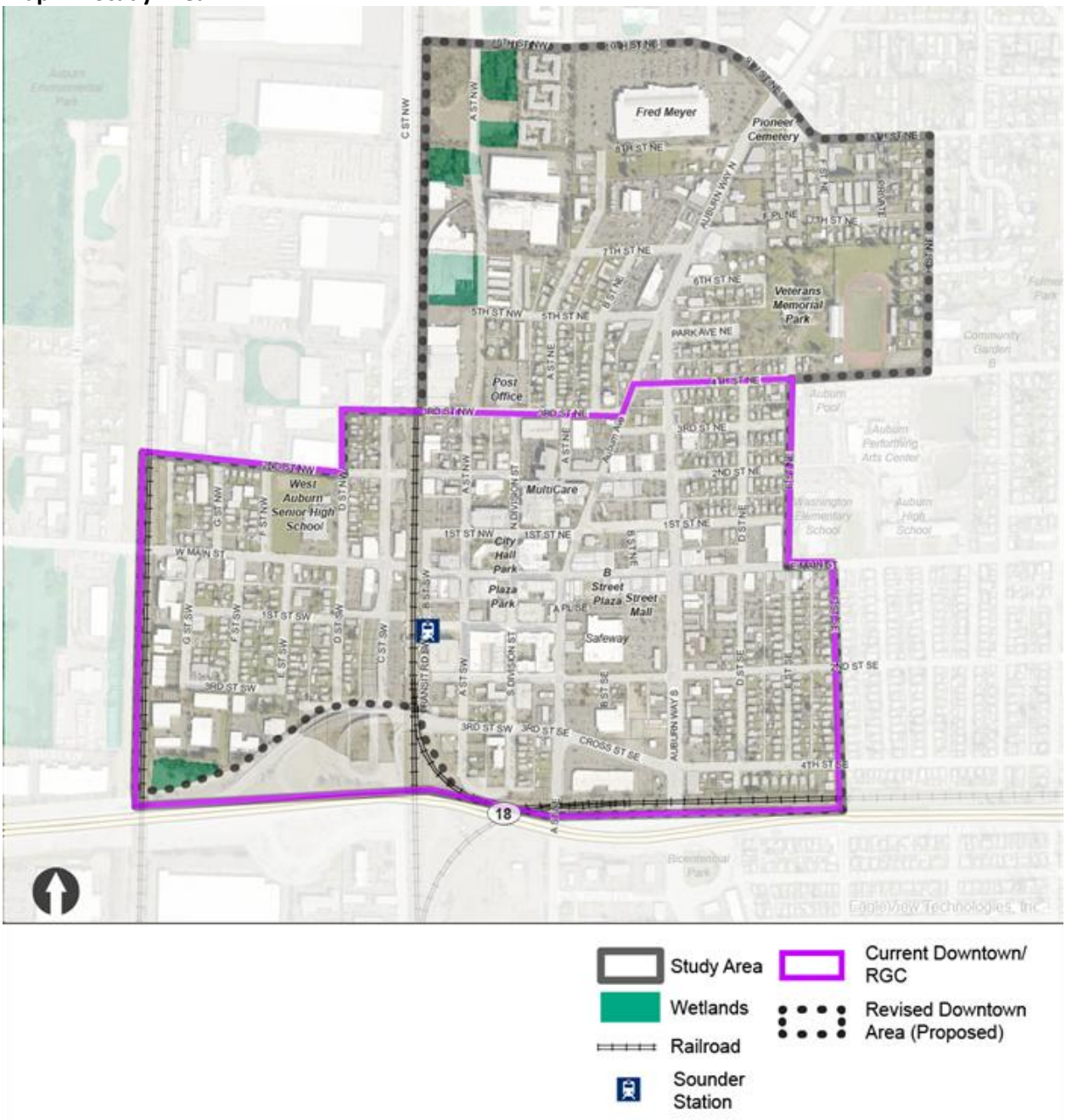
- The Downtown Urban Center (DUC) land use designation in the comprehensive plan that applies to much of the Downtown Subarea. It is implemented by a variety of zoning types including R-7, R-20, M-1 Light Industrial, and Downtown Urban Center (DUC) zone which was intended to create a strong identity of downtown Auburn.

The 2024 Downtown Plan studied an area larger than the current boundary of the Downtown Subarea/RGC to assess new opportunities for residential and commercial growth that align with regional transportation investments. This study area, which is 376 acres total, includes the current downtown Subarea/RGC area, but expands north to 10th St NE and 8th St NE, and east to H St NE. The Union Pacific Railroad and Interurban Trail corridor comprises the western border while the eastern border is defined by H St NE, 4th St NE, and E St NE.

The 2024 Downtown Plan proposes a Revised Downtown Area (Map 2-1,) and recommends updating the existing RGC to align with the Revised Downtown Area. PSRC oversees RGC boundary changes. Following the adoption of this plan, the City will coordinate with PSRC to determine the extent of RGC boundary updates.

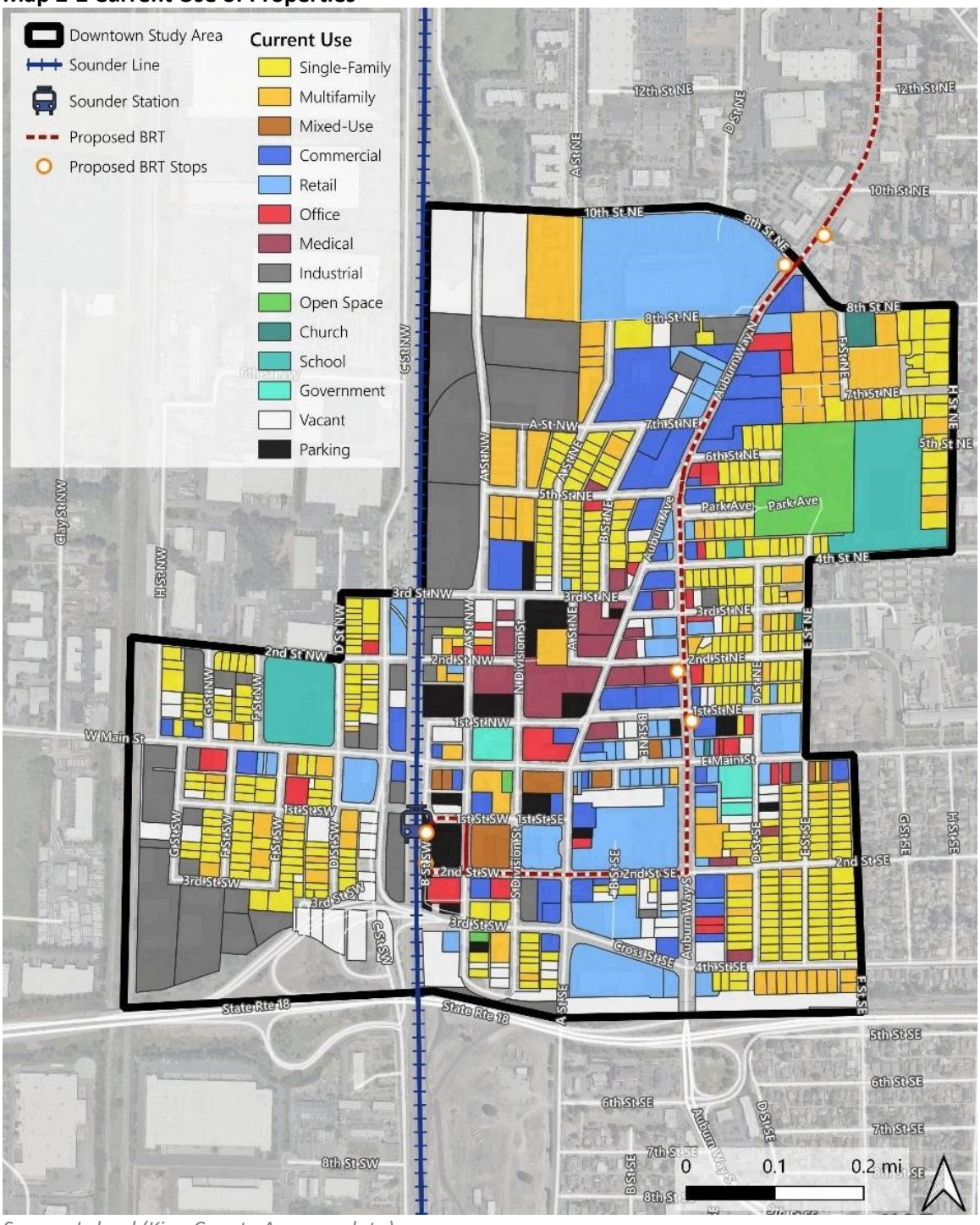
Current uses in downtown and existing zoning are shown on Map 2-2, and Map 2-3 on the following pages.

Map 2-1 Study Area



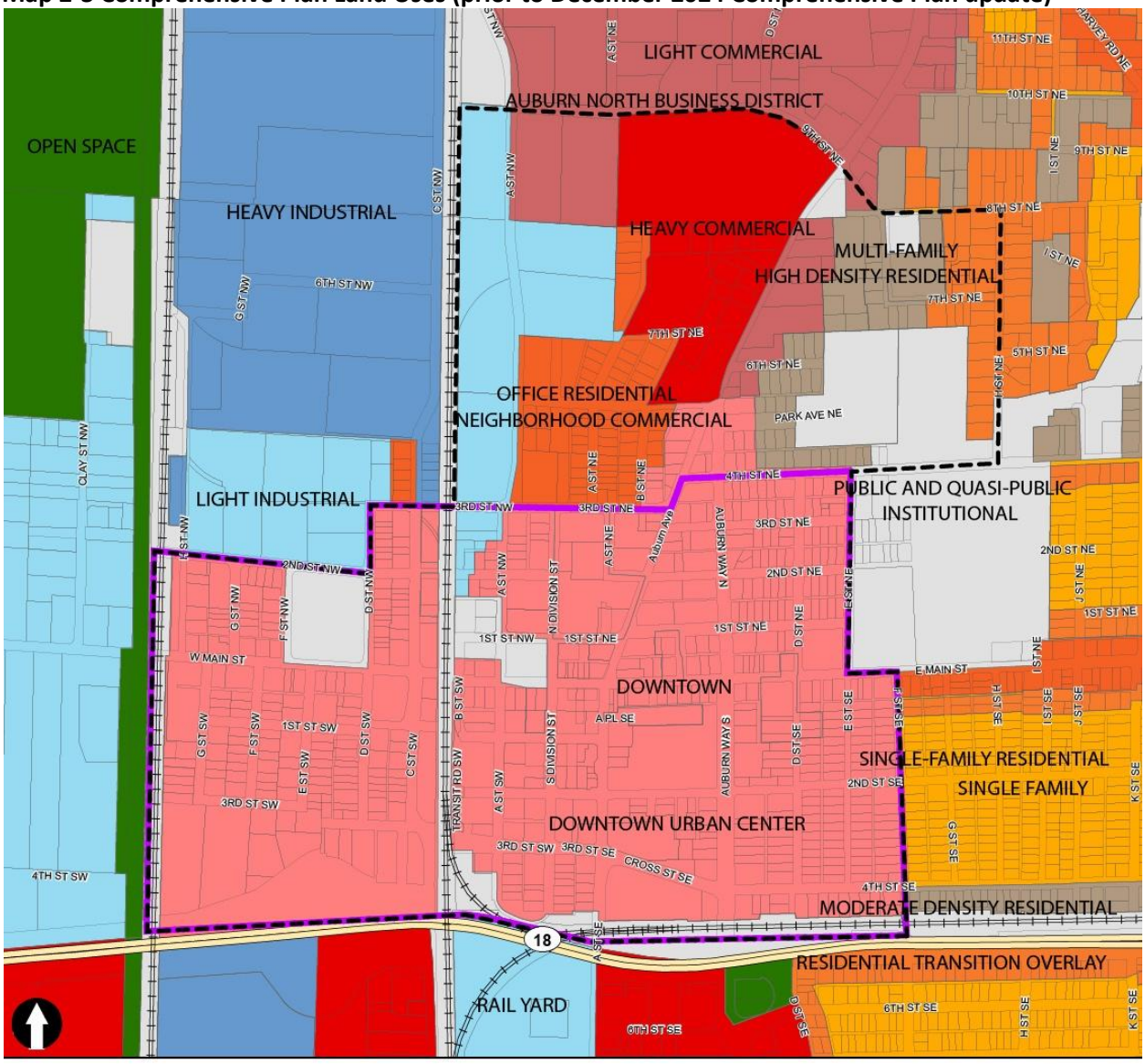
Note: Wetlands shown reflect pre-2025 inventory, and may not represent current conditions.
Source: MAKERS (City of Auburn GIS data).

Map 2-2 Current Use of Properties



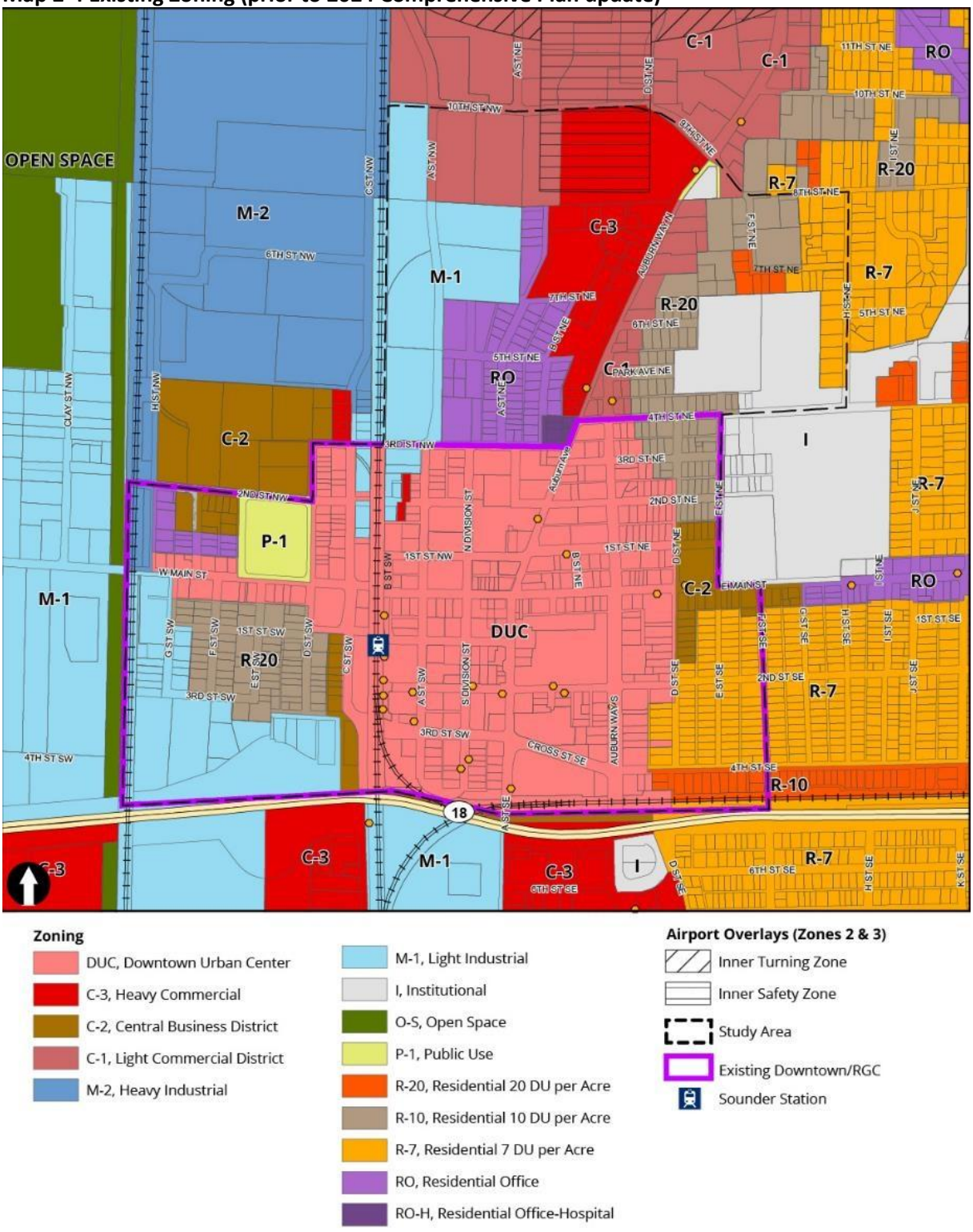
Source: Leland (King County Assessor data).

Map 2-3 Comprehensive Plan Land Uses (prior to December 2024 Comprehensive Plan update)



Source: MAKERS (City of Auburn GIS data).

Map 2-4 Existing Zoning (prior to 2024 Comprehensive Plan update)



Zoning

- DUC, Downtown Urban Center
- C-3, Heavy Commercial
- C-2, Central Business District
- C-1, Light Commercial District
- M-2, Heavy Industrial
- M-1, Light Industrial
- I, Institutional
- O-S, Open Space
- P-1, Public Use
- R-20, Residential 20 DU per Acre
- R-10, Residential 10 DU per Acre
- R-7, Residential 7 DU per Acre
- RO, Residential Office
- RO-H, Residential Office-Hospital

Airport Overlays (Zones 2 & 3)

- Inner Turning Zone
- Inner Safety Zone
- Study Area
- Existing Downtown/RGC
- Sounder Station

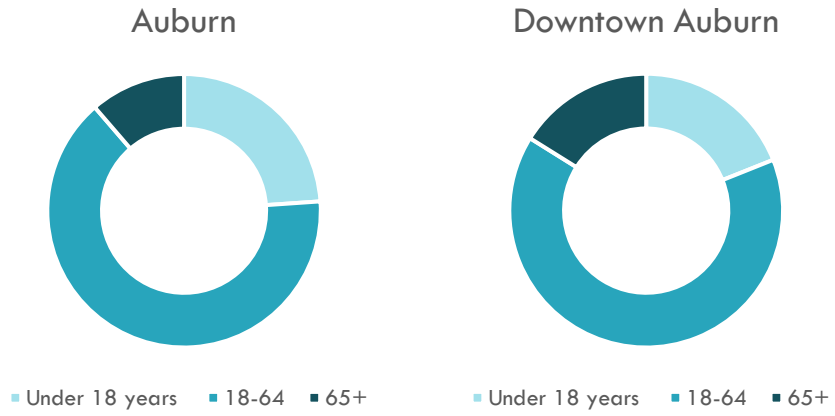
Source: MAKERS (City of Auburn GIS data).

Overall Themes

The following overarching themes emerged as key challenges and opportunities for Downtown Auburn, impacting many locations throughout the study area. Map 2-5 on page 2-9 illustrates how the plan defines character areas within the study area.

Demographics and Socioeconomics

Auburn is a historically blue-collar city and the majority of jobs and job growth in the past 20 years has been in manufacturing, though few of these jobs are in the downtown area. The downtown area accounts for around nine percent of all jobs in the city. The population of the downtown study area is moderately older than the citywide population and contains several large senior housing developments.



SOURCES: ACS 5-year estimate, 2022; ACS, Census Tract 306 and 305.1

Retail jobs make up the largest share of jobs in the study area, at 21.6 percent. The health care sector accounts for another 20.5 percent of downtown jobs, and the MultiCare Auburn Medical Center (MultiCare) is the largest employer in the study area with 635 employees.

Recent Growth and Development

Auburn's population has grown significantly since the 1980s. PSRC forecasts a population increase of about 20 percent for the next two decades in Auburn. Development in Downtown Auburn has taken place within a small part of the downtown core, and the majority of the development has been housing over some ground floor commercial space.

Market Conditions

Although information and technology jobs are growing the fastest, driven by Seattle's dominance in tech industries, health care and government are both expected to add significant numbers of jobs in the coming years regionally. Auburn's existing cluster of medical facilities makes the downtown well positioned to take advantage of this regional trend.

Increasing Activity

Recent development has started to revitalize downtown, but more work is needed to make it a mixed-use urban center. The need for more things to do downtown and a focus on making the area feel welcoming and safe was common feedback from early engagement with stakeholders and community members.

Thriving Business Center

The 2024 Downtown Plan should continue to invest in and promote downtown as a thriving business center, with a mix of commercial uses and opportunities. Commercial displacement risk may also be a challenge for some existing businesses.

Multimodal Access

Multimodal access challenges include limited separated bike infrastructure, wide arterial streets with long crosswalks, and streets with five-foot-wide sidewalks that may or may not have a planter strip. Upcoming RapidRide service along Auburn Way N will provide opportunities to improve transit access.

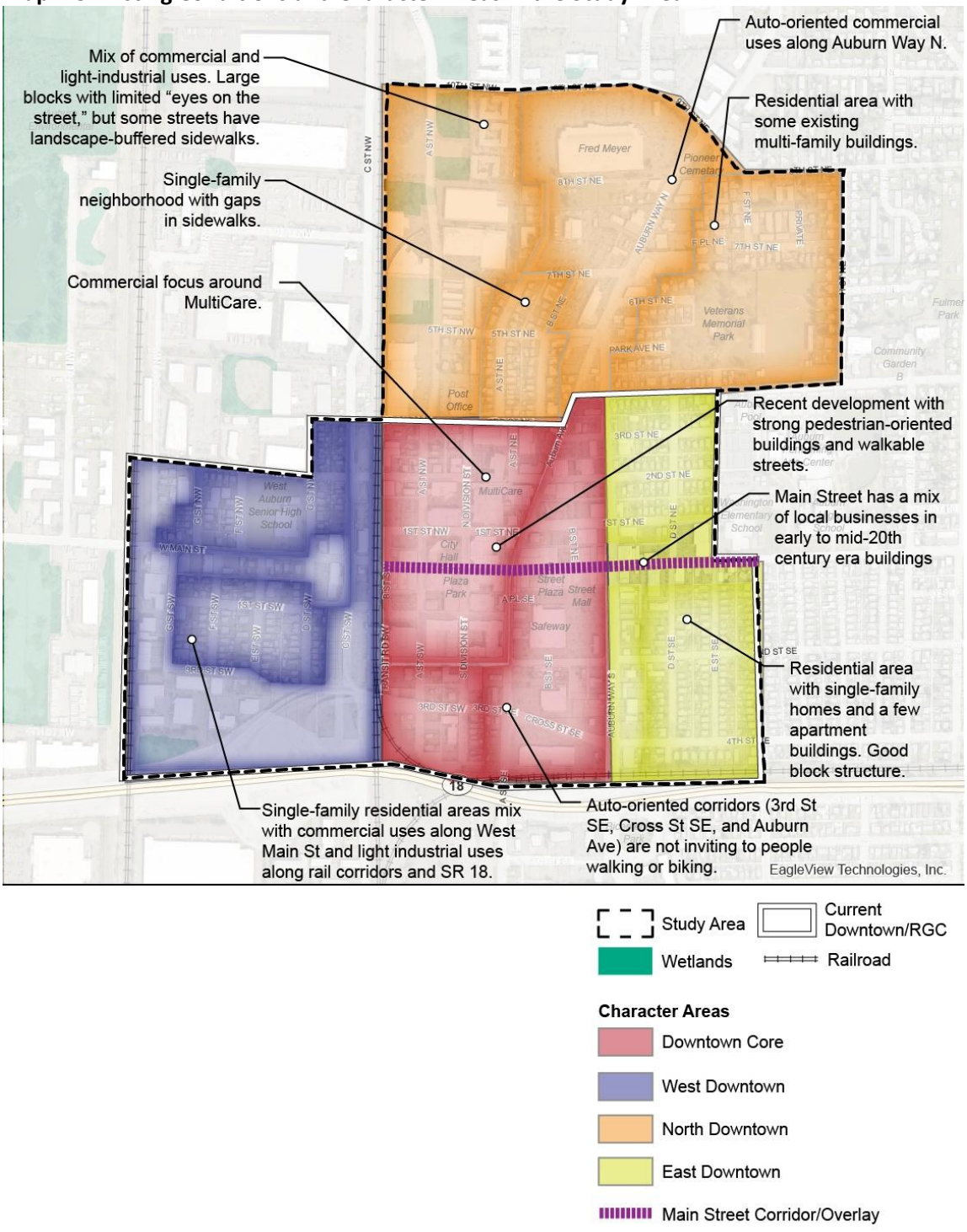
Arts and Cultural Public Investments

The City's plans for new opportunities at the Postmark Center for the Arts and the Auburn Ave Theater provide a new cultural and community gathering space within downtown and help revitalize Main Street.

Housing and Affordability

Housing affordability is a key challenge for communities throughout Washington State. The 2024 Downtown Plan should create opportunities for new and diverse housing types throughout downtown. PSRC has also indicated elevated risks of displacement within the study area and a diverse overall community.

Map 2-5 Existing Conditions and Character Areas in the Study Area



SOURCES: MAKERS (City of Auburn GIS data).

Assets and Opportunity Areas







- Main Street is unique within Auburn and an asset to the overall downtown area. Programs to help property owners improve facades and make building improvements could continue revitalization efforts. The area also has many existing small businesses, and some have struggled to find affordable retail space in newer buildings.
- MultiCare is a major employer and anchor within Downtown Auburn. Future expansion plans may continue to develop around this hub.
- The West Downtown area has been considered part of Downtown in past planning cycles, but there are both access and market challenges for significant future development.
- Expanding to North Downtown could allow for Transit-Oriented Development (TOD) opportunities around upcoming Rapid Ride line. There are some large parcels and development opportunities in that area.

Growth Capacity

Downtown Auburn should provide adequate growth capacity to retain the Regional Growth Center (RGC) designation. Expanding the existing RGC boundary may allow the city to provide more opportunities for population and job growth while also aligning with plans for new frequent bus service.

Elements

The review of existing conditions also identified the following information relevant to the elements and key topics included in this plan.

Land Use

- There are pockets of auto-oriented commercial uses throughout the study area that provide opportunities for higher-density development.
- Other City-owned properties, such as surface parking lots, could offer additional sites for new development, or could continue to serve as surface parking.
- There are several large and mid-size commercial properties in downtown that could redevelop within the timeframe of this plan.
- About a quarter of downtown housing units in the study area are single-family homes, and a third of housing units are in large developments of 50 units or more.
- The downtown study area population is classified by PSRC as having a higher risk of displacement due to redevelopment.



Some typical patterns of land use in downtown Auburn.

Urban Form and Open space

- There is limited open space and tree canopy cover in the study area, connections to assets like Veteran's Memorial Park require people walking and biking to cross busy arterials. Downtown would benefit from more green open space and access to shade to reduce urban heat.
- Redevelopment within the Downtown Subarea areas has delivered a strong pedestrian built-environment within the downtown core.

- The pedestrian experience of downtown is mixed. Newly updated streets meet standards and support good pedestrian circulation. Some older streets do not meet current standards for sidewalk width and some arterial streets have minimum five-foot-wide sidewalks without planter strips.
- A safety analysis found that some Principal Arterial and Arterial streets, which carry higher numbers of vehicles, have higher numbers of collisions.
- Increasing activation through groundfloor commercial uses, events, creative streetscape uses/programs, and/or linking of public space and streetscape improvements is an important opportunity. Groundfloor spaces in newer developments have been slower to fill.
- There are two public high schools and one public elementary school located in or adjacent to the study area.
- The highly developed context of downtown Auburn limits natural environment processes within the study area. Redevelopment could offer opportunities for green stormwater infrastructure, urban trees canopy cover, parks and green open spaces, and other elements of green infrastructure.
- Downtown Auburn does not appear to be at elevated risk from riverine flooding, though stormwater flooding may present some challenges.
- There are wetlands in the northwest portion of the study area. Wetlands shown in this plan reflect the pre-2025 inventory, and some are impacted by development. Redevelopment of other areas of North Downtown could provide an opportunity to enhance overall ecological conditions.
- Urban heat is a challenge for the Downtown area. Lack of shade leads to higher temperatures, which can be very challenging for vulnerable populations (seniors, low-income, etc.)
- Air pollution sources from arterial and rail corridors should be considered when locating new housing.



L: landscaped plaza at Auburn Station. R: roses at a legacy house near SR 18.

Transportation

- The transportation analysis found that traffic impacts from land use changes proposed in the 2024 Downtown Plan could be mitigated by making improvements in key locations. The City will monitor change and consider future improvements as redevelopment occurs. See EIS for more details.
- There are several projects in and around the Downtown Subarea, such as the Sound Transit construction of a new parking garage to accommodate parking demand for Sounder rail line riders.
- The Downtown Subarea has adequate sidewalk presence, but sidewalks are varying in age and conditions. There are limited class II and class I bikeways[1] in the city, but the downtown area is in proximity to regional trails. There are also principal and minor arterials and freight rail lines running through the study area boundary.
- The City does not administer transit service. Sound Transit, King County Metro Transit, Pierce Transit, and Muckleshoot Tribal (MIT) Transit provide bus service. The city also has Sounder rail service, operating on the north/south BNSF rail line, provided by Sound Transit.
- Finally, parking is offered through on-street public parking, off-street public parking, and off-street private parking.



L: cyclist riding on the sidewalk past City Hall plaza. R: Metro DART bus at Auburn Station.

[1] This refers to the definitions for Biking LOS standards that the city is using for the 2024 Comprehensive Plan update. Class II bikeways are generally bicycle lanes in the roadway but separated from vehicular traffic. Class I bikeways are bicycle facilities that are outside the roadway and are usually separated from roadway traffic by curbing, landscaping, buffer hardscaping, or physical barriers.

Utilities and Stormwater

- The Water System Plan developed for the 2024 Comprehensive Plan Update considered land use changes consistent with the 2024 Downtown Plan. Though the downtown area generally has adequate water service and can meet future demands, water system improvements were identified in the Water System Plan to address specific deficiencies over the planning period. The City will continue to monitor service needs in downtown as development occurs.
- Sewer lines run in alleyways throughout much of the downtown area, which can limit the type and size of development that can occur without moving these facilities.
- The City has regulations that must be adhered to in terms of utilities and stormwater. The City's Storm Drainage Utility coordinates the City's municipal NPDES permit compliance efforts and leads efforts to manage flooding in the city. To effectively plan for future activities and improvements for the storm drainage system, the City has undertaken comprehensive planning efforts specific to stormwater management that go beyond regulatory compliance.
- The City identifies the northeastern part of the Downtown study area – generally east of Auburn Ave. and north of Main St. – as within the City's Groundwater Protection Zone 1, where infiltration of stormwater runoff from pollutant generating surfaces is not allowed without enhanced treatment and approval from the City Engineer, per the City's SWMM.
- Proposed development and growth should take into consideration potential adverse impacts to stormwater from potential increases in impervious surface.
- Public utilities should be upgraded and increased as necessary to accommodate growth and development.
- Attention to proper monitoring of water quality is crucial to public health and safety.



Assets, Challenges, & Opportunities

This chapter describes existing assets and the challenges this plan addresses. Also see Appendix A: Baseline Report for additional detail. The following lists are not meant to be exhaustive but represent the range of downtown Auburn's unique features.

Assets











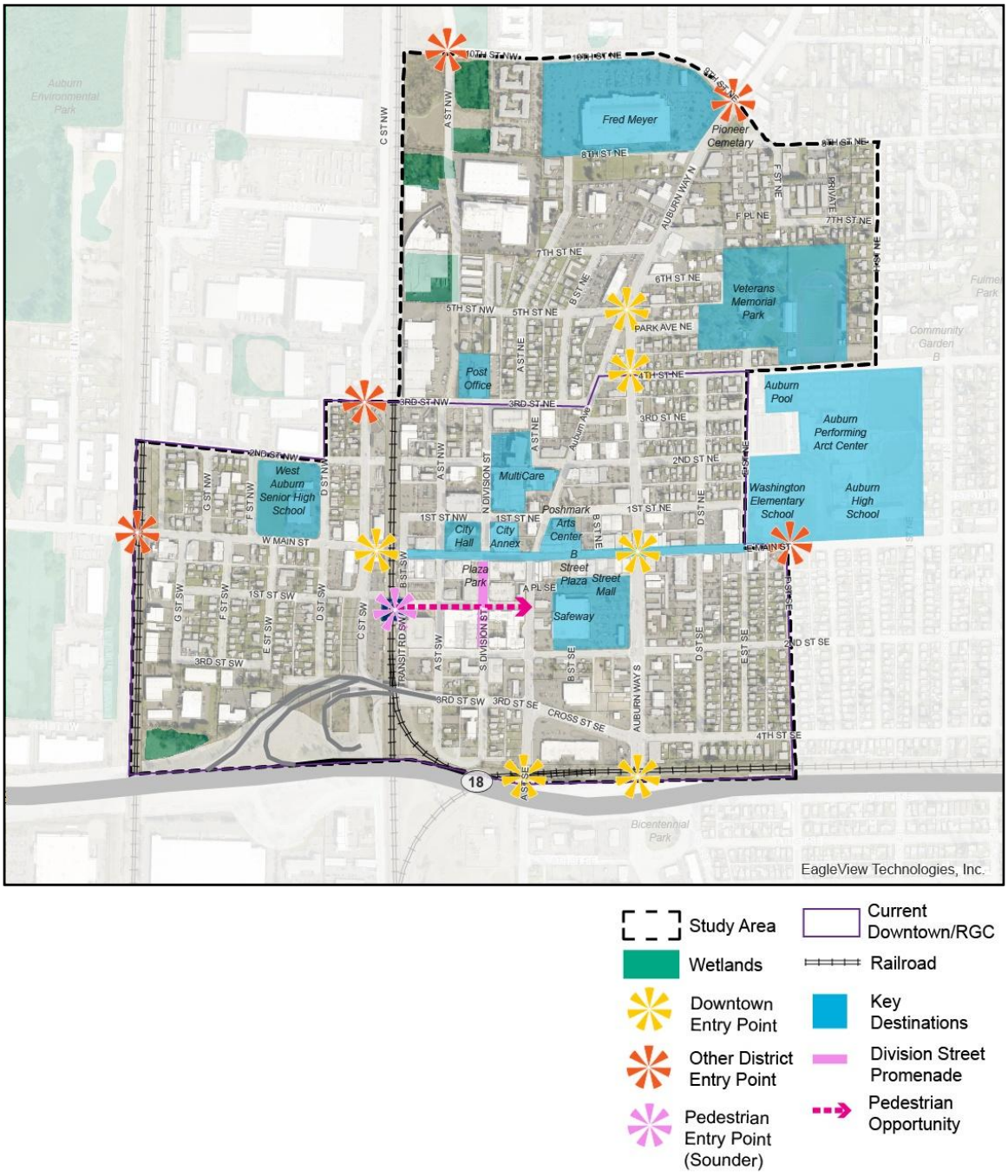
Key Destinations and Neighborhoods

- Compact, pedestrian-oriented Downtown Core
- Downtown public plazas
- Main Street
- Division Street "Promenade" from 3rd Street SE/SW to Main Street
- MultiCare employment hub and medical services
- Multiple grocery stores: Safeway, Fred Meyer, smaller groceries
- City Hall & Annex
- Local businesses (East Main and other locations)
- Veterans Memorial Park
- Proximity to local services and amenities
    - Multiple Schools: West Auburn High School, Auburn High School, Washington Elementary School
    - Auburn Performing Arts Center (APAC)
    - Postmark Center for the Arts
    - Les Gove Park and Farmer's Market
    - Auburn Pool
    - Auburn Theater (design work underway as of early 2025)

Transit Access

- Auburn Transit Station
- Sounder commuter rail service
- Metro, Pierce Transit, Sound Transit, and MIT Transit Bus service
- Rapid Ride I Line – upcoming

Map 2-6 Assets – Key Destinations and Gateways



Source: MAKERS

Challenges

Circulation Challenges and Barriers

- Multiple arterial streets
- Railroad corridors divide downtown
- Sidewalk gaps and older sidewalks that do not meet current standards (Auburn Engineering Design Standards for Downtown Sidewalks, 10.09.01)



Housing and Economic Development

- Commercial space affordability
- Ensuring downtown is safe and welcoming
- Increase affordable housing
- Additional lighting on buildings and aesthetic light treatments to enhance downtown



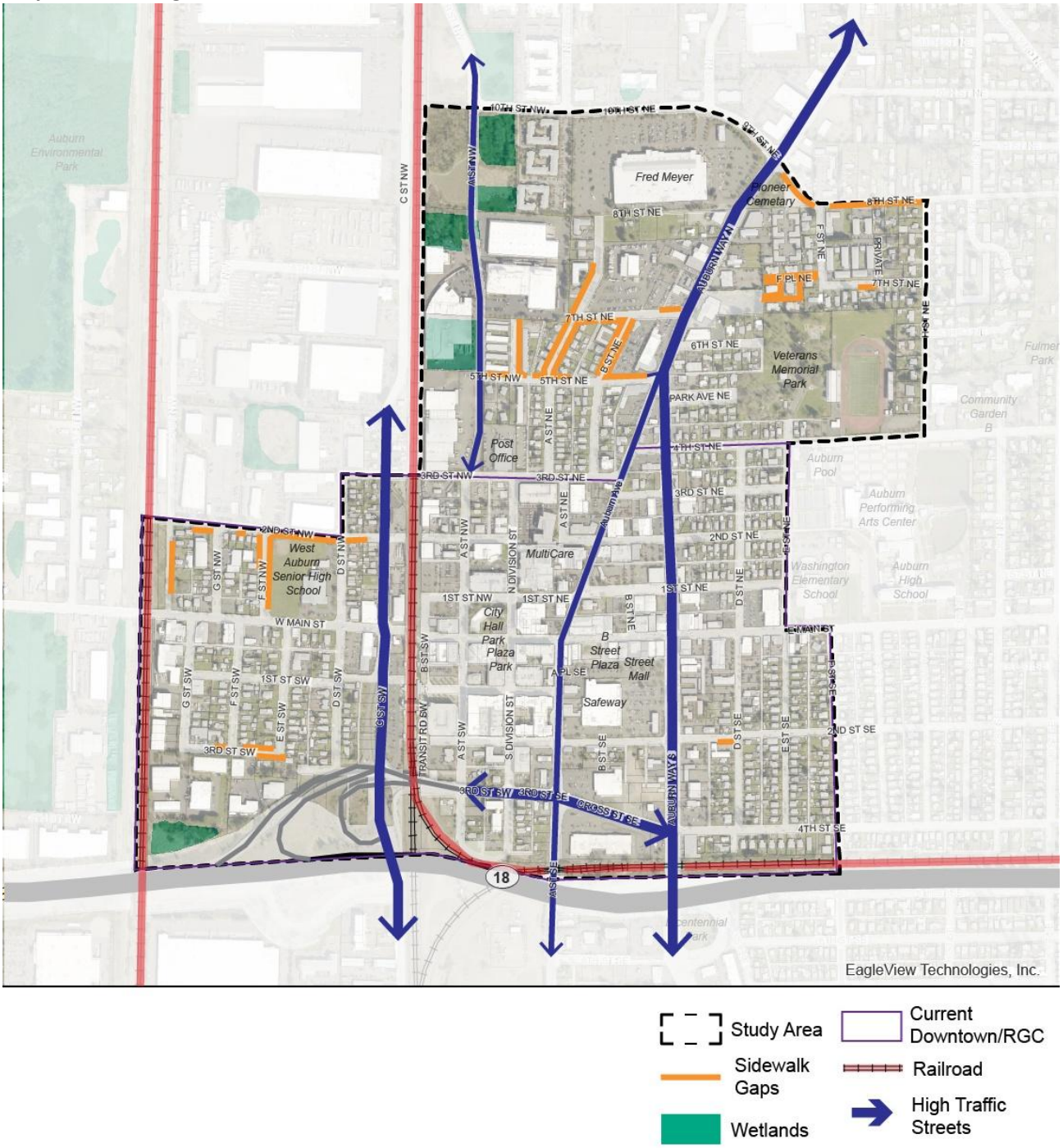


Public Space

- Lack of parks downtown
- Low activation of existing public spaces



Map 2-7 Challenges – Arterials and Circulation Barriers



Source: MAKERS

Opportunities

Arts, Culture, and Community



- Arts and entertainment node and/or creative district around the former Auburn Avenue Theater site
- Encourage new restaurants and things to do throughout Downtown, especially in the Downtown Core
- Potential for more "craft" industrial uses in West Downtown
- Make greater use of pedestrian-oriented and festival street layouts



- Dedicated food truck locations that can serve downtown workers, commuters, and visitors
- New park space
- Highlight gateways into Downtown

Housing and Development



- Potential for more mixed-use development opportunities in North Downtown adjacent to RapidRide.
- Encourage missing middle housing types and small apartments in residential zones in horizontal and vertical building configurations.
- Provide flexibility in ground floor commercial space to temporarily accommodate housing while spaces are being filled.

Transportation

The plan is exploring the transportation improvements identified in the list below.



- 2024-2029 Transportation Improvement Program Projects (see Planned Transportation Projects for Downtown Auburn on page 6-6)
- Other transportation improvements the 2024 Downtown Plan recommends include:
    - Pedestrian and streetscape improvements on Main St Corridor (i.e. streetscape and/or traffic improvements.)
    - Implementing planned bike routes
    - Improving ped/bike crossings in key locations
    - Improving E-W bike circulation
    - Addressing sidewalk gaps in key areas



Economic Development

- Opportunity to increase employment options in the Downtown Subarea
- Amend MFTE benefits to require activation of ground floor or other commercial space as part of mixed-use development
- Create spaces for small business and new startups in downtown
- Encourage neighborhood scale commercial development in residential areas





3 | Concept

Goals and Objectives

The following goals and objectives guide the content and recommendations of this 2024 Auburn Downtown Plan Update.

Land Use and Economic Development

Goals

1. Create new and diverse housing and employment options throughout Downtown Auburn.
2. Promote a thriving business community.
3. Provide sufficient future growth capacity to retain Auburn's Regional Growth Center designation.
4. Activate downtown through increased housing and employment options, recreational activities, and open space.

Land Use and Economic Development Objectives

a. Expand Downtown boundary north of 3rd St NE and create a new mixed-use hub along Auburn Ave to provide more growth and redevelopment opportunities.

b. Create an Arts and Culture hub at Auburn Ave and E Main St to provide a new cultural and community gathering space within downtown and help catalyze redevelopment.

c. Encourage a hub of medical and wellness to better define the area around MultiCare Auburn Medical Center.

d. Promote affordable commercial spaces.

e. Encourage new restaurants and shops to open or relocate to Downtown.

f. Retain the human-scale character of the Main St corridor, while supporting infill redevelopment. Implement/expend building façade improvement program to encourage updates to existing buildings.

g. Promote and/or invest in public realm improvements (park and open space, streetscape activation and enhancement, lighting, etc.) to make

Downtown feel safe and welcoming at night and is an attractive place to visit and/or live.

Housing Objectives

a. Encourage market rate development Downtown through zoning changes and flexibility in housing choices.

b. Encourage new affordable and supportive housing Downtown through zoning changes, expansion and re-tooling of MFTE program.

c. Encourage preservation of existing naturally affordable housing.

d. Promote home-ownership opportunities through strategies such as unit-lot subdivision for middle housing.

e. Encourage missing middle housing and small apartment opportunities in residential areas.

Transportation

Goals

1. Complete or address bicycle and sidewalk gaps in Downtown and enhance connectivity to transit services.
2. Improve pedestrian and bike mobility and safety.
3. Reduce vehicle congestion and improve circulation.

Objectives

a. Improve circulation for pedestrians and bicyclists, particularly in North Downtown and between the downtown core and West Downtown and to transit facilities.

b. Work with Transit Agencies to get improvement to their transit stops. (Lighting, adequate space, buffers from traffic, etc.)

c. Create new bike facilities and bike parking

d. Improve sidewalks along key arterials to enhance accessibility and comfort.

e. Provide electric vehicle charging options within parking lots and parking garages and support shift to electric vehicles

f. Complete Street roadway improvements that reduce congestion and/or improve circulation.

Urban Design and Community Livability

Goals

1. Promote comfort and safety to ensure Downtown is welcoming to all.
2. Ensure Downtown remains a livable community as redevelopment continues and expands.
3. Create new opportunities for gathering and community-wide celebrations.
4. Encourage growth but maintain Auburn's hometown feel and sense of place.

Objectives

a. Establish Downtown as an arts and cultural center for the greater Auburn community.

b. Activate downtown through events, creative uses of public spaces and streets, etc.

c. Encourage new shops and restaurants to provide more things to do, places to eat, etc.

d. Encourage more activity along Main Street and other streets within Downtown by promoting creative uses, such as events, outdoor dining, day and night activities, pedestrian-focused street environment, etc.

e. Celebrate cultural diversity and provide opportunities for gathering and celebration.

f. Create a new park and green space within Downtown that supports needs of all ages (i.e., comfortable for seniors, play spaces for kids and grandkids, picnics, light recreation, etc.)

g. Promote sustainable design and climate resilience by supporting transition to electric vehicles and promoting charging infrastructure; improving non-motorized access to encourage more people to walk or roll; encouraging energy-efficient buildings; and reducing the urban heat island effect within downtown.

h. Assess existing light levels to determine where improvements may address perceptions of safety and enhance an attractive street environment at night.

i. Connect to and celebrate Auburn's history and build on the unique character of Downtown

Urban Design Framework

The following list items provide an outline description of the central ideas of the Auburn Downtown Subarea Plan.

Core Downtown

- Serves as the heart of the Downtown Subarea and focus for new activities.
    - Proposed zone changes, partnerships, and/or programmatic actions will promote medical and wellness uses around MultiCare and encourage economic development opportunities that support community health and wellness.
    - Public investments, parnterships, and/or programmatic actions to encourage greater activity within downtown .
    - Create and support a new arts and culture hub centered around Auburn Ave and E Main St.
    - Construct a new City-owned green space near Postmark Center for the Arts.

E Main Street

- Build on the unique assets of E Main St while also allowing for growth and redevelopment over time.
- Implement streetscape and/or traffic improvements to promote more pedestrian activity.





North Downtown

- Create new node of development along Auburn Way North
    - Allow new missing middle housing types in existing residential areas to to encourage new housing while being sensitive to displacement risks.
    - Build on public investment of KC Metro's new I line Rapid Ride transit service.
    - Enhance non-motorized connections using a mix of street facilities and through-block connections within developments.
    - Promote green infrastructure investments with redevelopment, such as street trees for shade, GSI, and other investments.



West Downtown

- Promote “craft” industrial uses that are compatible with residential areas such as small workshop spaces, breweries, etc.
- Refinements to zoning to align with what is feasible in this area in terms of growth and density.





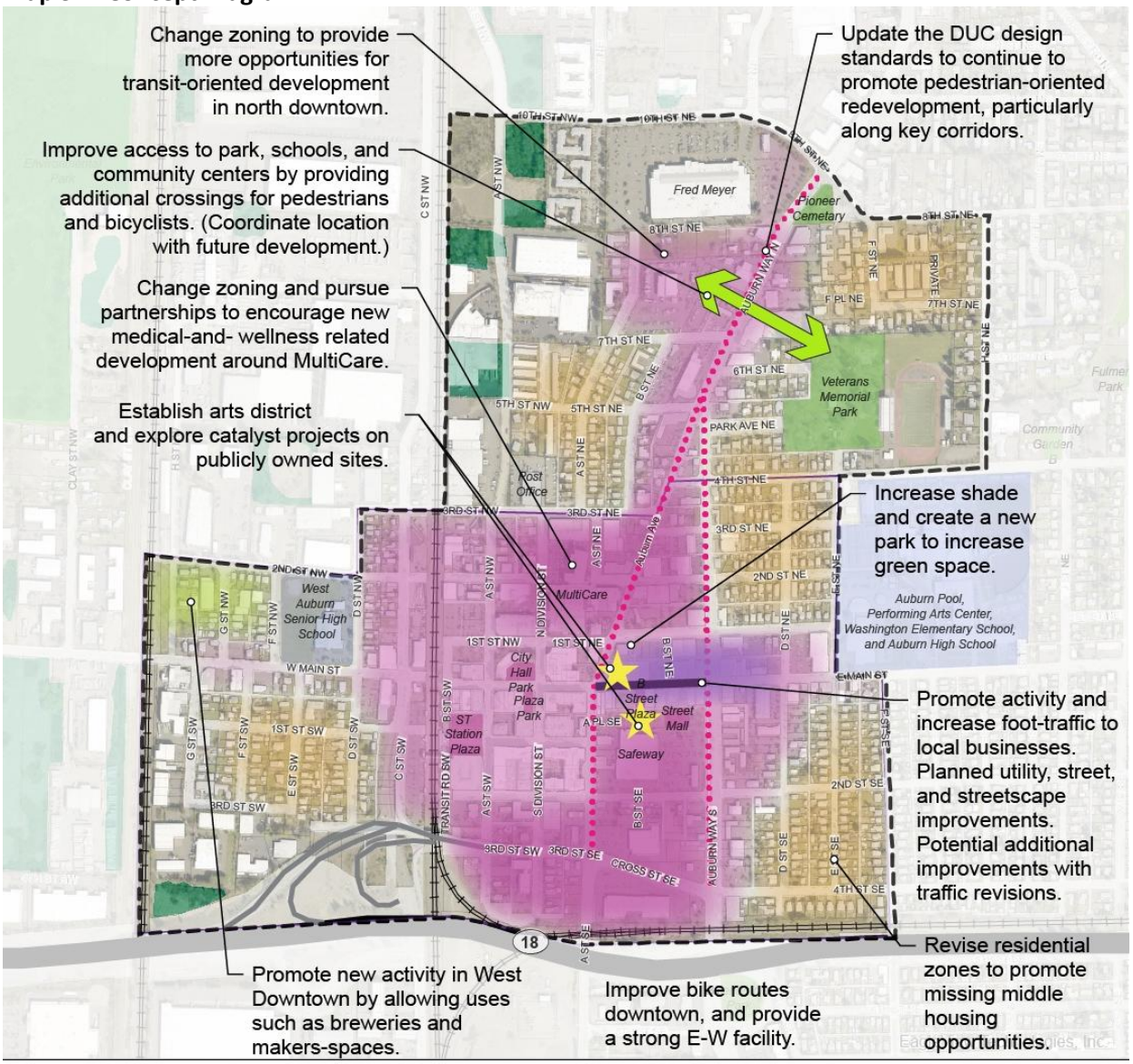
East Downtown

- Support E Main St uses and allow new missing middle housing and small apartment types in residential areas to encourage new infill housing while being sensitive to displacement risks.





Map 3-1 Concept Diagram



Source: MAKERS

4 | Land Use & Urban Design

This element describes recommended changes to zoning and other development regulations that will shape the types and intensities of land use in Downtown Auburn. These recommendations seek to align rules and guidelines with Auburn's updated vision and goals for its downtown.

This plan proposes updated zoning proposals and concepts that are targeted to build on the momentum of private investment and redevelopment that the city has seen in recent years within downtown. It studies potential refinements to existing zones within downtown to align with current market feasibility and the expansion of downtown to new areas to provide additional opportunities for population and job growth. This chapter also explores programmatic tools and other opportunities to improve development feasibility, reduce risk of commercial displacement, and promote overall economic development. Such tools include recommendations for updates to the Multifamily Housing Property Tax Exemption (MFTE), the scope of Business Improvement Areas, and reconsideration of ground floor retail and minimum parking requirements.

Specific redevelopment opportunity sites currently owned by the City are identified and evaluated with a strategic lens for the role they could play in building upon existing downtown assets. For more details on City-initiated investments, see Opportunity Sites in Chapter 5|Housing & Redevelopment.

The plan also makes recommendations for future design standards updates that will support the unique needs and opportunities within Downtown Auburn.

Under these recommendations, approximately 5,879 new homes and 3,386 new jobs are expected in Downtown Auburn by 2044 (reference Table 2-3 of Appendix A). This represents an increase of 3,346 new homes and 1,883 new jobs compared to what is anticipated with no action taken (reference Table 2-4 of Appendix A). This plan assumes a target of 17% of the 19,520 net new jobs needed by 2044 and approx. 49% of the 12,112 net new housing units by 2044.

Table 4-1 2024 Auburn Downtown Plan Anticipated Growth 2021-2044 (population, housing, and jobs)

Location	Current (2021)			Preferred Alternative (2044)		
	Jobs	Population	Housing	Jobs	Population	Housing
Existing RGC	3,554	2,253	1,033	6,364	10,601	5,202
Revised Downtown Area (Proposed)	4,799	3,708	1,724	8,185	15,478	7,603

Regional Growth Strategy

State and Regional Plans

The Growth Management Act requires comprehensive plans, including subarea plans like the 2024 Auburn Downtown Plan, and development regulations to be consistent with 13 goals, as set forth in RCW 36.70A.020, as well as the goals and policies of the Shoreline Management Act, regarding shorelines of the state, set forth in RCW 90.58.020. The goals address well-managed urban, rural, and resource lands and promote environmental quality by focusing growth in urban areas, advancing housing and employment opportunities, providing adequate public services, and more. (See EIS for more details.)

Puget Sound Vision 2050

The City of Auburn downtown subarea is identified in the Puget Sound Regional Council Vision 2050 plan as a Regional Growth Center (RGC) intended to accommodate a significant share of future growth. PSRC uses "activity units" to measure density of development and potential for growth within the RGC framework.[2] An activity unit is one person or one job. RGCs and other types of centers are eligible as "priority areas for PSRC's federal transportation funding" and support PSRC's "objective of encouraging development of compact, livable centers as an opportunity to accommodate a significant portion of the region's growth."[3] (See sidebar for RGC requirements.)

Regional Growth Center (RGC) Requirements

PSRC's requirements for Urban Growth Centers:

- Minimum **18 activity units per acre** existing density
- Minimum **45 activity units per acre** planned density
- Size between **200 and 640 acres**
- Minimum mix of **15%** residential and employment activity

Future Growth

The 2001 Downtown Plan established Downtown Auburn as a center for growth and economic development. This plan has been implemented over time through several public and private investments, including significant redevelopment of the core downtown area over the last decade. Analysis of development as of 2022 shows that there is still capacity within the existing RGC boundary to accommodate future growth to meet the 45 activity units per acre target. However, expanding the RGC boundary to align with the proposed Revised Downtown Area provides the city more space to accommodate new housing and jobs and it would align with regional expansion of frequent bus service. (See EIS for more analysis.) This plan recognizes VISION 2050's goal of attracting 65% of regional population growth and 75% of employment growth to centers and high-capacity transit station areas.

[2] Puget Sound Regional Council. "Regional Centers Framework Update." March 22, 2018. https://www.psrc.org/media/3038

[3] Puget Sound Regional Council. "Regional Centers Framework Update." 2018

Recommendations

DP-LU.1 Provide more opportunities for growth within Downtown Auburn and align with regional growth strategies by coordinating with PSRC to expand the Regional Growth Center boundary.

Zoning Concepts

This subarea plan recognizes the efforts and investments that have gone into creating the Downtown Urban Center (DUC) zone and the successful redevelopment that has occurred within the downtown core under the 2001 Auburn Downtown Plan. This plan builds on the success of the existing zoning and recommends updates where development has not met expectations and/or where more flexibility is needed for new encourage new jobs and housing within the city, including affordable housing.

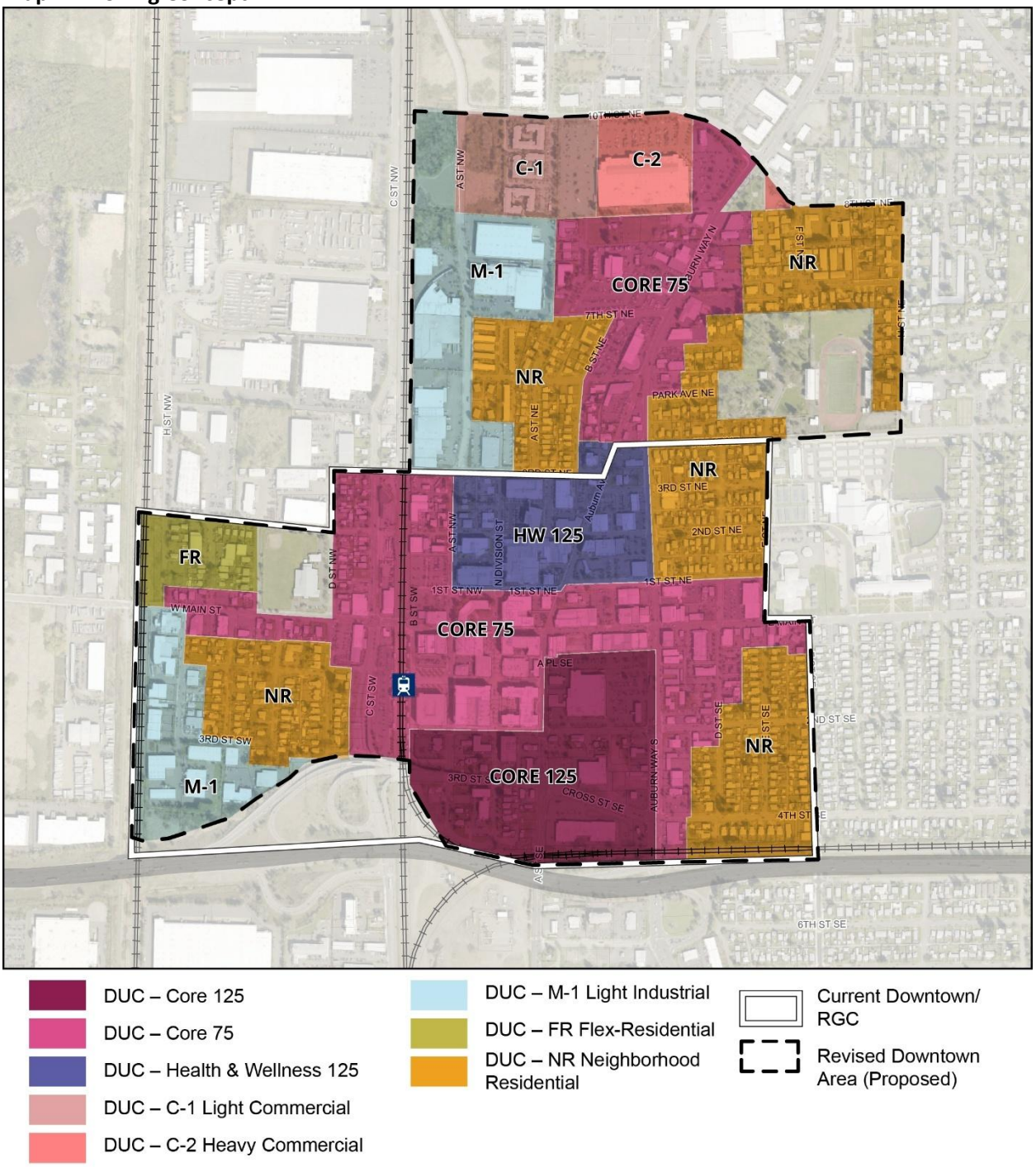
This plan proposes the following changes to zoning within downtown*:*

- Considers a new node of mixed-use development in North Downtown*.*
- Creates a new subset of districts for the DUC in which downtown design guidelines would apply.
- Expands and revises the DUC – Core district (formerly the DUC zone) to new areas. Revisions consider different heights and updates to design standards in key locations that align with market conditions and development feasibility in those areas.
- Proposes a new DUC – Health and Wellness district that allows a range of housing types and some neighborhood serving businesses.
- Proposes a new DUC – Neighborhood Residential district that allows a range of housing types, including middle housing and small apartments, and some neighborhood serving businesses.
- Proposes a new DUC – Flex Residential district that can promote “craft” industrial uses that are compatible with residential uses.
- Takes sensitive approaches to land use changes that balance the need for housing with the potential for increased development pressure and displacement risk.

The proposed zoning code and design standards allow the types of development that would implement the vision and objectives described in Chapter 3|Concept.

The map below illustrates recommended zoning changes and aligns with the Preferred Alternative studied in the Final Environmental Impact statement.

Map 4-1 Zoning Concept



Note: in the Draft Environmental Impact Statement the zone shown above as "DUC – C-2 Heavy Commercial" was referred to as C-3 Heavy Commercial. During the 2024 comprehensive plan update a zone that had been called C-2 was deleted and the name of the C-3 zone was updated accordingly.

Source: MAKERS.

DUC – Core

The Downtown Urban Center zoning district encourages higher density residential compared to other areas of the city and mixed-use buildings. Other commercial uses are allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. (see Pedestrian Streets) per the City's currently adopted Downtown Design Guidelines.

Building Form

Expected Building Types	Development Standards
▪ Mid-rise apartments ▪ Office buildings ▪ Parking structures	▪ Maximum height 75-125 feet depending on area ▪ FAR based on location, use mix, and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Retail/residential vertical mixed-use ▪ Office commercial ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Restaurants/bars ▪ Craft industry/light industrial ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage and sales ▪ Most industrial uses ▪ Self-storage ▪ On Pedestrian I Streets: Drive-throughs

Development Examples



L-R: Mixed-use buildings in Salem, OR; Seattle, WA; and Kirkland, WA

DUC – Health and Wellness

The Downtown Urban Center – Medical zoning district encourages growth of medical and medical office uses in downtown. High-density residential, mixed-use development and other commercial uses are also allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. This zone is designed to build upon and replace the Residential Office Hospital zone (RO-H).

Building Form

Expected Building Types	Development Standards
▪ Medical/office buildings ▪ Mid-rise apartments ▪ Parking structures	▪ Maximum height 125 feet ▪ Reduced height allowances for non-medical uses ▪ FAR based on use mix and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Medical offices and services ▪ Hospital-related ▪ Office commercial ▪ Retail/residential vertical mixed-use ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Food production, i.e. brewery, coffee roastery ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage and sales ▪ On Pedestrian I streets: Drive-throughs ▪ Most industrial uses ▪ Self-storage

Development Examples



L-R: Office building in Seattle, WA; office/retail mixed-use buildings in Boise, ID, and residential/medical mixed-use building in Seattle, WA.

DUC – Neighborhood Residential

This zoning district is designed to support middle housing types like quadplexes, sixplexes, townhouses, courtyard housing, and small apartment buildings. It is intended to be applied in residential areas of downtown near the core with relatively small lot sizes that could support gradual infill development. Limited nonresidential uses are allowed like live/work medical offices or ground-floor retail.

Building Form

Expected Building Types	Development Standards
▪ Middle housing (including townhouses) ▪ Backyard infill detached houses and ADUs ▪ Live/work offices ▪ Small apartment buildings (up to 20 units) ▪ Small co-living housing	▪ Min lot size 2,000 sf ▪ Maximum height 45 ft

Land Use

Allowed Uses	Prohibited
▪ Single-unit detached, middle housing, townhouses, small apartments, and small co-living housing ▪ Retail under 4,000 sf, including mixed use ▪ Small medical/professional offices	▪ Most commercial uses ▪ Industrial uses

Development Examples



L-R: Small apartment building in Seattle, WA; cottage cluster in Portland, WA; townhouses in Seattle, WA

Flex Residential

The Flex Residential zoning district encourages a mix of uses, including homes, artisan spaces, workshops, small light manufacturing, and commercial.

Building Form

Expected Building Types	Development Standards
▪ Workshops and single-story flexible buildings ▪ Middle housing ▪ Small mixed use buildings ▪ Small co-living housing ▪ Small footprint retail/services ▪ Houses with stores or shops in front	▪ Min lot size 3,000 sf ▪ Maximum height 45 ft ▪ No front setback

Land Use

Allowed Uses	Prohibited
▪ Commercial/light industrial ▪ Residential ▪ Artisan/small workshops/ manufacturing/flex-tech ▪ Vertical and horizontal mixed use ▪ Outdoor storage/sales with screening	▪ Heavy industrial uses

Development Examples



L-R: Small retail office building in Seattle, WA; converted workshop in Bozeman, MT; live/work building in Bozeman, MT.

Zoning Recommendations

DP-LU.2 Adopt proposed zoning changes described on previous pages to:

a. Allow a wider range of housing types.

b. Increase opportunities for market-rate and affordable housing.

c. Attract new commercial uses and increase the number of jobs in Downtown Auburn.

d. Increase live-work opportunities within Downtown Auburn.

DP-LU.3 Review and update design standards to ensure regulations promote compatibility between adjacent land uses. Updates may include:

a. Ensuring buffer (i.e. screening vegetation) between development in new DUC zones where it is adjacent to industrial uses.

b. Consider requiring development within 500' of freeways to locate air-intake for building HVAC systems away from major pollution sources (i.e. highways, major arterials, etc.) whenever feasible and to promote indoor air quality.

c. Consider stricter window and building material requirements in North Downtown to reduce the impacts of noise pollution from the Auburn Municipal Airport.

DP-LU.4 Where feasible, consider landscape buffers between new housing and freeways, and utilize this space for green infrastructure (GSI, urban heat mitigation, etc.)

Urban Form

Key Streets

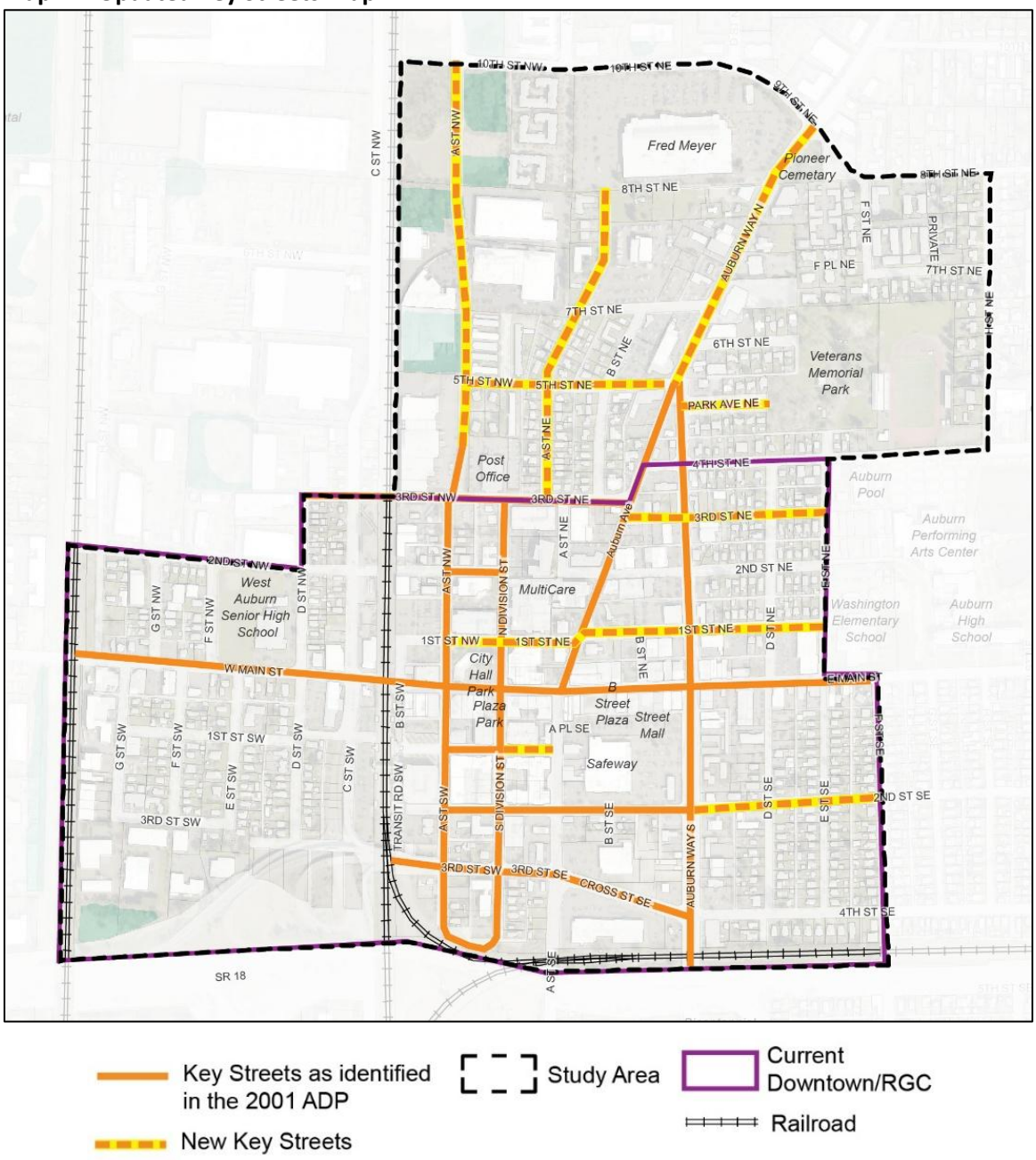
The 2001 Auburn Downtown Plan identified key streets in Downtown Auburn that are "an integral part of the identity of downtown."[4] As in the 2001 Plan, this Plan aims to improve downtown's image identity and cohesiveness through the improvement of street form. The streets identified in the 2001 Auburn Downtown Plan are also within the existing DUC area and include:

- E and W Main St
- A St NW/SW
- Division St
- Sections of the following streets:
  - 1st St SW
  - 2nd St SW
  - 3rd St SW
  - Cross St SE
- A St SE
- Auburn Avenue
- Auburn Way

The key streets framework developed early goals for pedestrian orientation within Downtown Auburn, identified needed investments to support downtown revitalization, and distinguish downtown from other commercial areas in Auburn. With the expansion of the downtown subarea to the north, the 2024 Downtown Plan identifies additional key streets to guide future investment and redevelopment over the duration of the plan. New key streets, show on Map 4-2, include:

- Portions of A St NW in the expanded subarea
- A St NE north of 3rd St NE
- Portions of Auburn Way N in the expanded subarea
- Park Ave NE
- 3rd St NE
- 1st St NE and NW west of A St NW
- 2nd St SE east of Auburn Way S
- 1st St SE (one block)
- C St SW north of W Main St

Map 4-2 Updated Key Streets Map



Source: MAKERS

Design Standards

Following the 2001 Auburn Downtown Plan, the City developed design standards for downtown with the goal of ensuring that new buildings contribute to an inviting, comfortable, pedestrian-friendly environment. These standards cover a wide range of topics, including parking lots, outdoor lighting, trash/service areas, public plazas, design, and signage, with. The standards also encourage creativity and enhancing downtown's unique character.

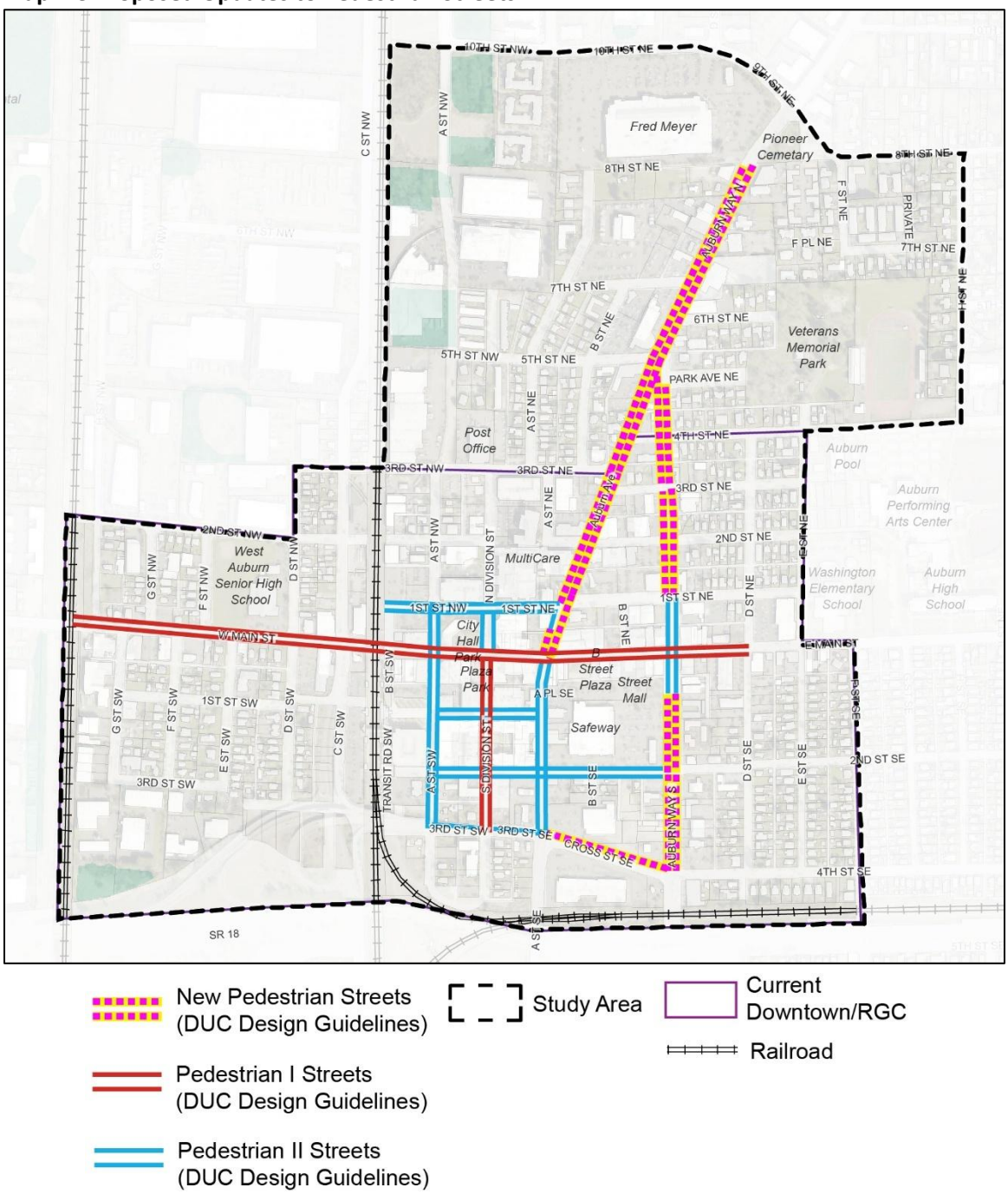
Legislation passed in 2023 (RCW 36.70A.630) requires that cities update their design standards to reduce barriers to housing development. Design standards are now required to be "clear and objective" and must not reduce development capacity. Certain elements of the existing downtown design standards do not comply with these requirements. The standards will be updated for compliance with 36.70A.630; this will also provide an opportunity to review for needed updates, including sidewalk and streetscape standards for new downtown areas, and account for changing conditions and goals downtown.

Pedestrian Streets

Design standards developed to implement the 2001 ADP established new standards for building and site design on designated streets to help achieve a comfortable and attractive street environment for pedestrians. These standards built-on the Key Streets framework and provided guidance for future development. Designated Pedestrian I and Pedestrian II Streets have special rules for key design elements, including driveway and parking locations, ground floor use requirements, orientation to the sidewalk, transparency, weather protection, and signage.

The 2024 Downtown Plan recommends updating both the Key Streets and the Pedestrian Street frameworks to align with the proposed expansion of Downtown. The expansion of downtown to the north incorporates an area with different street and building design patterns than the original downtown. Future updates to downtown design standards should apply pedestrian street designations in this area. Updates may also consider developing a new designation with standards more appropriate to the more auto-oriented, widely-spaced building patterns in the area north of 4th St NE.

Map 4-3 Proposed Updates to Pedestrian Streets



Source: MAKERS

Street Activation

Promoting greater activity and uses of key streets and open spaces is a significant opportunity to increase the vibrancy of downtown.

E Main St (particularly east of A St SE)

- Encourage and expand streeteries and/or outdoor dining options. (See Transportation - Main Street Traffic Analysis for more details on how potential traffic revisions could support this.)
- Encourage stronger art presence along corridor to anchor and support arts district.
- Support festivals.

1st St between Sounder Station Plaza and A St SE

- Promote corridor through art elements.
- As redevelopment happens east of A St SE, continue to activate corridor and strengthen pedestrian and bike connections to the Sounder Station.

Division Street

- Focus on activation (events, arts themes, etc.) and spillover opportunities with plaza spaces.



L-R: Examples of new main street buildings supporting active street environments in Bozeman, MT Bellevue, WA; and Burien, WA.

New Connections

Though many parts of Downtown Auburn have a well-connected street grid, in some North Downtown and West Downtown areas there are offsets in the existing street network. As new development comes to these areas, intersection improvements and strategic non-motorized crossings will be required. Street improvements should support safe and comfortable crossings for people walking and biking.

In areas with larger block structures, through-block connections can also support non-motorized connectivity while also allowing flexibility for future development.

Urban Form Recommendations

DP-LU.5 Update DUC design standards with consideration for areas in North Downtown.

DP-LU.6 Update Pedestrian Streets designations (see Map 4-3).

a. Consider creating a new designation type appropriate for higher-traffic roads like Auburn Way S, with greater flexibility for ground-floor uses and building design, and an increased emphasis on sidewalk and landscape strip design.

DP-LU.7 Require redevelopment to provide strong connections for people walking, biking, and using transit through the construction of new, complete streets, street improvements, and/or new through block connections.

Green Buildings and Urban Resilience

As change and redevelopment comes to Downtown Auburn, there is an opportunity to make progress towards the city-wide sustainability goals which include increasing energy-efficiency in buildings, reducing greenhouse gas emissions, promoting a walkable, livable downtown with strong connections to transit, efficient use of natural resources, enhancing and protecting natural systems, and laying the foundation for a sustainable future for the people who live and work in Auburn.

Reducing GHG Emissions

The 2024 Downtown Plan plays a central role in supporting the City's goals for reducing GHG emissions by recommending increased opportunities for growth downtown, close to transit resources. In addition to these critical land use choices, the 2024 Downtown Plan will also explore opportunities to further reduce GHG emissions downtown, and consider future infrastructure needs to support decarbonatization of buildings and the transportation sector. The following items are most critical to consider for Downtown:

- Promoting the decarbonization of existing buildings and new development within Downtown (Alignment with Goal 17 of the 2024 Comprehensive Plan Climate Element)
- Ensuring adequate EV charging infrastructure within downtown, both in public parking lot locations, and as required with redevelopment.
- Using opportunity site catalyst projects recommended in this plan to demonstrate innovative strategies and approaches for supply and use of energy and heat.

Urban Resilience to Extreme Weather

The 2024 Comprehensive Plan Climate Element identified the following priority climate-related impacts on Auburn:

- Rising temperatures and extreme heat
- Severe storms and flooding
- Drought and wildfires

Each of these will impact Downtown, but extreme heat is acutely felt in urban contexts where there is often a lack of shade and large areas of impervious surfaces that can increase temperatures. Furthermore, Downtown Auburn has a significant population of seniors and elderly residents, who are particularly vulnerable to extreme heat. Priorities for reducing the impact of the urban heat island within downtown may focus on the following.

- Increasing access to shade and green space within the downtown (i.e. on private property and/or 'cool corridor' streets that provide shade, more green space, etc.)
- Reviewing opportunities to promote cooling strategies, such as passive cooling design, green or reflective roofs, and other elements, when updating the DUC design standards.
- Providing access to cooling centers within Downtown (i.e. resilience hubs, which could also provide clean air to offer refuge from wildfire smoke impacts.)

Additional climate strategies for Downtown may include:

- GSI improvements, and potentially innovative approaches with private development, to better manage stormwater and reduce urban heat.

Air Quality

Maintaining healthy air quality is also a key consideration for all urban areas, including Downtown Auburn, given proximity to regional state highways, and arterial traffic within downtown, residents are exposed to pollution from vehicle emissions and tires, as well as noise. The proximity to the Auburn Municipal Airport also adds to local air and noise pollution.

The 2024 Downtown Plan includes recommendations to promote healthier indoor air quality for future residents, including:

- Considering landscape buffers from major arterials, where feasible;
- Locating in-take for building ventilation systems away from key arterials and other pollution sources, when feasible, and;
- Increasing access to air conditioned spaces.

Green Building and Resilience Recommendations

DP-LU.8 Support decarbonization of existing buildings and new development to align with Auburn's climate change goals.

a. Use opportunity site catalyst projects recommended in this plan to promote innovative renewable energy sources for the supply of electricity and heat, passive cooling strategies, green roofs, and other strategies.

b. Support the shift to electric sources of energy within downtown.

DP-LU.9 Promote efficient water use in buildings and landscapes within downtown.

a. Ensure new buildings meet or exceed state-level guidance on water-efficiency.

DP-LU.10 Require water-efficient landscape with new buildings.

DP-LU.11 Reduce the urban heat island effect by:

a. Expanding tree canopy cover outside of right-of-way and increasing green space within Downtown.

b. Update development standards to promote passive cooling, reflective and/or cooling building materials, and other design strategies.

DP-LU.12 Provide a resilience hub in Downtown, that provide access to cool spaces and air filtration during periods of extreme heat and/or wildfire smoke.

DP-LU.13 Support the transition to electric vehicles within downtown.

a. Establish a plan for electric vehicle charging within downtown. (See Transit, Vehicle Circulation and Parking Recommendations)

b. Ensure adequate EV charging infrastructure around new multifamily developments.

5 | Housing & Redevelopment

This chapter identifies how the 2024 Downtown Plan will encourage new housing options and promote redevelopment that can bring new jobs and broad economic benefits to the area. This chapter is divided into four sections:

- Housing
- Redevelopment
- Programs, Funding, and Incentives
- Local Businesses and Displacement Risks

Housing

Encourage Affordable Housing Development

Downtown has seen success encouraging residential and mixed-use market rate development in recent years. The 2024 Downtown Plan recommends targeted updates to development and administrative code to help increase development of more affordable housing as well, including both lower-cost unit types and income-restricted affordable housing. Specific updates include:

- Updating the DUC zone to encourage both naturally-occurring and income-restricted affordable housing may promote more affordable housing downtown.
- Implementing the Housing Action Plan recommendations to help reduce the cost of newly constructed units, including parking reductions for affordable housing and micro units, increasing allowed FAR for affordable housing, and creating fee-waivers for affordable housing.
- Updating regulations to allow co-living, a type of market rate affordable housing, as required by HB 1998 (passed in 2024).

Encourage Middle Housing

Middle housing offers a broad range of benefits in terms of affordability, unit type variety, ownership-opportunities, and human-scaled design. Existing nonconforming middle housing buildings are already present throughout downtown, constructed before the application of modern zoning. The recent effort to study feasibility and development constraints for the Housing Action Plan Implementation Strategies (HAPI) report offers important recommendations to allow and encourage development of middle housing in residential zones where it is currently not permitted or financially infeasible to produce.



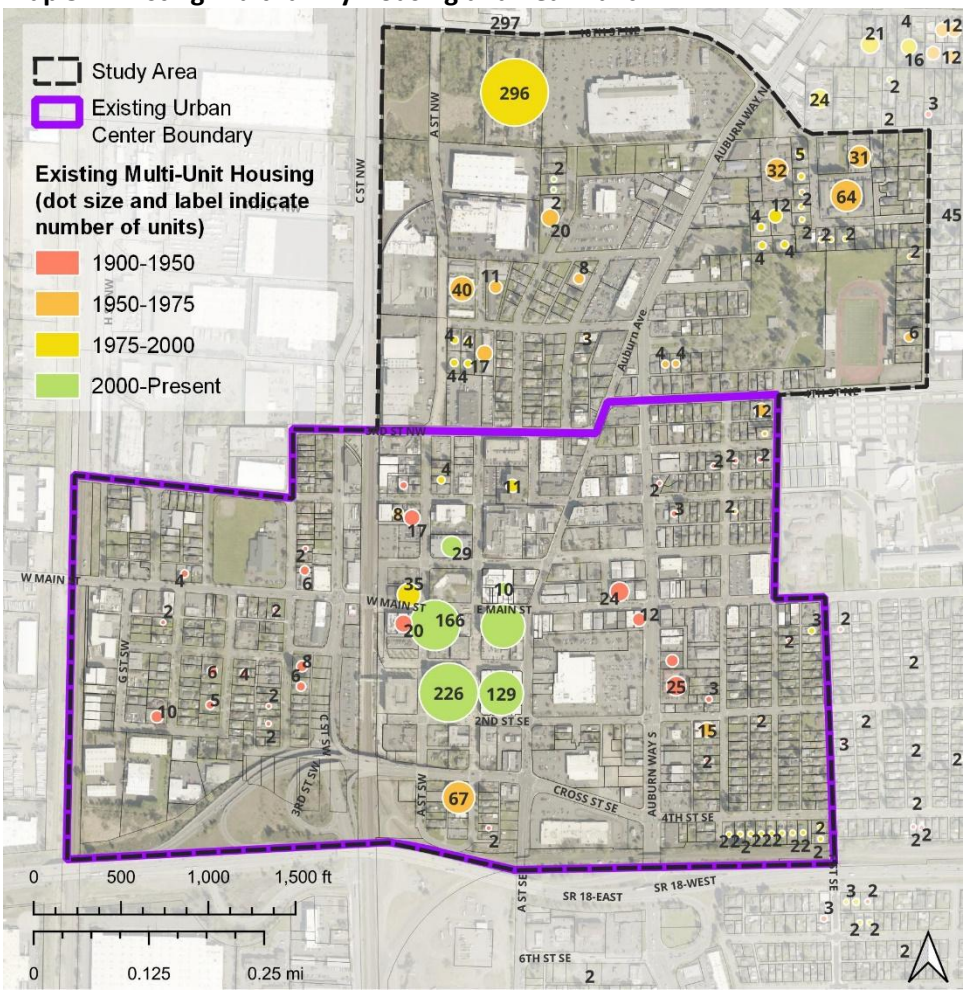
L-R: Existing nonconforming triplex, six-plex, and duplex in downtown Auburn. Source: Google Street View © Google

Protect Existing Dense Housing

Regulated affordable housing typically makes up a relatively small share of housing affordable to low- and moderate-income people. Instead, homes that are affordable at market rates are known as "naturally occurring affordable housing" (NOAH). These are often older buildings which may not include amenities required by current zoning code, such as on-site parking or open space.

In recent years most new housing development in downtown has occurred at formerly vacant or commercial properties. However, as development activity expands outward from the core area, existing NOAH resources may be at risk of redevelopment, with new development likely charging higher rents, leading to displacement. Care should be taken not to incentivize the redevelopment of NOAH sites when revising development regulations, zoning, and programs that encourage housing development. The map on the following page shows the location, size, and date existing multifamily buildings in downtown Auburn were built.

Map 5-1 Existing Multifamily Housing and Year Built



Source: King County Tax Assessor 2022, MAKERS

Update Zoning for Housing Abundance

The primary cause of rising housing prices is restricted supply. At the same time, certain types of housing tend to be more affordable because they're more compact and/or share the cost of land across a greater number of units. Downtown Auburn, with good access to transit and amenities, is an ideal place to increase housing capacity to help address scarcity. Zoning updates in downtown ensure that relatively affordable types of housing, like apartments, are allowed to be built.

Modify the City's Existing MFTE Program

Auburn currently has a Multifamily Tax Exemption (MFTE) program found in Auburn City Code 3.94, as authorized under RCW 84.14. This program allows qualifying developments to be exempt from taxation on the value of new construction, rehabilitation, and improvements of multifamily housing containing four or more units in the targeted area. Currently, the targeted area comprises the existing RGC boundary. The exemption lasts eight years for market-rate projects, or 12 years if 20 percent or more of the units are available to low-income households (earning under 80 percent AMI) or moderate-income households (earning 80-115 percent AMI). Twelve-year projects require an average minimum investment of $130,000 per year per unit, whereas 8-year market rate projects do not have a minimum per unit investment. In the current DUC zone, properties must have a minimum of 50 units to qualify for the program.

In Auburn's Housing Action Plan, affordable housing in the Downtown area was identified as a key priority for the City. An analysis of land values and costs of development using a 12-year MFTE program with affordable units provided at 80 percent AMI showed that such projects would likely be considerably more feasible in terms of residual land value than other development types given land values at the time of that plan's adoption in June 2021. Although the market has changed over the past two years, land values in the Downtown area are consistent with the analysis in the HAP which indicates that a 12-year MFTE program can be a significant catalyst for multifamily projects which include affordable units in the Downtown.

There are several possible strategies for updating Auburn's MFTE program to help encourage use of the program, expand its potential outcomes, and align more closely with recent legislative changes. The 2024 Downtown Plan recommends revising the City's MFTE program with the following:

- Expand MFTE Program to full Study Area.
- Consider revising unit minimums based on updated Downtown zoning.
- Remove "High Cost Areas" from MFTE definitions.
- Consider ground floor commercial requirements or agreements in key locations where a strong pedestrian-oriented environment is desired.
- Continue to track usage of the MFTE program.

Housing Recommendations

DP-H-1 Update the Downtown Urban Center Zone to encourage more affordable housing (see DUC – Core):

a. Create a fee waiver and FAR bonus for affordable housing in DUC zones.

b. Reduce required parking for affordable housing and micro-units

c. Provide a FAR bonus for affordable housing.

d. Allow co-living in all DUC zones that allow residential.

DP-H-2 Revise citywide residential zoning through the comprehensive plan process to incorporate middle housing types and apply appropriate zones in downtown.

DP-H-3 Implement HAPI recommendations generally, including updated definitions, zone intent, permitted uses tables, dimensional standards, parking requirements, and internal conversions.

DP-H-4 Ensure zoning updates allow apartments in all downtown residential zones.

DP-H-5 Update the City's MFTE program to encourage greater flexibility and use by doing the following:

a. Expanding the MFTE Program to the Revised Downtown Area, to include North Downtown

b. Revising unit minimums based on updated Downtown zoning.

c. Removing "High Cost Areas" from MFTE definitions.

d. Reviewing ground floor commercial requirements or agreements in key locations where a strong pedestrian-oriented environment is desired.

e. Continuing to track usage of the MFTE program.

DP-H-6 Continue using the Affordable and Supportive Housing Sales Tax Credit Fund for acquisition, rehabilitation, and construction of affordable housing; operations and maintenance costs of new affordable or supportive housing units; and rental assistance provisions to tenants.

DP-H-7 Prioritize conservation of Auburn's existing housing stock in the Neighborhood Residential District of the downtown because it is the most affordable form of housing.

DP-H-8 Promote the maintenance, energy efficiency, and weatherization of existing affordable housing stock through City funded and operated program(s).

DP-H-9 Allow density bonus if first right to return policy that prioritizes members of the community is offered in new affordable housing developments.

DP-H-10 Allow for nonconforming single-family residential homes, middle housing, and their accessory structures may be replaced and the new structure shall either meet the development standards of the district in which the home is located or the new structure shall not be more nonconforming than the previous use.

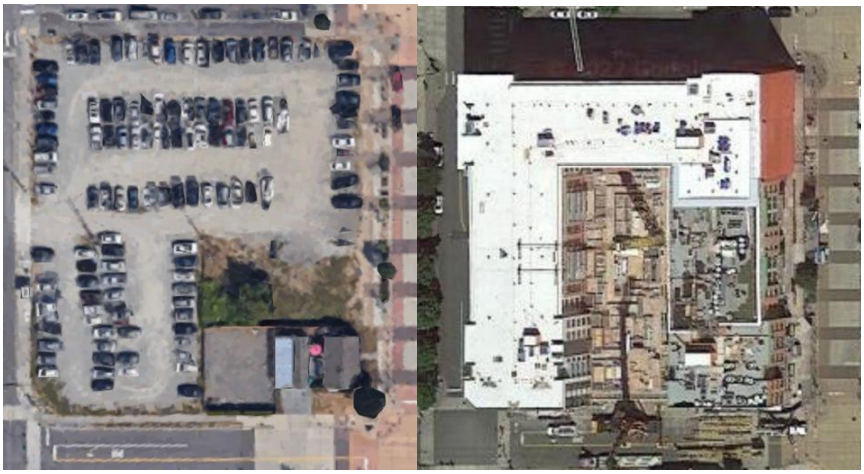
Redevelopment

Opportunity Sites

Key sites in Downtown Auburn could help catalyze future development in the area and/or serve as important redevelopment projects in the Downtown landscape. The City currently owns several sites which could play a key role in catalyzing redevelopment of the area. Additional sites could also serve as catalysts, as opportunities arise.

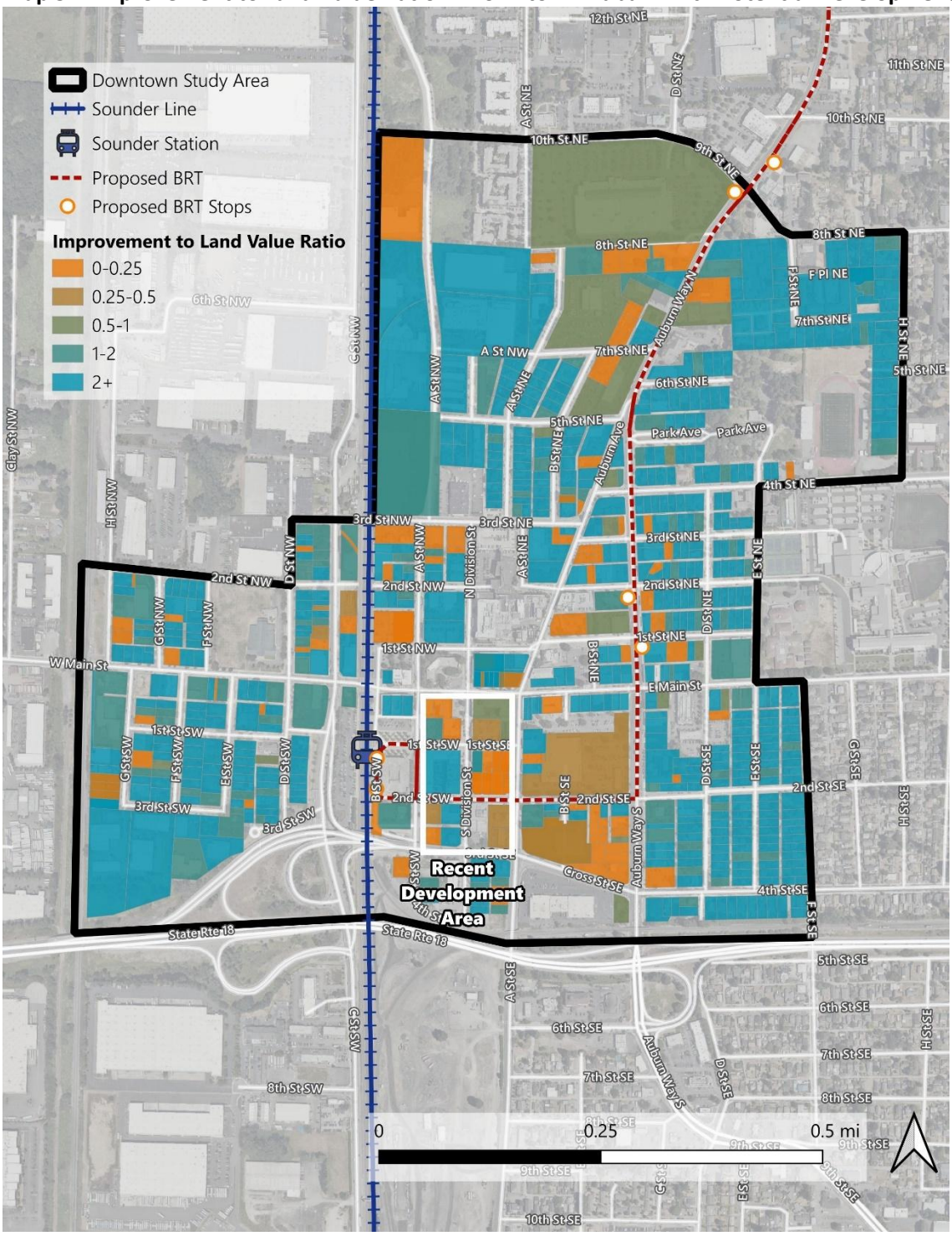
Map 5-2 below shows the relationship between the building (improvement) value and the land value in the downtown Auburn study area. This ratio can help to identify sites that are likely to redevelop if the value of the land is substantially more than the value of the building (i.e., a ratio below 1.0, shown here in shades of orange and brown). Sites with ratios above 1.0 (shown in shades of blue) are less likely to redevelop due to the value of the building. The map also shows potential for development activity to shift from the core area towards other areas with clusters of underutilized parcels.

In the Downtown Core, there are several blocks directly to the east of the most recent developments which are showing a low improvement-to-land value ratio. This area currently contains a Safeway and an auto parts store, both surrounded by a significant amount of surface parking. Of note, several recent projects in Auburn including Legacy Plaza and The Verge were developed on similar sites previously occupied by surface parking, as shown below.



The Verge Apartments before and after development. Source: Google Earth

Map 5-2 Improvement to Land Value Ratio in Downtown Auburn with Potential Development Areas



Source: King County Assessor, Leland Consulting Group

Several Safeway sites throughout the Pacific Northwest have redeveloped from single-story supermarkets into multistory mixed-use projects while retaining the Safeway on the ground floor. The Museum Place development in Portland, shown in the top image below, replaced an old single-story Safeway with a new mixed-use development across the street containing 140 loft-style apartments, a 48,000 square foot Safeway, and 220 structured parking spaces. It was financed through a mix of public and private financing and opened in 2002. Several such projects are currently underway in the Seattle area, including a large, proposed development in Capitol Hill which would replace an existing Safeway with 330 market rate units, a new Safeway, and other supplemental small retail areas. Another such project is planned for the Safeway in Seattle's Queen Anne neighborhood.





Top: Museum Place Safeway, Portland, OR Source: Shiels Obletz Johnson
Bottom: Proposed Safeway in Capitol Hill, Seattle Source: Capitol Hill Seattle

These projects demonstrate the potential for Auburn's Safeway site to better capitalize on its Downtown location with mixed-use development while retaining the important grocery store use for the community. Additionally, this site could represent an opportunity to repurpose some of the parking for open space or connection to an improved pedestrian greenway on 1st or 2nd St, depending on the parking configuration of a redevelopment concept.

In the northern area of Auburn's Downtown, there is also a cluster of large, underutilized sites south of Fred Meyer. These may be potential candidates for redevelopment, particularly in light of the forthcoming King County Rapid Ride I line slated to begin service in 2025, with a stop directly adjacent to the Fred Meyer. With the potential expansion of the RGC to include the northern area of Downtown and the regional policy priority for density around high-capacity transit, this area could be well positioned for denser uses.

In addition to these clusters of well-located, underutilized properties, there are other "opportunity sites" in the Downtown area. There are a number of large and mid-size commercial properties in downtown. Most have large surface parking areas that reflect parking ratios desired by commercial tenants in the mid- to late-20th century. In the short and medium term, businesses on these sites may continue to operate as they have in the past. However, looking over a 20+ year time horizon, these sites appear to offer redevelopment opportunities that can accommodate more mixed-use development. Some of the buildings will reach the end of their lifespan and the sites can be redeveloped in a way that reflects their highest and best use—as denser, mixed-use projects. Some existing tenants can be brought back into new mixed-use projects as ground floor tenants.

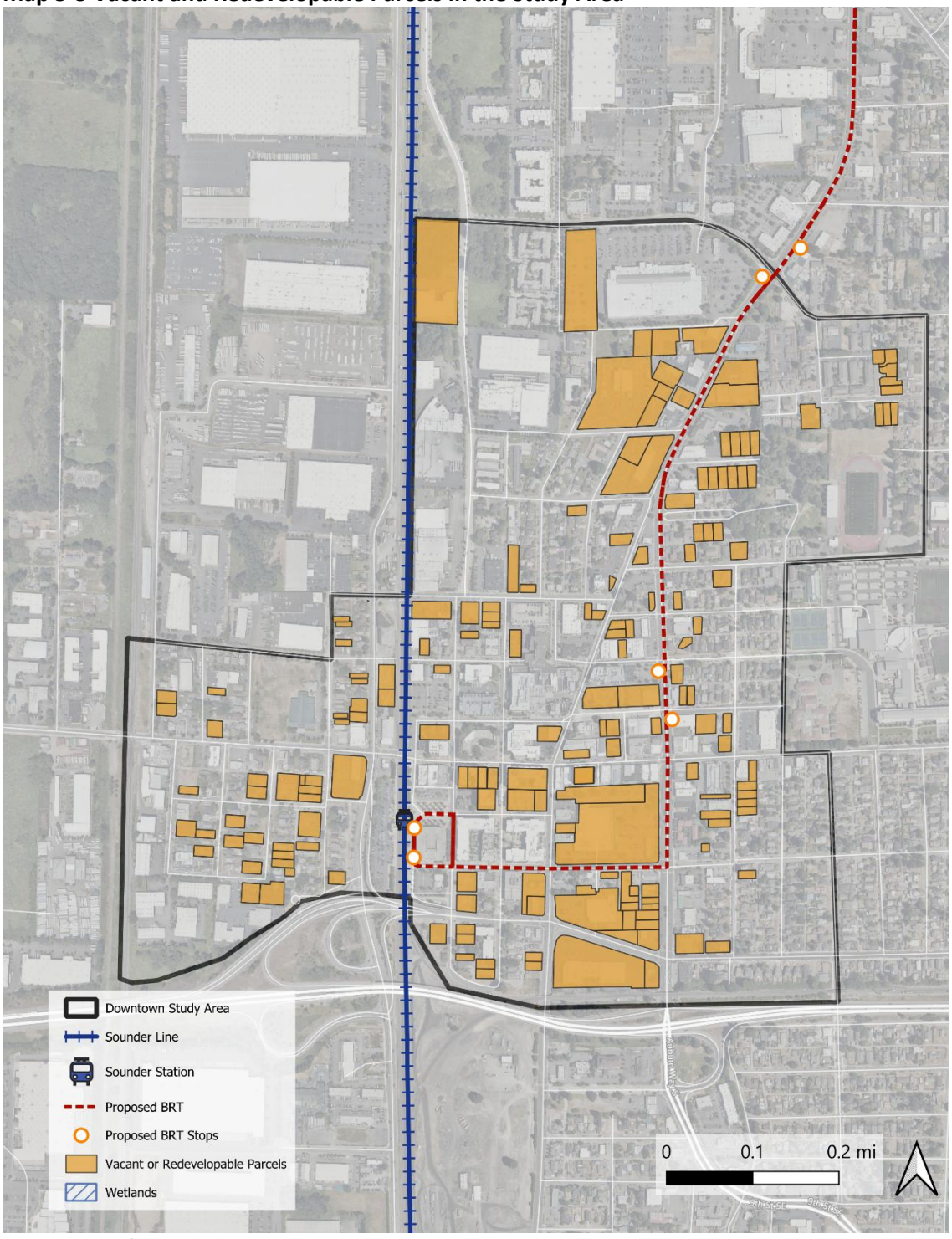
DP-H-11 Update design standards to promote more flexibility, particularly for ground floor commercial spaces, to promote a wider range of businesses. Potential strategies include:

a. Flexible ground floor layouts to accommodate different and growing businesses;

b. Commercial ground floor requirements that can accommodate a range of uses (high-ceilings for ventilation to support cafes/restaurants, etc.); and

c. Consider maximum retail sizes (outside of grocery, hardware, etc.).

Map 5-3 Vacant and Redevelopable Parcels in the Study Area



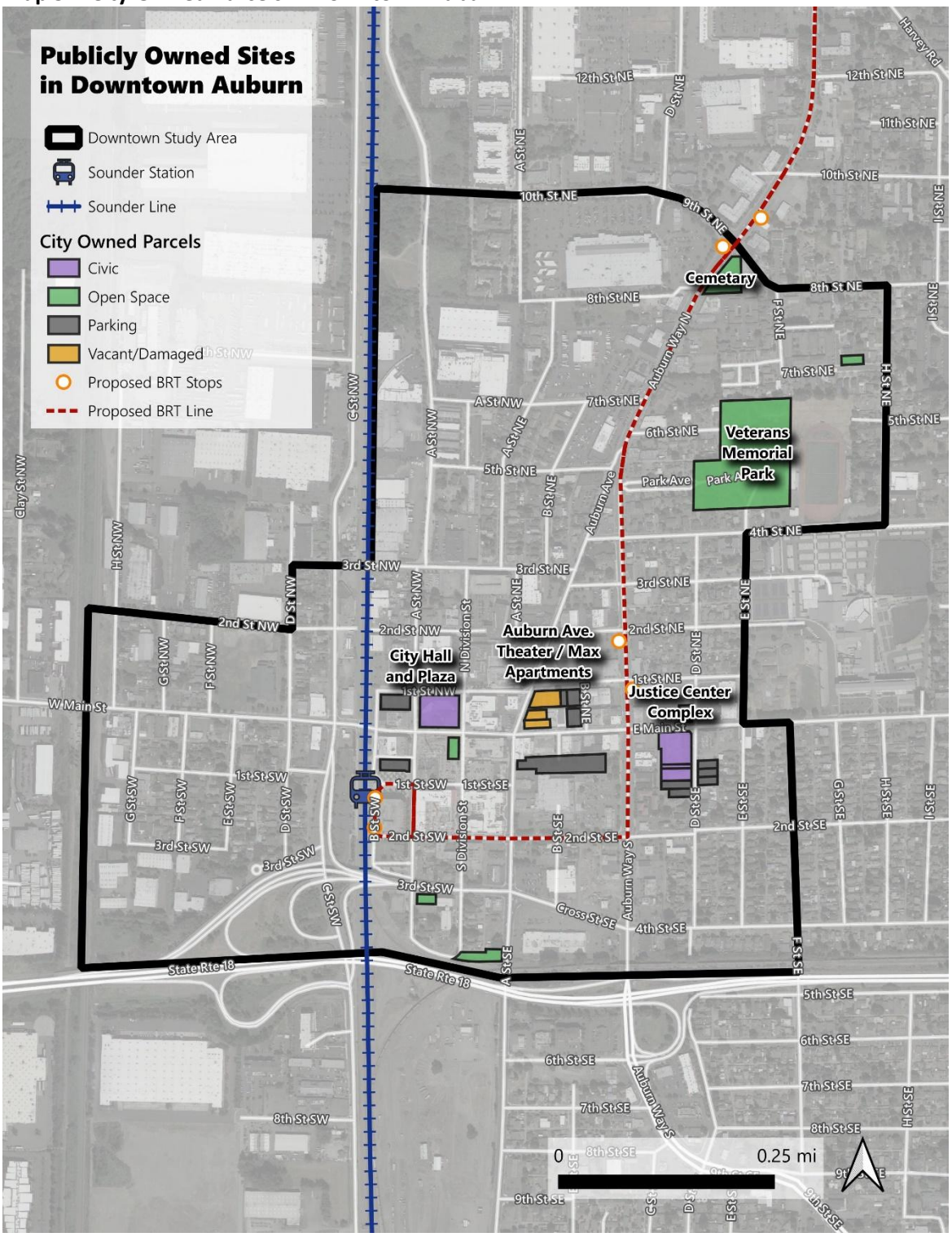
Source: City of Auburn, Leland Consulting Group

City-owned Opportunity Sites

The City of Auburn owns several key sites in the downtown on which redevelopment could take place; current locations (2025) shown on Map 5-4. The City-owned former Auburn Avenue Theater and former Max Apartments site presents a significant opportunity for the city, as the vision is to recreate a theater along with arts-focused ancillary development. Implementation of this type of project can be complex and sometimes challenging, so ongoing planning may be needed to realize this vision. Other City-owned properties, such as surface parking lots north and south of E main Street between A Street and Auburn Way, could offer additional sites for new development, or could continue to serve as surface parking. These property assets will enable the City to play a significant role in guiding Downtown's development in the coming decades, through renovations, modifications, and/or major redevelopment projects.

See also the Programs, Funding, and Incentives section in Chapter 5| for more details on funding considerations.

Map 5-4 City-Owned Parcels in Downtown Auburn



Source: City of Auburn, King County, Leland Consulting Group

Key Districts

Arts and Culture Hub

With notable energy around arts and cultural events in the City of Auburn and the City's recent investment in the Postmark Center for the Arts, and the Auburn Ave Theater and former Max Apartments properties near Auburn Ave and E Main St there is an opportunity to expand this area into an arts district and catalyze new investment and growth.

There is a state program that can support efforts, and provide technical assistance and marketing to help kickstart opportunities. (https://www.arts.wa.gov/creative-districts/) Communities can also form their own arts districts, to encourage local interest in the arts, and promote economic development and community revitalization. When supported by active local arts commissions, these districts can be successful in forming and maintaining creative arts centers.

Affordable housing for artists is also a key need and opportunity to bring new vibrancy and housing opportunities into the area.



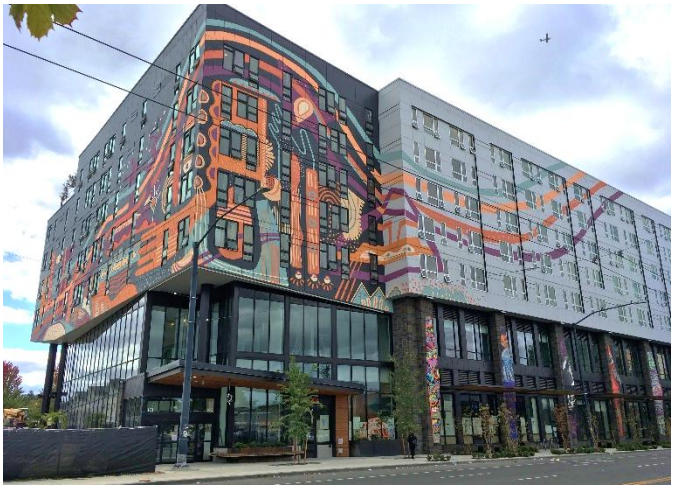
Art installations on E Main Street.

Encouraging Medical/Wellness Uses

Encouraging new medical and wellness uses around MultiCare could help build on this key employment center and regional asset by providing companion uses, expanded outpatient clinic, and other health-related services. Ongoing coordination with MultiCare can help the City identify potential partnership opportunities, areas of overlap with health service and community needs.

Recent developments in the region highlight the shift that some medical institutions are making toward community-oriented facilities and integrated health and community services. The Odessa Brown in Seattle's Othello neighborhood, operated by Seattle Children's is one such example. The new building combines medical and dental care with physical therapy and sports medicine office, a kitchen, and a half basketball court for indoor recreation, and is based on the Social Determinants of Heath model, which highlight the importance of elements like housing, access to education, social and community

ties to overall health and well-being.[5] The building also includes several floors of apartments above the clinic. Visually striking with public art that relates to the local community and a strong pedestrian-orientation, the building is a successful example of a mixed-use development centered around health.



Odessa Brown Children's Clinic and mixed-use building in Seattle's Othello Neighborhood

The Oregon Health and Science University (OHSU) campus in Portland's South Waterfront neighborhood is another example of how partnerships and early investments can lead to significant redevelopment over time. The first redevelopment, OHSU's Center for Health and Healing, was completed in 2006 and OHSU has further expanded its campus in the area over the last 20 years. Additional investment followed, resulting in an estimated $3 billion dollars in new development.[6] Planning and implementation was centered not only on the private health investments, but also public transit investments and significant public private partnerships.



OHSU anchors redevelopment in Portland South Waterfront neighborhood.

Promoting Redevelopment Recommendations

DP-H-12 Continue to promote development sites and seek partners.

[5] https://health.gov/healthypeople/priority-areas/social-determinants-health
[6] http://www.alamomanhattan.com/portfolio/block-45

DP-H-13 In the medium-term (next 1-3 years), the City should define a plan for redevelopment. Begin to seek grant funds, and/or nonprofit or private development partners in order to implement the defined and desired development. If one or more stand-alone arts venues are not being pursued, then other options should be considered and implemented to avoid long-term vacancy of the sites.

DP-H-14 Market the benefits of the Planned Action EIS such as reduced SEPA review and risk for developers.

DP-H-15 Highlight importance of Arts to Downtown Auburn by:

a. Continuing to support local public art program.

b. Fostering Arts Commission to generate local interest and opportunities for the arts.

c. Explore potential for forming an Arts District in downtown by creating a local district or pursuing state programs.

d. Build on recent investments around the Postmark Center for the Arts.

e. Pursue mixed-use project that combines affordable housing and arts and/or performance space on City-owned properties in this area.

f. Leverage Main Street traffic revisions to accommodate more active art events in this space.

g. Work with local partners and businesses to support arts-themed events (Sound Transit, MultiCare, etc.)

DP-H-16 Encourage new types of businesses in Downtown that provide new activities, including new restaurants, arts-related spaces, etc.

DP-H-17 Continue to monitor redevelopment and permit activity and work with developers to ensure the 2024 Auburn Downtown Plan's goals are being met by new development in the area.

DP-H-18 Actively facilitate projects in key locations:

a. Large and mid-sized commercial properties

b. North Downtown

DP-H-19 Identify incentives to address storefront vacancies.

DP-H-20 Consider establishing vacant building regulations and/or a registration program with maintenance and upkeep requirements for vacant storefronts to ensure that the condition of empty buildings located downtown is maintained at a certain minimum level.

DP-H-21 To ensure vibrant streetscape and avoid adverse impacts on neighborhood character, consider regulations for window displays for vacant storefronts that remain unoccupied for 6 months, for all ground-floor windows that face sidewalks, streets, or public open space.

DP-H-22 Promote the temporary use of a vacant storefront, when it is not possible to fill up a vacant downtown storefront with an active business on a permanent basis, including but not limited to pop up shops, arts installations, and seasonal events, and "makers markets".

DP-H-23 Develop a plan to prioritize action on other City-owned sites. Key steps may include:

a. Identify staff to oversee a feasibility analysis of existing City-owned parcels to evaluate best opportunities for redevelopment.

b. Consider parking utilization and future electric vehicle charging infrastructure needs when assessing existing parking lots for redevelopment.

c. Sharing information on the City's website.

DP-H-24 Promote Medical-Wellness hub around MultiCare by considering the following:

a. Continue to work with MultiCare to identify future goals and partnership opportunities to expand and enhance medical-well uses around the existing medical center.

b. Consider opportunities to cluster uses that complement medical services and support greater health and wellness outside of strictly medical uses

c. Review DUC design standards in this area.

DP-H-25 Update design standards to promote more flexibility, particularly for ground floor commercial spaces, to promote a wider range of businesses. Potential strategies include:

a. Flexible ground floor layouts to accommodate different and growing businesses;

b. Commercial ground floor requirements that can accommodate a range of uses (high-ceilings for ventilation to support cafes/restaurants, etc.); and

c. Consider maximum retail sizes (outside of grocery, hardware, etc.).

Programs, Funding, and Incentives

There are a variety of funding and incentive opportunities which can help stimulate and fund business activity and development in Auburn's downtown, both City- and State-operated. These programs are highlighted below and followed by recommendations for updates to some of these initiatives and additional funding and incentive sources for the Downtown.

Existing City Programs

The City of Auburn provides several incentives for businesses in the Downtown Urban Center, including:

- The Multifamily Tax Exemption (see Housing in Chapter 5|for update details)
- Staff-level design review of development applications
- Business Improvement Area (BIA)
- Storefront Auburn Program
- Access to federal New Market Tax Credits
- Coordination with other existing organizations

The City should continue to offer such programs and opportunities. The DUC zone already provides for staff review of applications to expedite permitting and design review, and such policies should be continued as some areas of the downtown are rezoned as part of this planning process.

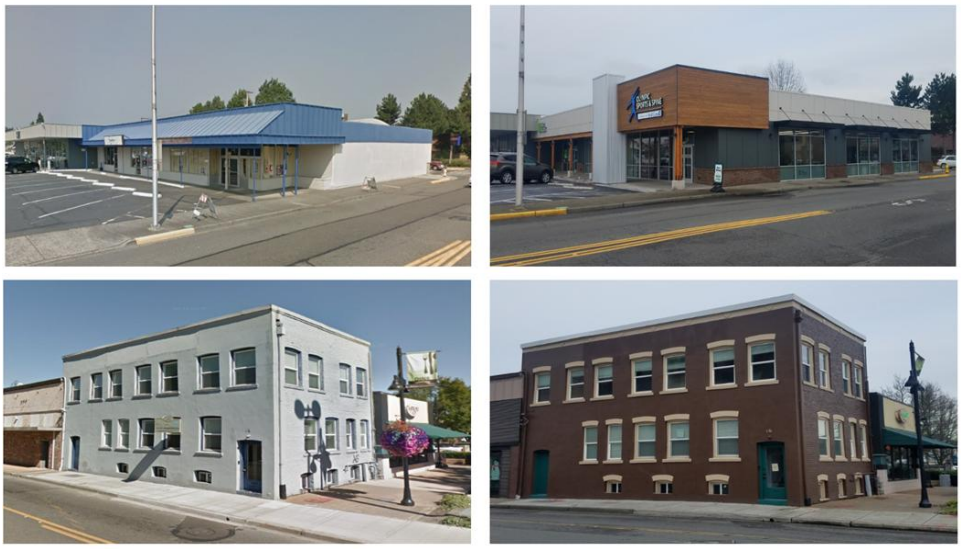
Storefront Auburn Program

The City of Auburn has historic and unique buildings, as well as many wonderful family-owned and compelling businesses. The Storefront Auburn Program seeks to preserve and enhance the charm of the Downtown commercial area through strategic physical improvements to buildings.

The City is awarding façade improvement grants to facilitate exterior building (façade) improvements for businesses within the designated Business Improvement Area (BIA). Since 2015, the City Council approved $100,000 per year to be awarded to owners of buildings and/or businesses in downtown Auburn. The 2024 Downtown Plan recommends the City continue these efforts to create favorable conditions for businesses in the downtown area.

Auburn's program covers the costs of improvements under $5,000 and requires a gradually increasing match for more expensive projects, with a maximum grant of $30,500. The business must be within the Business Improvement Area and employ 25 people or fewer, and newly constructed buildings are not eligible.

Images below provide examples of historic and mid-century buildings revitalized under Auburn's program. The 2024 Downtown Plan recommends the City explore whether this grant program can be expanded so that grants can be made to address internal and/or building envelope improvements, such as grants for commercial kitchens, heating and cooling, structures, roof repairs, etc. Additionally, the 2024 Downtown Plan recommends considering increased funding for this program, and in particular targeting businesses along the historic Main Street corridor, which was identified by stakeholders as a unique asset within Auburn.



Before and After Storefront Improvement Examples in Auburn. Source: City of Auburn
Source: City of Auburn

New Opportunities

Tax Increment Financing

In 2021, Washington State granted new powers of tax increment financing (TIF) to the state's cities, counties, and port districts.[7] This funding mechanism allows municipalities to establish a geographic district (called the increment area) that is expected to benefit the most from a proposed new infrastructure investment. Typically, bonds are issued at the outset and the additional tax revenue resulting from the increased land and property values are then captured to pay for the new infrastructure and pay off the bonds.

TIF is widely used in other states across the country, but Washington's new program has some specific guidelines which differ from other states. In Washington, the state school levy and some other local taxes used to repay general obligation bonds are exempt. Additionally, TIF financing can only be used for specific authorized public improvements which are expected to

[7] "Tax Increment Financing (TIF)". Municipal Research Service Center. https://mrsc.org/Home/Explore-Topics/Economic-Development/Financing-Economic-Development/Tax-Increment-Financing.aspx

encourage private development and increased assessed valuation which would not otherwise happen without the improvements. These improvements may be located inside or outside the increment area and include streets, water and sewer systems, sidewalks, streetlights, parking facilities, parks and recreational areas, broadband service, or brownfield mitigation. TIF can also be used to pay for long-term affordable housing, childcare service, providing maintenance and security for public improvements, and acquiring property for historic preservation. Unlike in other states, TIF funding in Washington can only be used for the specified projects or improvements set forth in the initial application, and project lists cannot be modified later. Thus, TIF is only applicable to existing and well-defined projects with specific infrastructure needs. The TIF district must have a maximum sunset date of 25 years and not have an assessed valuation greater than $20 million, and each city may not have more than two districts.[8]

In Auburn, projects on City-owned property might benefit from TIF funding. Redevelopment of other parking lot sites, or larger-scale projects requiring new streets, plazas, or streetscape improvements and which also include affordable housing could also benefit from TIF funding.

State Programs

There are several state programs in which the City could participate to enhance downtown economic activity and revitalization as well as tie in with other projects including the Auburn Ave. Theatre redevelopment.

Creative Districts[9] are found in cities throughout Washington and are designated cultural hub areas which can help attract artists, creative businesses, and promote the creative identity of an area. In creative districts, ArtsWA (Washington State Arts Commission) administers resources, grant opportunities, and technical assistance to cities to help promote marketing, placemaking, and development, including affordable housing for artists and redevelopment of historic assets, in these areas.

The Washington State Main Street Program helps communities revitalize the economy, appearance, and image of their downtown commercial districts using the successful Main Street Four-Point Approach. While this approach has usually been applied to historic downtown districts, it also has applicability to commercial corridors such as Auburn Way.

[8] "Washington State's Expanded TIF Authority Creates Powerful Catalyst for Public-Private Partnerships." Denis Wright Tremaine. May 2022. https://www.dwt.com/insights/2021/05/washington-state-tax-increment-financing-law

[9] https://www.arts.wa.gov/creative-districts/

Organizations and Partnerships

Auburn has an existing nonprofit business organization, The Downtown Auburn Cooperative, which https://downtownauburncooperative.org works to improve and create opportunities for small businesses in the downtown.[10] Many of the strategies discussed in this chapter and in Chapter 4|Land Use & Urban Design could be undertaken, at least in part, by this organization. The 2024 Downtown Plan recommends the City maintain an active relationship with the Cooperative and consider providing funding to the organization, particularly for programs or projects in which they are working in partnership. One concern voiced by members of the cooperative in stakeholder interviews conducted by the project team in 2022 was around increased crime and perceptions of safety issues downtown by residents and customers. This could be an area for cooperation between the Cooperative and City works to improve and create opportunities for small businesses in the downtown.[11]

Continuing to engage with local and regional employers, institutions, regional agencies, and Tribal governments can help identify future opportunities and potential partnership strategies. Examples include, but are not limited to: MultiCare, Auburn School District, Green River College, Boeing, Safeway, Fred Meyer, Trillium Employment Services, King County agencies (including Public Health, which has a location just north of 10th St NE), and the Muckleshoot Indian Tribe.

Programs, Funding, and Incentive Recommendations

DP-H-26 Consider using TIF as a funding mechanism in the Downtown for specific projects.

DP-H-27 Maintain and expand existing City programs to support local businesses and address storefront vacancies.

a. Maintan theStorefront Auburn Program and explore feasibility of extending the program beyond façades, to address overall building envelope needs, and other improvements.

b. Consider increasing funding for the Storefront Auburn Program program.

DP-H-28 Consider implementing a Commercial Vacancy Tax.

DP-H-29 Develop a mix of incentives and penalties that seek to eliminate ongoing vacancy of ground floor commercial spaces.

[11] https://downtownauburncooperative.org/

DP-H-30 Consider participating in state programs that align with the key goals of specific areas within downtown, including:

a. Apply for Downtown Auburn to become a designated creative district through ArtsWA. (See Key Districts)

b. Explore opportunities and resources in the Washington State Main Street Program.

DP-H-31 Coordinate with the Downtown Auburn Cooperative (DAC), and other organizations, and seek to develop partnerships to improve security and promote new economic opportunities.

DP-H-32 Continue to seek coordination and partnership opportunities with other major employers, institutions, and the Muckleshoot Indian Tribe located in and around downtown Auburn.

DP-H-33 Consider expanding access to economic opportunities through actions such as adopting a priority hire ordinance, encouraging workforce development partnerships, and identifying pipeline education or training opportunities.

Local Businesses and Displacement Risks

Displacement is most frequently discussed in the residential context, where residents of an area are forced to relocate due to redevelopment or rapid increases in rents and housing costs as an area revitalizes, gentrifies, or redevelops. Although less frequently discussed, the process of displacement can also apply to businesses, particularly small businesses, in areas of redevelopment. Numerous studies have demonstrated the importance of small businesses in the American economy, with the Small Business Administration noting that businesses with 10 or fewer employees make up three-quarters of the nation's private-sector employers.[12] Neighborhood small businesses are important for community gathering and cohesion as well as providing local employment. In many communities, particularly lower- and middle-income areas, small businesses tend to be owned by immigrants and/or people of color.

Despite the negative impacts that can be caused by commercial and residential displacement, it is also true that cities are in a constant, if often slow, process of change and evolution. New people, investment, development, and businesses can also have many positive impacts, including introducing more foot traffic,

[12] [1] U.S. Small Business Administration. (2020). Frequently asked questions about small business. https://cdn.advocacy.sba.gov/wp-content/uploads/2020/11/05122043/Small-Business-FAQ-2020.pdf

safety, and overall spending in an area. The 2024 Downtown Plan calls for more mixed-use development and overall revitalization. Therefore, policies should attempt to balance the positive impacts of development with negative impacts, including commercial displacement.

Small businesses can be vulnerable to several types of commercial displacement:

- **Physical Displacement** occurs when businesses are forced to relocate due to building sale, renovation, or redevelopment.
- **Economic Displacement** occurs when businesses can no longer afford their rent due to rising property values and rents in the area.
- **Exclusionary Displacement** occurs when businesses cannot afford to move into a neighborhood experiencing rapid economic change and consumer preferences.

In Downtown Auburn, there are several areas with businesses which may be prone to displacement. Main Street, described above under "Downtown Core," contains a variety of small businesses in historic buildings, some of which cater to a diversity of cultural groups. This area has already seen a significant amount of redevelopment in recent years. Although many of the new developments contain ground floor commercial space, the new spaces rent for higher rates and may not cater to the needs of the businesses which previously occupied the area.

Another corridor in the Downtown area which may be at some risk of commercial displacement is the section of Auburn Way north of MultiCare, which contains a variety of auto-oriented commercial uses, some of which are vacant or in disrepair. Many of these sites are significantly underutilized with large quantities of surface parking. As the area continues to develop, this area will likely see increased densities and some pressure to redevelop these uses into denser development types, though the MAKERS team projects that the pace of change on Auburn Way will be incremental and modest. Older strip malls, and other aging commercial spaces are typically the most affordable to small businesses. As old retail spaces are redeveloped into mixed use developments, the number of retail spaces affordable to local business owners could be reduced over multiple decades.

Stakeholder interviews with business leaders in Auburn conducted by MAKERS and Leland Consulting Group (LCG) in 2022 indicated that the majority of businesses in the downtown are small, "mom-and-pop" businesses, and there was a general consensus that rents in the area are too high for many of these types of businesses to afford in the Downtown area, even with the increased numbers of residents that new development has brought downtown.

Commercial Displacement Tools

The Small Business Anti-Displacement Network has produced a **toolkit** with strategies cities can use to reduce the risk of small business displacement. A number of these strategies, highlighted below, may be effective in helping mitigate commercial displacement in Auburn.

Commercial preservation and property improvement

Strategies to preserve and improve properties include the City's Storefront Auburn Program, discussed in detail above, as well as programs which provide grants, technical assistance, and/or marketing to help keep designated legacy businesses in an area. Auburn could consider such efforts if specific businesses the City wishes to see remain in the Downtown area are at risk of displacement.

Downtown Associations and Campaigns

The Downtown Auburn Cooperative (DAC), described in detail above, is well positioned to advocate for small businesses in the downtown. Further partnerships between the City and the DAC, or funding of the Cooperative, could help prevent commercial displacement in the downtown area.

Create and Sustain "Shop Local" Campaigns

Campaigns to promote shopping at small local businesses have been successful in bringing economic activity and attention to small businesses in downtown areas across the country. "Small Business Saturday" in November generated over $20 billion for small retailers and restaurants in 2021. Small businesses can work together to promote such campaigns, improve their online marketing presence, and secure funding from private and public sources. A recurring yearly or quarterly event can help sustain customer interest and visibility of Downtown businesses. More tools for "Shop Local" campaigns can be found at Main Street America's website.

Local hiring and entrepreneurial support

Technical assistance and counseling

Technical assistance programs can target BIPOC, immigrant-owned businesses, and other small businesses and can provide assistance with business planning, accounting, and tax filing, as well as language assistance. The City could work with the DAC to provide such services to small businesses in the Downtown area.

Neighborhood business incubators

These often take the form of free or low-cost spaces, mentorship, and/or access to capital for emerging small businesses. The City's Storefront Auburn Program in past decades brought artists to vacant storefronts in the city, providing gallery and exhibition space. A future, more comprehensive business incubator could be considered in existing or new space in Downtown.



A Micro-Restaurant Space at the La Scala in Beaverton, OR. Source: Carleton Hart Architecture.

Zoning and form-based codes

Store size caps

One way to ensure that affordable commercial spaces do not disappear as the Downtown redevelops is to incentivize or even require new mixed-use buildings to include small or micro-retail spaces. For example, The La Scala in Beaverton, Oregon, includes micro-spaces for breweries and restaurants along with a communal eating area. The City's Storefront and Building improvement programs described above could be targeted to assist small or micro-retail spaces.

Height limitations

Limiting building heights along certain corridors such as areas of Main Street can provide a disincentive to redevelopment of historic buildings which may otherwise be demolished under higher or more permissive height regulations. This can provide some displacement prevention for businesses in these buildings.

Streamlined permitting and licensing

Streamlining of licensing can help small businesses, particularly those starting out, avoid delays and complexity getting started. Additionally, streamlined permitting can save developers money, potentially reducing rents for newer commercial spaces. Auburn already offers a downtown Environmental Impact Review which significantly reduces barriers to development in the Downtown. The City could also explore other ways to streamline business permitting and licensing to Downtown businesses.

Design Standards

Updating Design standards to promote more flexibility. (See Redevelopment in Chapter 5|Housing & Redevelopment.)

Displacement Risk Recommendations

DP-H-34 Identify best strategies to reduce commercial displacement risks.

6 | Transportation

Auburn's transportation network consists of vehicle, rail, bicycle, pedestrian and transit facilities. The recommendations provided for the downtown are intended to help achieve the goals and objectives related to transit, multimodal connectivity, and enhanced street design and streetscape.

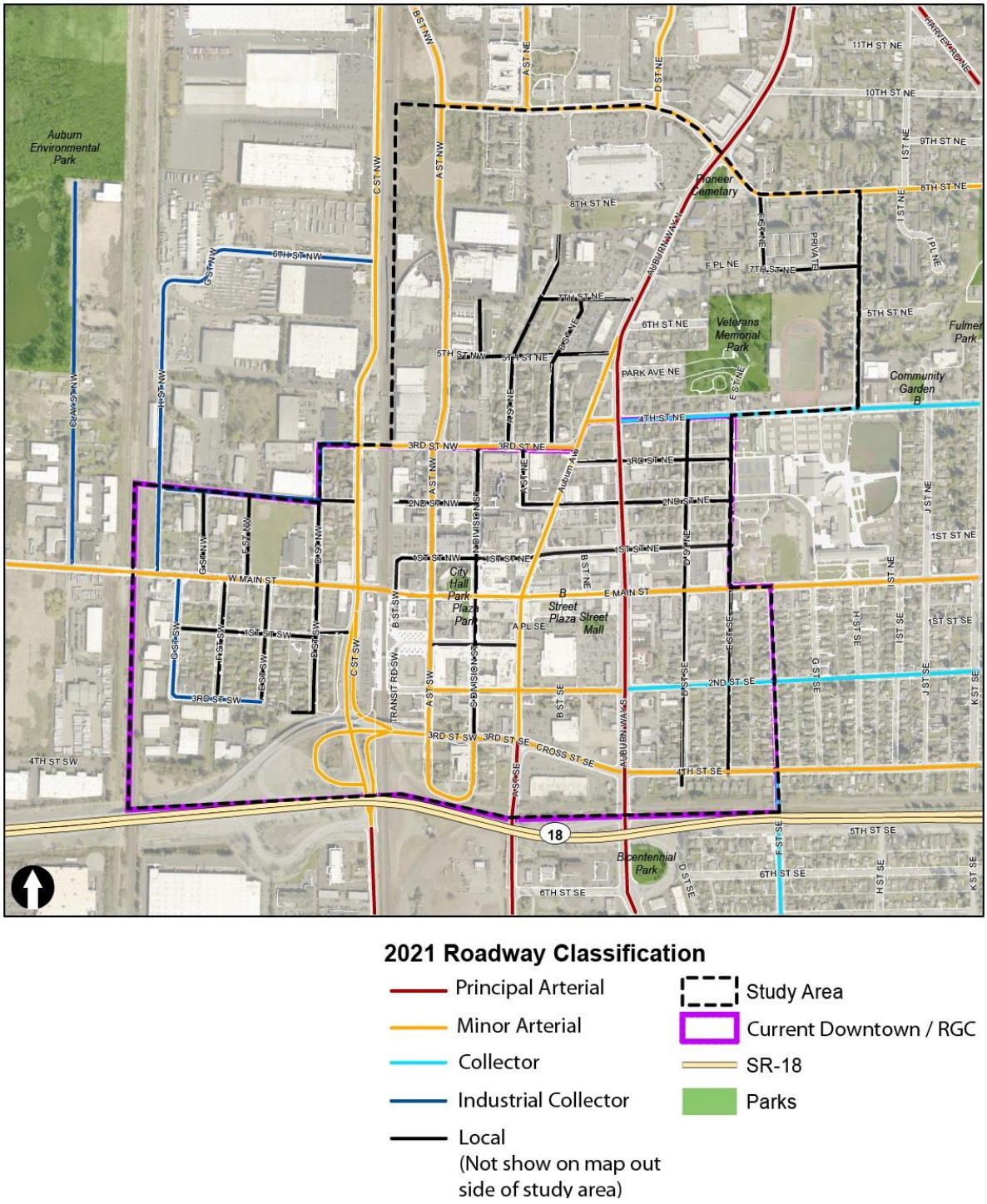
Improving multimodal circulation to and through Downtown Auburn is essential to supporting population and economic growth in the area. This 2024 Downtown Plan and EIS identifies how the City can support vehicle access and circulation, while also expanding bicycle and pedestrian access, and improving access to the city's rail station and frequent service bus routes. This chapter provides existing contents and future improvement opportunities for the following transportation modes:

- Roadway Network and Safety
- Active Transportation
- Transit, Vehicle Circulation, and Parking

Roadway Network and Safety

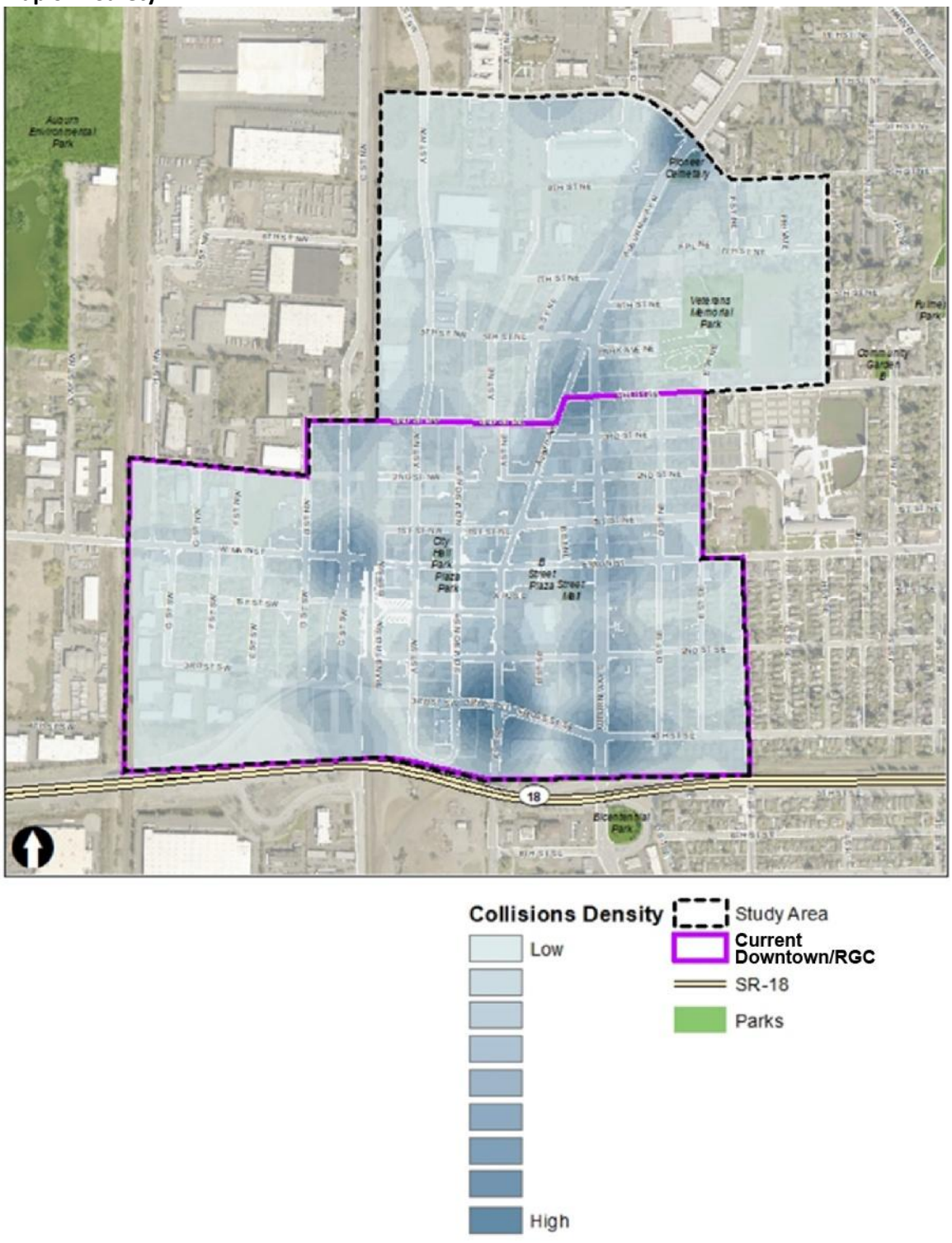
The street system functions as a network. Functional classification is the hierarchy by which streets and highways are defined according to the character of service they provide. The three main classes of streets in Auburn are arterials, collectors, and local streets. 2024 street classifications are shown in Map 6-1. Understanding the existing functional classification helps establish which corridors will provide for the future movement of people and goods, as well as emergency vehicle access. As development is being considered, accommodation for the appropriate transportation corridors is crucial. In the downtown study area, most streets are primarily collector and local roadways, with three arterials running north-south and one east-west connection.

Map 6-1 Roadway Network



Source: City of Auburn, King County, Fehr & Peers and MAKERS

Map 6-2 Safety



Source: City of Auburn, King County, Fehr & Peers and MAKERS

Safety

Safety is a high priority for the City to promote a downtown environment that accommodates multiple transportation modes. Map 6-2 shows the locations in Downtown Auburn with the highest density of collisions, as reported in the City's 2020 Local Road Safety Plan. As shown by the heatmap, many collisions occurred along principal and minor arterial roadways, as well as major intersections. At-grade rail crossing intersections were also evaluated for safety, including several in the downtown study area. There have been recent upgrades to the rail crossings, such as pre-signals that prevent vehicles from stopping on the crossing. The City will continue to make safety improvements in the Downtown Area based on the priorities identified in city-wide safety plans.

Street Grid and Future Circulation Needs

The downtown core generally has a small-block street grid structure, with some larger parcels interrupting the street connections east of A St NE. This grid pattern generally supports strong connectivity in downtown, which facilitates walkability and distributes traffic, benefiting access to major downtown destinations like the Sounder Station and MultiCare. In the North Downtown area, the street grid is more irregular, with large blocks and off-set intersections. New through-block connections, and intersection improvements could improve overall multimodal circulation and safety as downtown continues to redevelop.

The City has some plans for roadway network expansion within the downtown.

Table 6-1 provides an overview of planned transportation projects by 2044. The recently constructed A Street Loop project provides a new key east-west street connection on the southern border of the downtown.

Table 6-1 Planned Transportation Projects for Downtown Auburn (2024-2029 Transportation Improvement Projects (TIP)

Proposed TIP Project	Description
I-7 – Downtown Infrastructure Improvement Project	The purpose of this project is to construct infrastructure improvements in the Downtown Auburn that will support existing development and future re-development activities and to replace infrastructure that is at or near the end of its useful service life. This project will design and construct street and utility improvements in the alley along the north side of the Auburn Ave Theater building, Auburn Ave from the alley to E Main Street, and on E Main Street from Auburn Ave to the B Street Plaza. The project includes replacing the existing traffic signal at the intersection of E Main/Auburn Ave, installing decorative overhead street lighting on E Main Street and the B Street Plaza, replaced sidewalks on E Main Street, sewer and water utility main construction, and other work to improve and enhance the project area.
I-15 - 10th Street NW/A Street NW Traffic Signal	The project will construct a new traffic signal in place of the existing stop-control on the 10th Street NW approach. The project is needed to address a level of service deficiency at the intersection. The project will also evaluate intersection control, channelization, and pedestrian crossing improvements along 10th Street NW to the east of the intersection.
N-5 – 1st Street NE/NW and Division Street Pedestrian Improvements	The project will implement non-motorized improvements at the 1st Street NE/NW/N Division Street intersections in downtown Auburn. Construction is expected to begin in the summer of 2025. The proposed improvements will create a raised intersection to reduce speeds and encourage motorists to yield to pedestrians using the crosswalks; add curb bulbs where they are not currently provided to reduce crossing distances and improve pedestrian visibility; construct new ADA complaint ramps; and both pedestrian level and street lighting improvements.
P-3 - 10th Street NE Non-Motorized Improvements	The project will preserve 10th Street NE between B Street NW and Auburn Way N. The project will also rechannelization the roadway to convert the existing four-lane cross section to a three lanes section incorporating bike lanes and a center two-way left-turn lane. The existing intersection control at the intersection with A Street NE will be revised to remove the east/west stop-control, and the installation of a new north/south crosswalk to the east of the intersection. The new crosswalk is proposed to be enhanced with a median island and a Rectangular Rapid Flashing Beacon (RRFB). The existing signal at D Street NE will require modification to match the new roadway cross section.
R-5 – A Street NW, Phase 2 (W Main Street to 3rd Street NW)	The project will widen A Street NW to create a three-lane roadway section between W Main St and 3rd St NW. This project will improve the connection between the A St NW Extension, (Phase 1) and Auburn Station and Central Business District. The project is approximately 0.2 miles long.

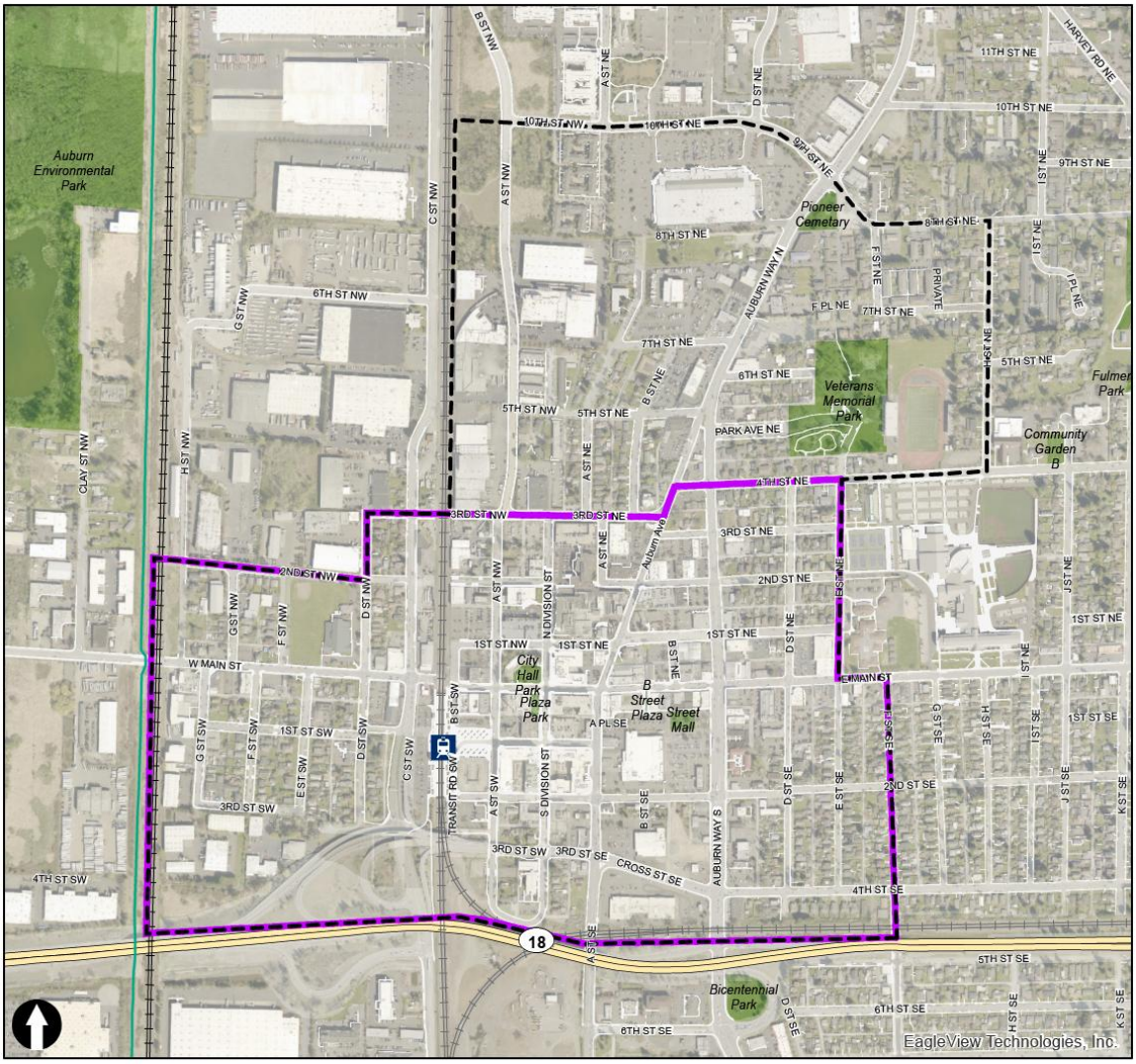
R-16 - 3rd Street NE/Auburn Avenue	The project will construct a northbound left-turn lane and a northbound/southbound crosswalk at the 3rd Street NE/Auburn Avenue intersection and realign the 4th Street NE/Auburn Way N intersection to eliminate the split phase signal operation improving circulation and access. The project will improve traffic operations, safety, and circulation for both vehicles and non-motorized users.

Rail and Freight Circulation

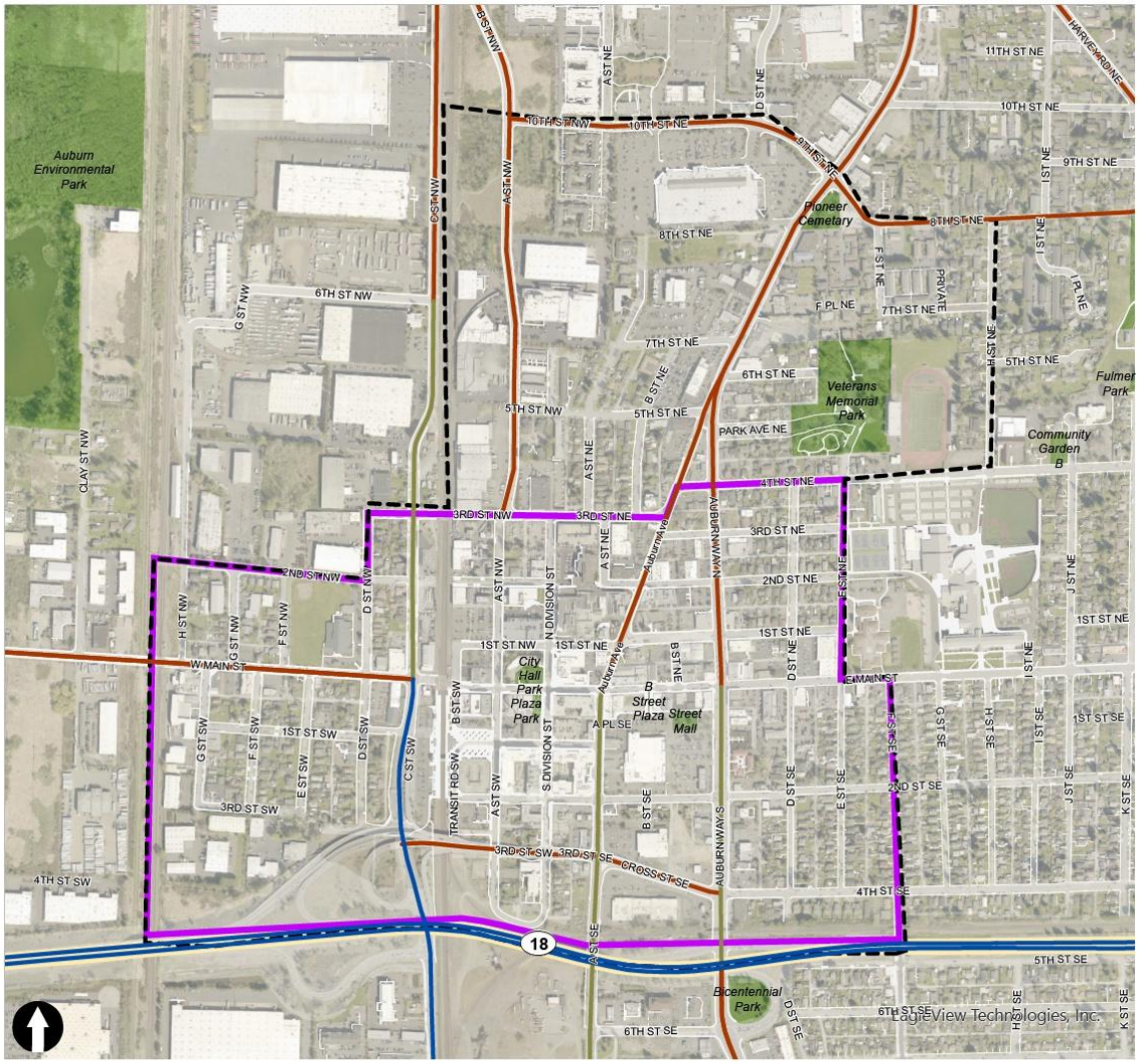
The Union Pacific Railroad (UP) and Burlington Northern Santa Fe Railway (BNSF) have rail lines running through Auburn as indicated in Map 6-3. The UP Railroad runs north-south along the western edge of the study area boundary. BNSF also runs north-south, with 3 rails running through the area. BNSF also has rail lines running east-west along the south edge of the study area along SR-18 (Stampede Pass Line) and operates the rail yard between A Street SE and C Street SW, south of SR-18. This area may develop as a multi-modal rail yard in the future, which could necessitate capacity improvements due to increased truck traffic. While the rail yard is outside the study area, future development could impact traffic flow through downtown. Finally, the Sounder additionally runs through downtown Auburn on the north-south BNSF tracks, with the Auburn Transit station located downtown with one parking garage and a second parking garage under construction with a tentative completion date of 2027.

Downtown Auburn includes some existing industrial uses and commercial operations which require truck access for both delivery and commercial operations. The City of Auburn prohibits large commercial vehicles (16,000 pounds or more) in the downtown traffic control zone (Ordinance 6633) defined as the areas between C St NW and Auburn Way N, and 3RD Ave NE and 3RD Ave SW/Cross St SE. The City allows some exceptions for deliveries to downtown, vehicles originating from a property within the control zone, and public transit, school buses, and emergency vehicles. The City also has dedicated truck routes within downtown. See Map 6-4 for truck route locations.

Map 6-3 Rail Network



Map 6-4 Freight Network



Roadway Network Recommendations

DP-T.1 Implement recommended improvements at the C St NW & 3rd St NW intersection to reduce traffic impacts as downtown redevelopment occurs. (See transportation analysis in EIS for more background.)

DP-T.2 Make improvements to address roadway and intersection safety at key locations highlighted in the City's Local Road Safety Plan and Comprehensive Safety Action Plan (See also Active Transportation in Chapter 6|Transportation).

DP-T.3 Consider strategies to reduce traffic speeds in downtown to improve safety.

DP-T.4 Consider the need for connectivity for both vehicle and non-motorized traffic with new development within the limits allowed. Update design and/or engineering standards to encourage non-motorized connections in mixed-use nodes

DP-T.5 Consider how to facilitate crossing of the BNSF/Sounder rail corridor at W Main St.

DP-T.6 Whenever feasible meet ACC 12.06.030 Complete streets infrastructure and provide complete streets with all new street projects downtown.

Active Transportation

Pedestrian Network

Downtown Auburn offers a mostly complete pedestrian network, in which sidewalks are generally available on both sides of most streets and there are also two multiuse trails in proximity to the study area. Overall, this supports a positive pedestrian environment, as businesses, shops, and single-family homes in the downtown core generally benefit from sidewalks and street trees. However, there are gaps in existing sidewalk infrastructure in the study area and some older sidewalks are five feet wide without buffers provide comfortable walkability. When feasible with redevelopment or major transportation projects, these should be widened to meet the City's current standards. (See also Map 2-7 for a map of sidewalk gaps and pedestrian circulation barriers.)

Pedestrian improvements will be most critical around new nodes of mixed-use development in areas that lack street grid connections and/or sidewalk infrastructure.



L: Vehicle traffic and construction on E Main Street. R: Five-foot sidewalks on Auburn Way N.

Main Street Traffic Analysis

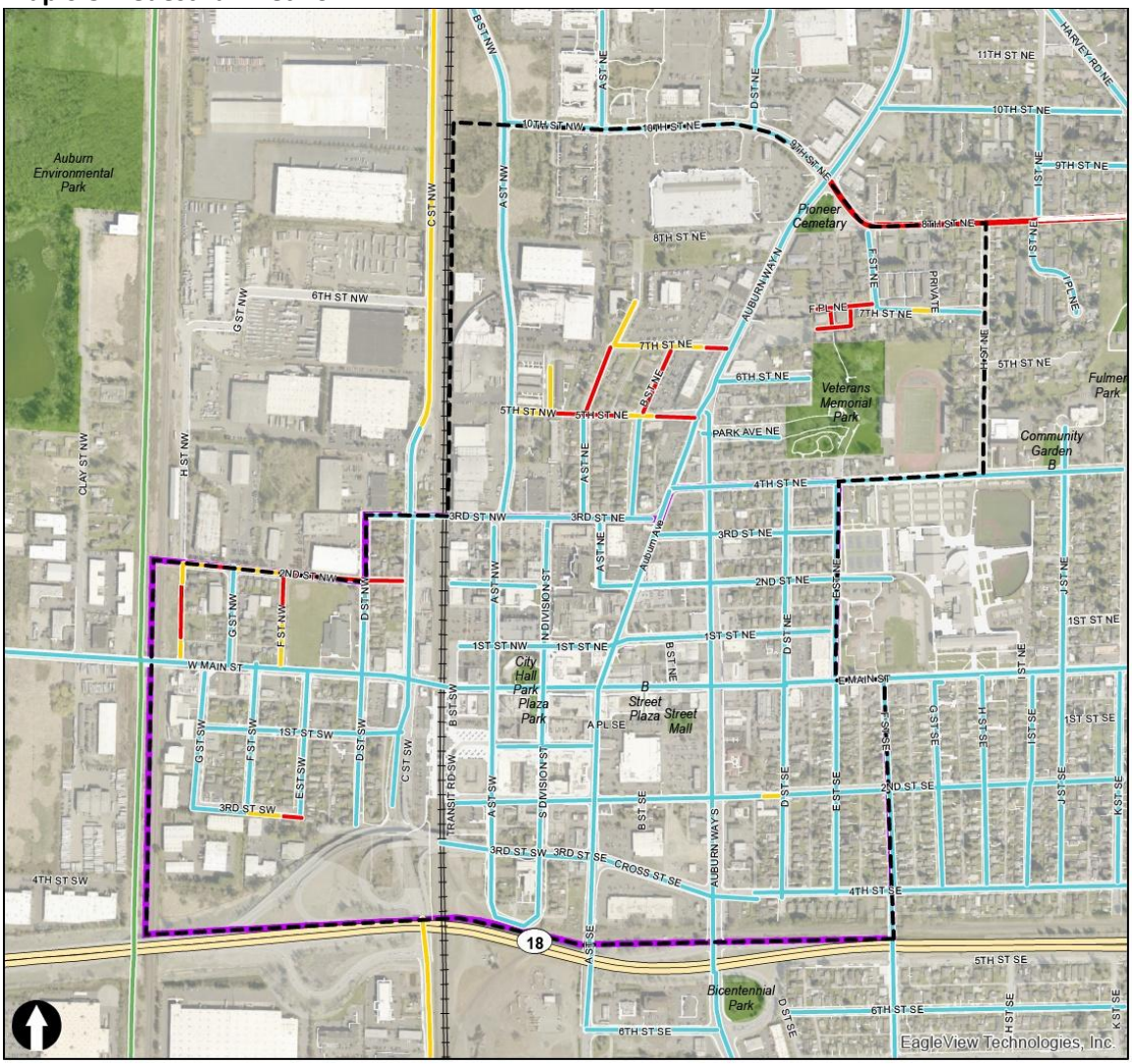
The 2024 Downtown Plan evaluated changing traffic patterns along East Main Street to provide more space for people walking and biking and promote commercial activity along this key business corridor. The City conducted a preliminary traffic analysis of modifying East Main Street from Auburn Ave to Auburn Way. Four options were studied in the analysis:

- Option 1 - Keep the road in its existing two-way traffic configuration.
- Option 2 - Close the road to all vehicle traffic.
- Option 3 - Close the road to eastbound traffic.
- Option 4 - Close the road to westbound traffic.

All scenarios utilized the 2044 Draft-Preferred Land Use Alternative Scenario (2044 Land Use) from the City's 2024 Comprehensive Plan as the background traffic demand model which is also consistent with the methodology used for the EIS. This preliminary traffic analysis shows that, from a traffic operations perspective, Options 1 and 3 are feasible. Implementation of Option 3 would

support the 2024 Auburn Downtown Plan's goals for improving non-motorized circulation and access and promoting more activity in downtown. A more detailed traffic analysis will be required prior to implementation of any changes.

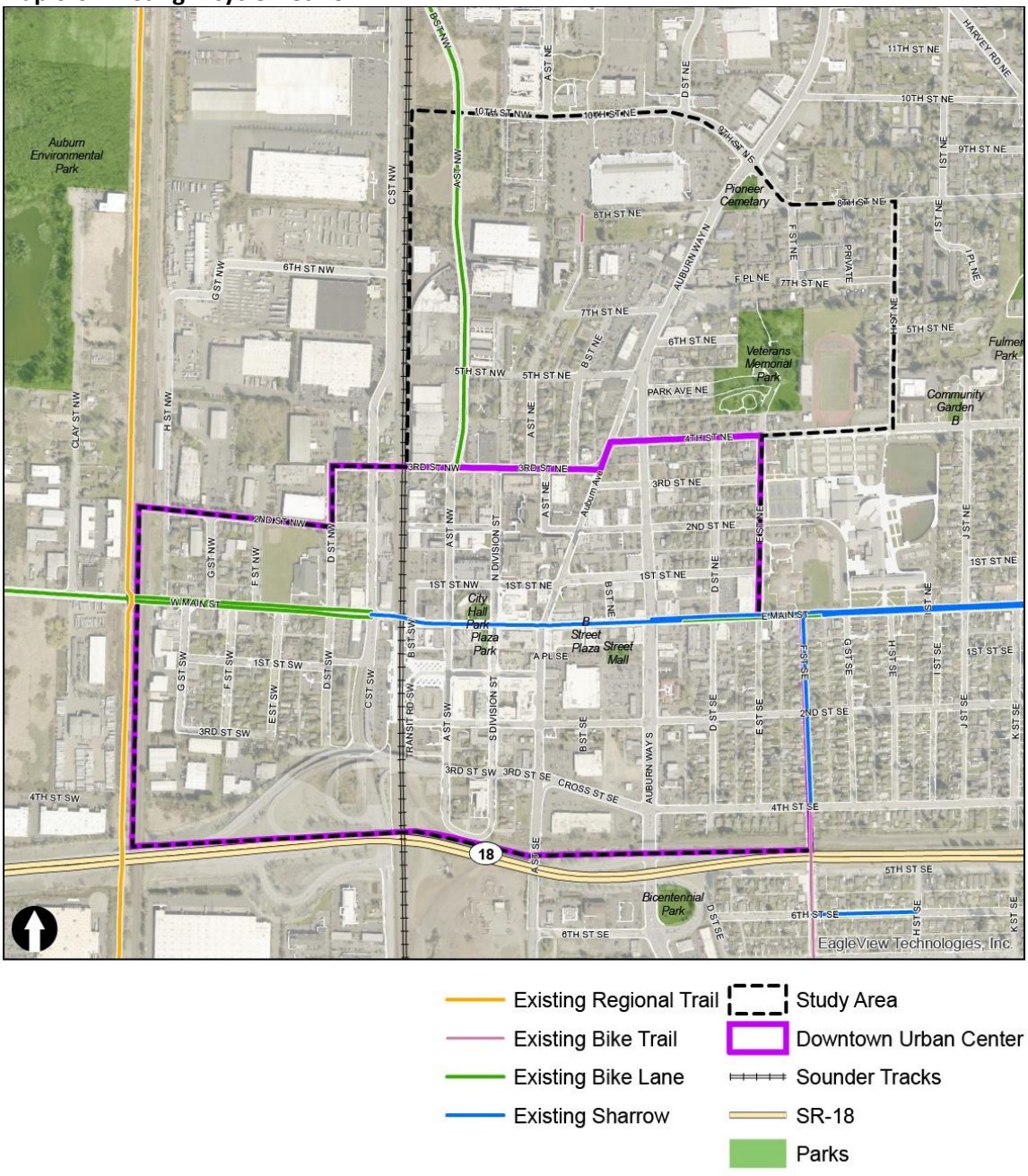
Map 6-5 Pedestrian Network



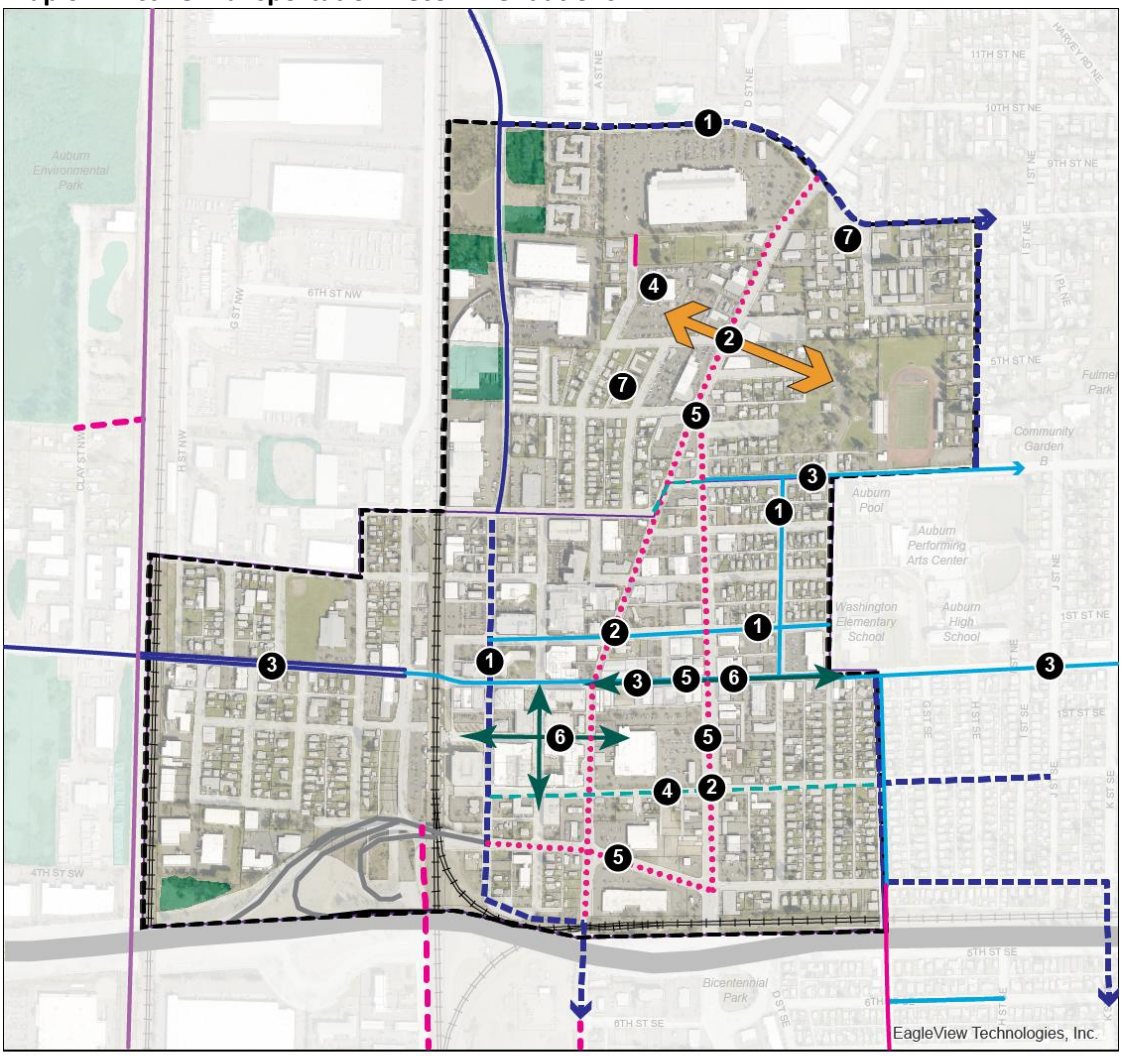
Bicycle Network

Better accommodating people who wish to travel by bike is priority for the City. Current infrastructure benefits from access to regional trails such as the Interurban Trail directly west of downtown. There are also two multiuse trails in proximity to the study area as seen in Map 6-6. Improving existing bike routes through downtown and providing a new low stress connection would be most welcoming for cyclists of all ages and abilities. Map 6-7 highlights the active transportation recommended improvements of the 2024 Auburn Downtown Plan Update.

Map 6-6 Existing Bicycle Network



Map 6-7 Active Transportation Recommendations



Active Transportation Improvements

1. Implementation of planned bike routes and bike facility improvements
2. Identify ped and/or bike crossing improvements to support E-W access. (Specific locations may evolve with redevelopment and/or City plans.)
3. Enhance existing bike facilities
4. New potential bike routes (Coordinate facility type and alignment with redevelopment and City plans.)
5. Streetscape improvement opportunity (priority areas and/or with redevelopment)
6. Corridor activation (strengthen connections, corridor themes, and/or streeteries, etc.)
7. New sidewalk priority areas

- Existing Regional Trail
- Existing Bike Trail
- Existing Bike Lane
- Existing Sharrow
- Planned Bike Route
- Future Trail
- Revised Downtown Area (Proposed)
- Current Downtown/RGC
- Wetlands
- Railroad

2024 Auburn Downtown Plan Recommendations

- Future crossing need (with redevelopment)
- Streetscale improvements (middle/long-term and/or with redevelopment)
- New ped/bike route (middle/long-term and/or with redevelopment)

Active Transportation Improvements Recommendations

DP-T.7 Implement planned bike improvements within downtown in the near-term. Over time, improve facilities in key locations to class II or I bikeways, when feasible, including:

a. Explore strategies to widen and/or buffer existing bike lanes on 3rd St NW/ NE and facilitate crossing of Auburn Way N and Auburn Ave.

b. Provide bike facility improvements with future traffic changes on E Main St.

c. Explore strategies to buffer existing bike lanes on W Main St, west of the C St NW.

DP-T.8 Implement planned ped/bike improvements on priority routes, such as E Main St, that provide access to downtown.

DP-T.9 Implement planned utility, street, and streetscape improvements that support future development in Downtown and enhance ped/bike access, including:

a. Downtown Infrastructure Improvement Project (TIP I-7)

b. 1st Street NE/NW and Division Street Pedestrian Improvements (TIP N-5)

c. 10th Street NE Non-Motorized Improvements (TIP P-3)

d. 3rd Street NE/Auburn Avenue (R-16)

DP-T.10 Seek opportunities to provide new bike routes as redevelopment occurs over time, and expand bike circulation through downtown.

a. Consider new bike facilities on 2nd St SE and in North Downtown, particularly in coordination with redevelopment.

DP-T.11 Identify key pedestrian and bicycle crossing improvements, to improve circulation and access to transit resources, such as the Sounder station, and the KC Metro I Line bus stops.

DP-T.12 Prioritize safety improvements identified in the City's Local Road Safety Plan and Comprehensive Safety Action Plan.

DP-T.13 Facilitate access to Veterans Memorial Park, particularly for new mixed-use nodes in North Downtown.

DP-T.14 Update design and/or engineering standards to encourage non-motorized connections within new mixed-use development areas, particularly in North Downtown.

DP-T.15 Address sidewalk gaps in key areas through redevelopment, to support overall development and improvement.

DP-T.16 Provide complete streets with all new street projects downtown, when feasible.

DP-T.17 Promote streetscape improvements and coordinate with local businesses and redevelopment to support activation, pedestrian comfort, and economic development along key corridors.

DP-T.18 With future ADA transition plan updates, prioritize removing barriers and improving access for people with limited mobility into and around Downtown. Consider programmatic solutions (i.e. shuttle) where physical improvements are not feasible.

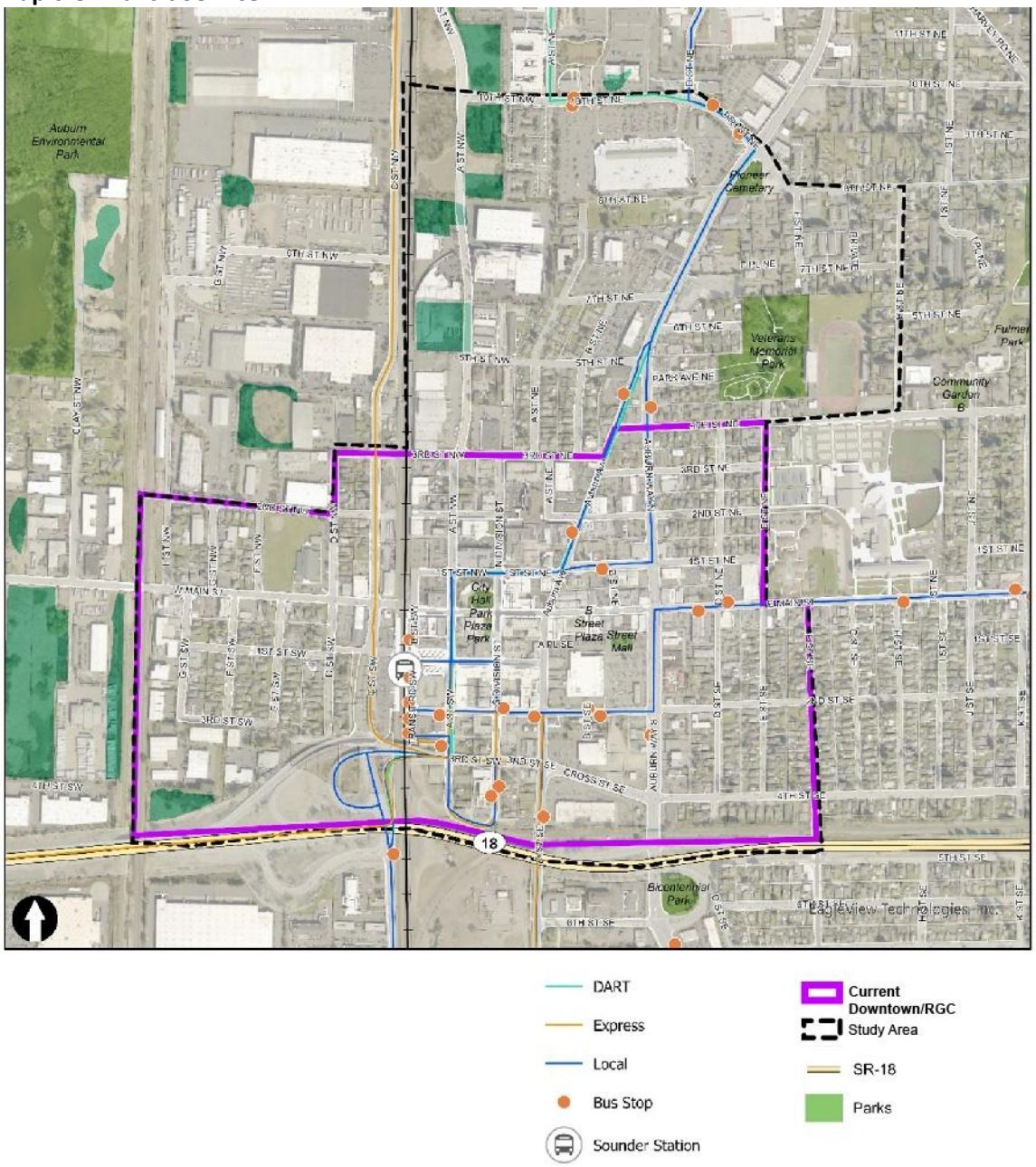
Transit, Vehicle Circulation, and Parking

The City of Auburn does not administer transit service. The City coordinates service with King County Metro Transit, Pierce Transit, Sound Transit, and Muckleshoot Tribal (MIT) transit. Transit in the city operates at local service (30-minute headways in the peak period) and frequent/express service (less than 30-minute headways in the peak period). Service is also offered through DART (Dial-A-Ride Transit) which arranges transit service on demand. As noted above, the City of Auburn has a rail station, which is served by Sound Transit's Sounder train, which runs primarily during peak AM/PM weekday hours. Map 6-8 shows the existing transit network.

RapidRide I Line will upgrade Route 160 (previously Route 180, combined with former Route 169) connecting the cities of Auburn, Kent, and Renton. The service will start at Auburn Station and run along A St SW, 1st St NE, Auburn Ave, and Auburn Way N Serving Kent and ending at Renton Transit Center. When RapidRide I Line launches in Fall 2026:

- Buses will come more often and more reliably for one route service.
- Metro will add service at night and on weekends for one route service.
- Stations will be removed, moved, added and be built to the Rapid Ride standards along the Rapid Ride route.
- All-door boarding and ORCA card readers on buses will mean faster loading and unloading for all passengers if implemented by Metro on the Rapid Ride route.
- Improved sidewalks and street crossings will make it easier and more comfortable to get to/from bus stations along the Rapid Ride Route.

Map 6-8 Transit Service



Access to Transit Stations and Stops

The Sounder Station is a key destination within Downtown Auburn. Parking lots around the station support commuters arriving by car. Recent sidewalk improvements and the public plaza at the station also support people walking to and from the station. Increased uses of the station plaza (special events, seasonal performances, etc.) could help activate the area and foster a stronger connection between the station and downtown.

Access to bus stops within downtown could be improved by coordinating with the transit agency to increase lighting and expanding space to provide more comfort for people waiting for the bus.

Within the study area, the top three bus stops, in terms of boardings and alightings, are at the Auburn Sounder Station for routes 184, 160, and 181 (Auburn Sounder Station & 1st St SW[13]*). The City will continue to explore opportunities to increase access to transit by making improvements identified in City-wide plans, improving pedestrian facilities with redevelopment and public investments, and will coordinate with KC Metro to identify strategies that promote safety and comfort around bus stops.



Auburn Sounder Station

[13] *Source: Fehr & Peers, Spring 2022*

Vehicle Circulation and Traffic Operations

While the City aspires to provide a connected, multimodal system that provides residents, employees, and visitors with robust options, private automobiles will continue to be an important mode that serves many trips. As such, this 2024 Downtown Plan seeks to maintain a basic level of vehicle mobility, even as Auburn grows.

As of the 2021 comprehensive plan, the City uses a single-mode level-of-service (LOS) system to measure conditions for vehicular travel. Corridor segments within Downtown Auburn may operate at LOS E. All other arterial and collector corridors in the city must operate at LOS D or better, unless otherwise indicated. The City measures vehicle mobility during the weekday PM peak hour, the time when Auburn's streets are busiest, unless there are unique conditions present.

The EIS analysis found that potential traffic impacts from land use changes proposed in the 2024 Downtown Plan could be mitigated by making improvements in key locations. The City will monitor change and consider future improvements as redevelopment occurs. See EIS for more details.

See the transportation analysis in the EIS for more details.

Parking

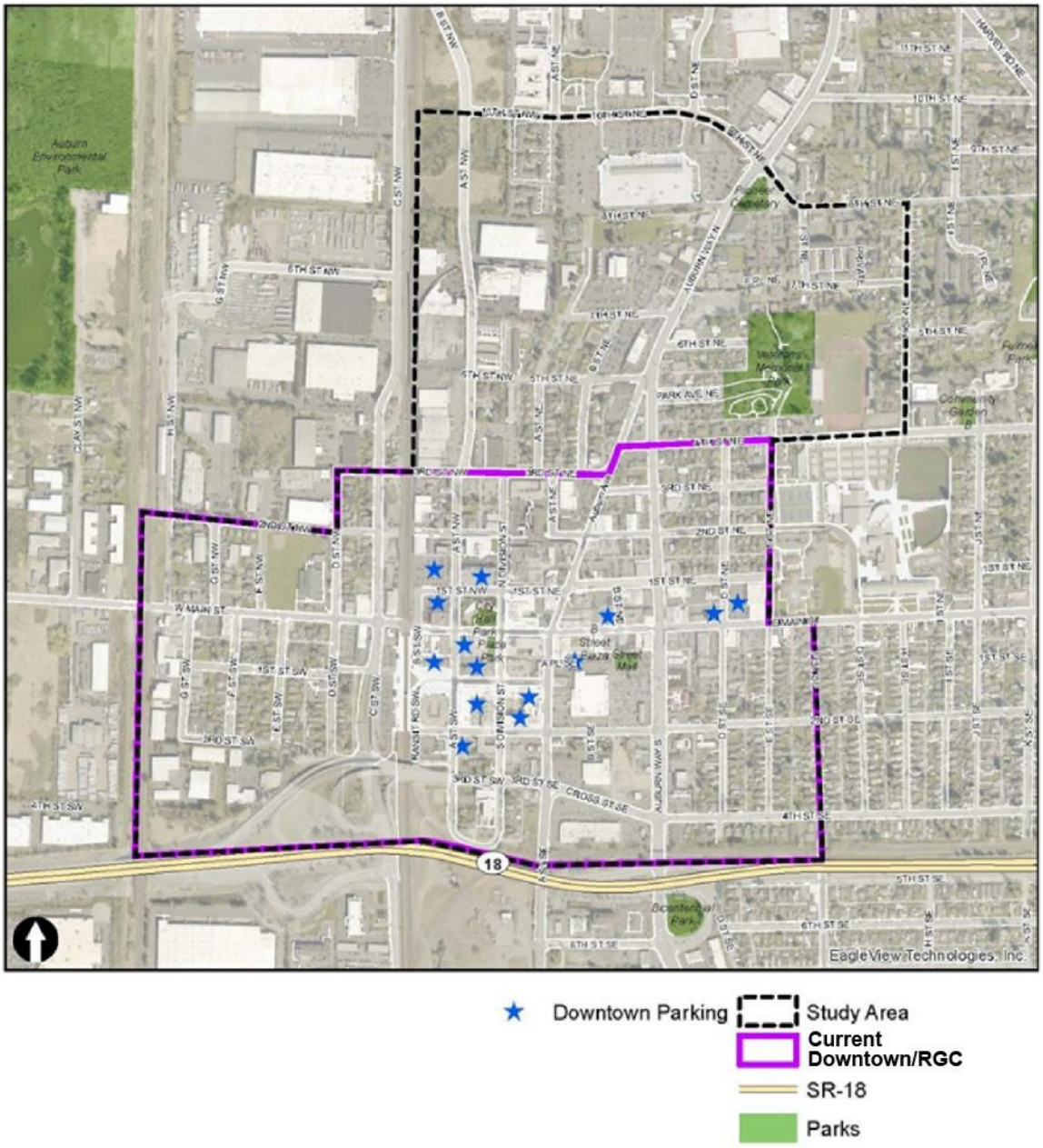
According to the Comprehensive Downtown Parking Management Plan (CDPMP), adopted January 2014, there were a total of 4,879 parking spaces in the Downtown Urban Center (DUC) as of December 2011. This includes on-street public parking, off-street public parking, and off-street private parking. Map 6-9 Parking shows the locations of parking lots downtown. Other parking is included on-street with time limits.

Sound Transit is also planning a new parking structure within Downtown to provide additional parking capacity for the Sounder. The City will continue to monitor and evaluate parking needs as conditions evolve.



Auburn Station Park and Ride Garage

Map 6-9 Parking



New Mobility and Future Needs

As Downtown grows, beyond accommodating traditional modes like walking, biking, and transit, the public right of way will also need to accommodate the needs of emerging roadway uses like drop offs and pickups associated with ride hailing companies, electric vehicle charging in off-street parking areas, as well as increased demands for freight loading associated with online shopping and associated deliveries. To ensure Downtown is ready to accommodate these new roadway users, the 2024 Downtown Plan recommends that the City adopt practices recommended in national guidance, such as the Institute of Transportation Engineers' Curbside Management Practitioner's Guide[14] and by the National Association of City Transportation Officials' Urban Street Design Guide[15].



Image showing diverse use of curb space in a downtown area.

[14] Institute of Transportation Engineers. Curbside Management PR actioner's Guide. 2017. https://s23705.pcdn.co/wp-content/uploads/2019/03/ITE-Kerbside-Curbside-Management-Guide.pdf

[15] National Association of City Transportation Officials. Urban Street Design Guide. Accessed April, 2023. https://nacto.org/publication/urban-street-design-guide/

Transit, Vehicle Circulation and Parking Recommendations

DP-T.19 Coordinate with KC Metro (and other partners) to identify bus stop improvement projects, including lighting, CPTED principles to enhance safety and comfort for people waiting for buses.

DP-T.20 Enhance E-W connection between Sounder station and plaza and Downtown Core with redevelopment, through multimodal access and streetscape improvements, art themes, etc. (See also Chapter 4|Land Use & Urban Design)

DP-T.21 Review and identify curb space management needs in downtown and consider the following:

a. Incorporate a survey of downtown curb space management needs (ride-share drop off, food pick-up, etc.) into upcoming parking study (or other near-term study).

b. Adopt practices recommended in national guidance (ICE, NACTO) such as a prioritization framework for downtown that balances multiple needs on downtown streets.

c. Establish a parking management strategy that addresses supply of parking, on-street parking, and mitigating the effects of parking.

DP-T.22 Promote transition to electric vehicles within Auburn by and consider the following:

a. Review guidance on location, type, and amount of EV charging infrastructure (i.e. charging hubs, public and publicly accessible lots, private parking areas)

b. Review existing EV charging infrastructure with all new development projects to ensure adequate infrastructure in place (particularly near multiunit buildings.)

c. Review retrofits for new charging in existing buildings and consider opportunities for streamlining.

7 | Parks & Public Spaces

The core of Downtown Auburn includes several public plazas that provide opportunities for gatherings, festivals, recreation, public art, and performances. The 2024 Downtown Plan seeks to build on this strong foundation by promoting activity and use of existing spaces and increasing access to green open spaces.

Green Space

The 2024 Downtown Plan promotes access to green space in downtown by recommending the City invest in a new public park, promote open space with redevelopment, and improve access to existing green spaces, specifically Veterans Memorial Park.

New Green Spaces

Downtown Auburn lacks green open space, and siting a new park/plaza Downtown has been a goal of the City Parks Recreation, Open Space, & TrailsPlan. The City's acquisition of property near the Auburn Theater site, close to the Postmark Center for the Arts, creates an opportunity to build on this community asset hub while offering green space, shade, and places for resting, small gatherings, and play.

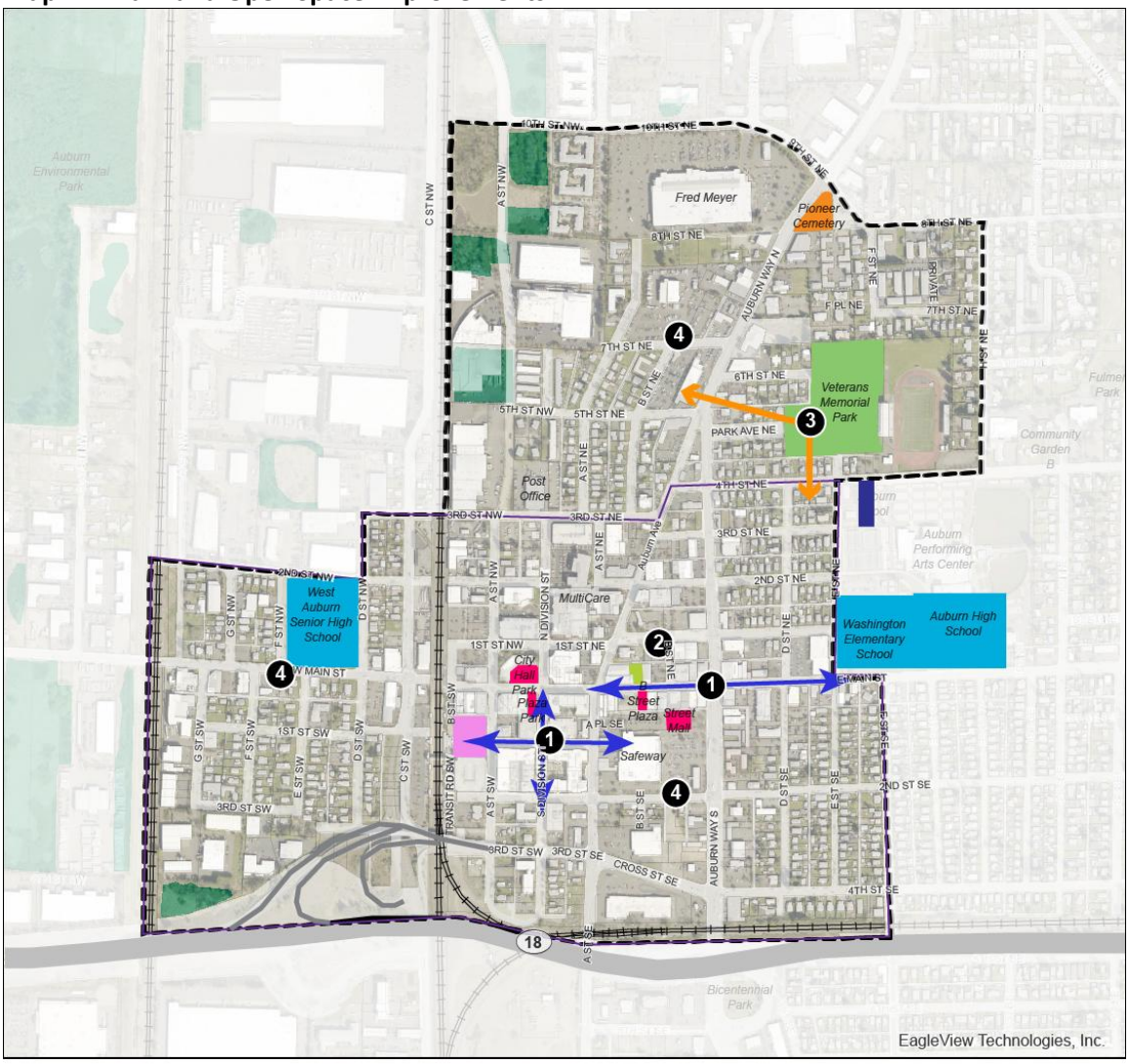
Beyond this public investment, 2024 Downtown Plan also recommends promoting privately owned public spaces with redevelopment, particularly on larger sites. Open spaces connected to streets should incorporate trees for shade, and provide amenities that benefit both residents and people visiting downtown, such as creative play features, or small dog parks.





Trees providing shade in urban plazas and privately owned public spaces.

Map 7-1 Park and Open Space Improvements



Parks and Public Space Improvements

1. Corridor activation (strengthen connections, corridor themes, and/or streeteries, etc.)
2. Locate a new public park downtown near Postmark Center for the Arts.
3. Create safer connections to Veterans Memorial Park
4. Promote green open space, GSI, and/or tree canopy cover in mixed use development nodes. (Locations shown are general, to be coordinated with redevelopment.)

- Plazas
- ST Plaza
- Parks
- Pool (Indoor)
- Cemetery
- School Facilities
- Study Area
- Current Downtown/ RGC
- Wetlands
- Railroad
- Proposed Park

Green Infrastructure and Shade

In addition to new parks and pocket plazas, redevelopment can provide opportunities for functional open space, such as green stormwater infrastructure, that help manage runoff while also providing helpful co-benefits for reducing urban heat impacts, and providing shade. Maximizing benefits public benefits from GSI features should be considered with future redevelopment, particularly on large sites where there could be significant benefits.

Increasing tree canopy where there are opportunities is another important goal for Auburn, particularly given the extent of impervious surface coverage in the area surrounding downtown, and the trends toward more urban heat island impacts. The 2024 Auburn Downtown Plan recommends promoting street trees (including on-site trees along the street) and canopy cover wherever feasible, to reduce temperatures and increase resilience in the city. Redevelopment in North Downtown may provide particular opportunities for increasing tree canopy cover and shade.

Access to Existing Green Space

Expanding the northern border of downtown provides an opportunity to build stronger connections between downtown and Veterans Memorial Park, and significant open space asset in the city. While the park is relatively accessible from residential areas east of downtown, it is a longer distance from the core area, and requires crossing larger arterials. Providing crossings of Auburn Ave from North Downtown will be critical to ensuring future residents have comfortable access to the park's green space and recreation benefits.



Bioswale and trees provide amenity to adjacent sidewalk and businesses.

Green Space Recommendations

DP-P.1 Construct a new public plaza connecting Postmark to Main Street and the B-street plaza.

DP-P.2 Encourage the inclusion of publicly-accessible green open space with large redevelopment.

DP-P.3 Increase tree canopy where feasible on downtown streets and public spaces, to increase opportunities for shade and reduce urban temperatures.

a. Consider green street treatments around larger sites and redevelopment areas that utilize both street trees and GSI to manage stormwater, reduce urban temperatures, help slow traffic, and help connect people living in urban environments to natural systems.

DP-P.4 Improve access to Veterans Memorial Park from the downtown core and North Downtown by providing stronger non-motorized connections.



Streetscape and urban plaza elements can encourage play and exploration for all ages.

Public Space Opportunities

Activation

Activating existing public spaces in downtown is a key priority for the near-term to encourage use, increase eyes on the street to promote safety and security, and support overall economic benefits by increasing the vibrancy of downtown. The 2024 Downtown Plan identified a number of strategies that could help increase activity and use of the city's existing spaces.

- **Recurring Events**. Supporting recurring events located downtown, such as monthly art walks, summer street fairs, craft markets, and cultural celebrations, can help increase activity, and attract new visitors to the city center.
- **Lighting Improvements.** Conducting a lighting audit and identifying areas for more lights were need to promote security and comfort at night was noted as a key need by several local business owners.
- **E Main St Activation.** E Main St has a distinct character within downtown, and is a hub of local shops and businesses. Promoting more activity in this area can help businesses attract new customers, and encourage more people to spend time downtown.
- **Arts Activation.** Arts events can help activate underutilized public spaces. This strategy could also be utilized if there are vacant commercial spaces adjacent to plazas, or along key corridors, as temporary gallery spaces and/or performances can benefit property owners by helping to market existing spaces. Property-owners should cover cost of this type of installation.



Cultural Connections

Public spaces within a downtown area can also play an important role in communicating the history and culture of a place through art, design, and elements included in the space. The 2024 Auburn Downtown Plan considered how the City could continue to infuse downtown with a sense of place, even as redevelopment changes the urban fabric of the area.

- **Cultural Themes.** Working with local community members to identify important themes and build on those through downtown Auburn is one way to strengthen community connections.
- **Cultural Themes.** Auburn is a diverse community, and public spaces within downtown reflect and celebrate that diversity through design elements, art features, and events.

Public Space Recommendations

DP-P.5 Promote recurring events downtown to increase activity and attract new people to the area.

DP-P.6 Assess lighting needs and make improvements to increase comfort and security at night.

DP-P.7 Promote E Main St as a center for special events and activities, and help attract more customers to local businesses. Work with local business district to identify additional activation strategies.

DP-P.8 Consider how temporary arts installations and/or events can help activate public and private spaces.

DP-P.9 Continue to use public space elements and art to strengthen the sense of place within downtown and honor the diverse cultural community of Auburn.



Recently renovated Postmark Center for the Arts is a public space asset that will help activate downtown. Photo courtesy of Will Austin Photography.

8 | Utilities

To support growth and evolution of Downtown Auburn, future planning, coordination, and investments will be needed to ensure City utility services meet future demands and align with current regulations and guidance.

Water and Sanitary Sewer Service

The Water System Plan developed for the 2024 Comprehensive Plan Update considered land use changes consistent with the 2024 Downtown Plan. Though the downtown area generally has adequate water service and can meet future demands, water system improvements were identified in the Water System Plan to address specific deficiencies over the planning period. The City will continue to implement utility improvements to address identified deficiencies over the planning period that are needed to support future redevelopment in downtown.

- The Water System Plan identified areas where there is some limitation in water service currently and includes a prioritized list of improvements to address those limitations over the 20-year planning period.
- The Comprehensive Sewer Plan identified areas with key conveyance deficiencies and included those areas in a list of capital improvements over the 20-year planning period.

In addition to investments identified in the plans noted above, the City could also support future redevelopment by identifying grants for public investments to upgrade sewer and wastewater infrastructure where redevelopment may require cost prohibitive upgrades. The City could also explore new funding opportunities, such as Tax Increment Financing to support infrastructure improvements. See Programs, Funding, and Incentives in Chapter 5| Housing & Redevelopment for more details.

Stormwater Management

Green Stormwater Infrastructure (GSI), such as rain gardens, bioretention swales, provides multiple benefits to Downtown Auburn by treating runoff, improving water quality, reducing the urban heat island effect, and increasing trees and landscape areas. The City will encourage the implementation of GSI as redevelopment occurs downtown, and will consider flexibility with private landscape requirements.

Utility Recommendations

DP-U.1 Implement planned projects identified in the City's Comprehensive Plan to continue to improve water and sewer capacity in Downtown.

DP-U.2 Use strategic public infrastructure to stimulate private investment in economic development and redevelopment activities in the planning area such as TIF, LID, latecomers agreements, and system oversizing. City-owned and operated utilities should continue to pursue federal, state, and private grants to finance infrastructure.



Examples of green stormwater infrastructure integrated with private development (at left) and incorporated into a streetscape (at right).

9 | Implementation

This element provides an overview of implementation steps and provides a high-level framework to guide the City's actions over the duration of the plan. This is intended to be a general framework, which can evolve and change as the city evolves.

The following chart provides a high-level overview of recommended actions, and an estimate of the timing when action may occur, as well as key roles and potential resources or funding uses for implementation. These are estimates only – changes to implementation timing, roles, and funding may evolve as opportunities arise and as resources allow.

Implementation Chart Key

Timing

- Short (S) – 1-5 years
- Medium (M) – 5-10 years
- Long (L) – 10-20 years
- Ongoing (S-L) – a continuous action over time
- Opportunistic (O) – as funding or opportunity arises

Role (Responsible Party)

- City Council (CC)
- Community Development (Planning, Community Services) (CD)
- Economic Development (ED)
- Parks, Art, & Recreation (PCR)
- Public Works (PW)
- King County Metro (KCM)
- Sound Transit (ST)
- Utility providers (Utilities)

Potential Resources /Funding

- Public – staff resources, public funds, public grant funds
- Private – required with redevelopment, private partner involvement

Table 9-1 Implementation Summary Table

Action	Timing	Role	Potential Resources/ Funding
LAND USE RECOMMENDATIONS			
DP-LU.1 Provide more opportunities for growth within Downtown Auburn and align with regional growth strategies by coordinating with PSRC to expand the Regional Growth Center boundary.	S	CD	Public
DP-LU.2 Adopt proposed zoning changes described in 2024 Downtown Plan (See Zoning Recommendations for more details.)	S	CD	Public
DP-LU.3 Review and update design standards to ensure regulations promote compatibility between adjacent land uses. (See Zoning Recommendations for more details.)	S	CD	Public
DP-LU.4 Where feasible, consider landscape buffers between new housing and freeways, and utilize this space for green infrastructure (GSI, urban heat mitigation, etc.)	Ongoing	CD	Public/Private
DP-LU.5 Update DUC design standards with consideration for areas in North Downtown.	S	CD, PW	Public
DP-LU.6 Update Pedestrian Streets designations. (See Urban Form Recommendations for more details.)	S	CD, PW	Public
DP-LU.7 Require redevelopment to provide strong connections for people walking, biking, and using transit through the construction of new, complete streets, street improvements, and/or new through block connections.	Ongoing	CD, PW	Private
DP-LU.8 Support decarbonization of existing buildings and new development to align with Auburn's climate change goals. (See Green Building and Resilience Recommendations for more details.)	Ongoing	CD	Public/Private
DP-LU.9 Promote efficient water use in buildings and landscapes within downtown. (See Green Building and Resilience Recommendations for more details.)	Ongoing	CD, PW	Private
DP-LU.10 Require water-efficient landscape with new buildings.	Ongoing	CD, PW	Private

DP-LU.11 Reduce the urban heat island effect by: a. Expanding tree canopy cover outside of right-of-way and increasing green space within Downtown. b. Update development standards to promote passive cooling, reflective and/or cooling building materials, and other design strategies.	Ongoing	CD, PW	Private
DP-LU.12 Provide a resilience hub in Downtown, that provide access to cool spaces and air filtration during periods of extreme heat and/or wildfire smoke.	M	CD, PAR	Public/Private
DP-LU.13 Support the transition to electric vehicles within downtown. (See Green Building and Resilience Recommendations for more details.)	Ongoing	CD/PW	Public/Private
HOUSING AND REDEVELOPMENT RECOMMENDATIONS			
DP-H-1 Update the Downtown Urban Center Zone to encourage more affordable housing (See Housing Recommendations for more details.)	S	CD	Public
DP-H-2 Revise citywide residential zoning through the comprehensive plan process to incorporate middle housing types and apply appropriate zones in downtown.	S	CD	Public
DP-H-3 Implement HAPI recommendations generally, including updated definitions, zone intent, permitted uses tables, dimensional standards, parking requirements, and internal conversions.	S	CD	Public
DP-H-4 Ensure zoning updates allow apartments in all downtown residential zones.	S	CD	Public
DP-H-5 Update the City's MFTE program to encourage greater flexibility and use. (See Housing Recommendations for more details.)	S	CD	Public
DP-H-6 Continue using the Affordable and Supportive Housing Sales Tax Credit Fund for acquisition, rehabilitation, and construction of affordable housing; operations and maintenance costs of new affordable or supportive housing units; and rental assistance provisions to tenants.	S	CD	Public
DP-H-7 Continue to promote development sites and seek partners.	Ongoing	CD	Public

DP-H-8 In the medium-term the City should define a plan for redevelopment. Begin to seek grant funds, and/or nonprofit or private development partners in order to implement the defined and desired development. If one or more stand-alone arts venues are not being pursued, then other options should be considered and implemented to avoid long-term vacancy of the sites.	S	CD	Public/Private
DP-H-9 Market the benefits of the Planned Action SEIS such as reduced SEPA review and risk for developers.	S	CD, ED	Public
DP-H-10 Highlight importance of Arts to Downtown Auburn by: a. Continuing to support local public art program. b. Fostering Arts Commission to generate local interest and opportunities for the arts. c. Explore potential for forming an Arts District in downtown by creating a local district, or pursuing state programs. d. Build on recent investments around the Postmark Center for the Arts. e. Pursue mixed-use project that combines affordable housing and arts and/or performance space on City-owned properties in this area. f. Leverage Main Street traffic revisions to accommodate more active art events in this space. g. Work with local partners and businesses to support arts-themed events (Sound Transit, MultiCare, etc.)	Ongoing	CD, PAR	Public/Private
DP-H-11 Encourage new types of businesses in Downtown that provide new activities, including new restaurants, arts-related spaces, etc.	Ongoing	CD, ED	Public/Private
DP-H-12 Continue to monitor redevelopment and permit activity and work with developers to ensure the 2024 Auburn Downtown Plan's goals are being met by new development in the area.	Ongoing	CD, ED	Public
DP-H-13 Actively facilitate project in key locations. (See Promoting Redevelopment Recommendations for more details.)	S-M	CD, ED, CC	Public
DP-H-14 Develop a plan to prioritize action on other City-owned sites. (See Promoting Redevelopment Recommendations for more details.)	S	CD, ED, PAR, PW	Public
DP-H-15 Promote Medical-Wellness hub around MultiCare. (See Promoting Redevelopment Recommendations for more details.)	M	CD, ED	Public/Private
DP-H-16 Update design standards to promote more flexibility, particularly for ground floor commercial spaces, to promote a wider range of businesses. (See Promoting Redevelopment Recommendations for more details.)	S	CD, ED, PW	Public
DP-H-17 Consider using TIF as a funding mechanism in the Downtown for specific projects.	S-M	CD, CC	Public

DP-H-18 Maintain and expand existing City programs to support local businesses and address storefront vacancies. (See Programs, Funding, and Incentive Recommendations for more details.)	S-M	CD, ED	Public
DP-H-19 Consider participating in state programs that align with the key goals of specific areas within downtown.	S-M	CD	Public
DP-H-20 Apply for Downtown Auburn to become a designated creative district through ArtsWA. (See Programs, Funding, and Incentive Recommendations for more details.)	S-M	CD, PAR	Public
DP-H-21 Coordinate with the Downtown Auburn Cooperative, and other organizations, and seek to develop partnerships to improve security and promote new economic opportunities.	Ongoing	PAR	Public
DP-H-22 Continue to seek coordination and partnership opportunities with other major employers, institutions, and Tribes located in and around downtown Auburn.	Ongoing	CD, ED	Public/Private
DP-H-23 Identify best strategies to reduce commercial displacement risks.	S-M	CD	Public
TRANSPORTATION RECOMMENDATIONS			
DP-T.1 Implement recommended improvements at the C St NW & 3rd St NW intersection identified in the FEIS to reduce traffic impacts as downtown redevelopment occurs.	O	PW	Public
DP-T.2 Make improvements address roadway and intersection safety at key locations highlighted in the City's Local Road Safety Plan and Comprehensive Safety Action Plan.	O	PW	Public
DP-T.3 Consider strategies to reduce traffic speeds in downtown to improve safety.	O	PW	Public
DP-T.4 Consider the need for connectivity for both vehicle and non-motorized traffic with new development within the limits allowed. Update design and/or engineering standards to encourage non-motorized connections in mixed-use nodes.	O	PW	Public
DP-T.5 Consider how to facilitate crossing of the BNSF/Sounder rail corridor at W Main St.	M-L	PW	Public
DP-T.6 Whenever feasible meet ACC 12.06.030 Complete streets infrastructure and provide complete streets with all new street projects downtown.	Ongoing	PW	Public
DP-T.7 Implement planned bike improvements within downtown in the near-term. Over time, improve facilities in key locations to class II or I bikeways, when feasible. (See Active Transportation Improvements Recommendations for more details.)	S-M	PW	Public/Private

DP-T.8 Implement planned ped/bike improvements on priority routes, such as E Main St, that provide access to downtown.	O	PW	Public/Private
DP-T.9 Implement planned utility, street, and streetscape improvements that support future development in Downtown and enhance ped/bike access. (See Active Transportation Improvements Recommendations for more details.)	S-M	PW	Public
DP-T.10 Seek opportunities to provide new bike routes as redevelopment occurs over time, and expand bike circulation through downtown. (See Active Transportation Improvements Recommendations for more details.)	O and Ongoing	PW	Public/Private
DP-T.11 Identify key pedestrian and bicycle crossing improvements, to improve circulation and access to transit resources, such as the Sounder station, and the KC Metro I Line bus stops.	O and Ongoing	PW	Public/Private
DP-T.12 Prioritize safety improvements identified in the City's Local Road Safety Plan and Comprehensive Safety Action Plan.	Ongoing	PW	Public
DP-T.13 Facilitate access to Veterans Memorial Park, particularly for new mixed-use nodes in North Downtown.	O and Ongoing	PW. PAR	Public/Private
DP-T.14 Update design and/or engineering standards to encourage non-motorized connections within new mixed-use development areas, particularly in North Downtown.	S	PW, CD	Public/Private
DP-T.15 Address sidewalk gaps in key areas through redevelopment, to support overall development and improvement.**Error! Bookmark not defined.**	O and Ongoing	PW, CD	Public/Private
DP-T.16 Provide complete streets with all new street projects downtown, when feasible.	Ongoing	PW, CD	Public/Private
DP-T.17 Promote streetscape improvements and coordinate with local businesses and redevelopment to support activation, pedestrian comfort, and economic development along key corridors.	O	PW, CD, PAR	Public/Private
DP-T.18 With future ADA transition plan updates, prioritize removing barriers and improving access for people with limited mobility into and around Downtown. Consider programmatic solutions (i.e. shuttle) where physical improvements are not feasible.	M	PW	Public/Private
DP-T.19 Coordinate with KC Metro (and other partners) to identify bus stop improvement projects, including lighting, CPTED principles to enhance safety and comfort for people waiting for buses.	S-M	PW. CD	Public

DP-T.20 Enhance E-W connection between Sounder station and plaza and Downtown Core with redevelopment, through multimodal access and streetscape improvements, art themes, etc.	Ongoing	CD, PAR, PW	Public/Private
DP-T.21 Review and identify curb space management needs in downtown. (See Transit, Vehicle Circulation and Parking Recommendations for more details.)	O	CD, PW	Public
DP-T.22 Promote transition to electric vehicles within Auburn. (See Transit, Vehicle Circulation and Parking Recommendations for more details.)	O	CD, PW	Public/Private
PARKS AND OPEN SPACE RECOMMENDATIONS			
DP-P.1 Construct a new public plaza connecting Postmark to Main Street and the B-street plaza.	M	PAR, CD	Public
DP-P.2 Encourage the inclusion of publicly-accessible green open space with large redevelopment.	O	CD, PAR	Public/Private
DP-P.3 Increase tree canopy where feasible on downtown streets and public spaces, to increase opportunities for shade and reduce urban temperatures. (See Green Space Recommendations for more details.)	O	CD, PAR, PW	Public/Private
DP-P.4 Improve access to Veterans Memorial Park from the downtown core and North Downtown by providing stronger non-motorized connections.	O	CD, PAR, PW	Public/Private
DP-P.5 Promote recurring events downtown to increase activity and attract new people to the area.	Ongoing	CD, ED, PAR	Public/Private
DP-P.6 Assess lighting needs and make improvements to increase comfort and security at night.	S	CD, PW, PAR	Public
DP-P.7 Promote E Main St as a center for special events and activities, and help attract more customers to local businesses. Work with local business district to identify additional activation strategies.	S-M	CD, PW, PAR	Public
DP-P.8 Consider how temporary arts installations and/or events can help activate public and private spaces.	Ongoing	CD, ED, PAR	Public/Private
DP-P.9 Continue to use public space elements and art to strengthen the sense of place within downtown, an honor the diverse cultural community of Auburn.	Ongoing	CD, ED, PAR	Public/Private

UTILITIES RECOMMENDATIONS			
DP-U.1 Implement planned projects identified in the City's Comprehensive Plan to continue to improve water and sewer capacity in Downtown.	Ongoing	CD, PW	Public
DP-U.2 Use strategic public infrastructure to stimulate private investment in economic development and redevelopment activities in the planning area such as TIF, LID, latecomers agreements, and system oversizing. City-owned and operated utilities should continue to pursue federal, state, and private grants to finance infrastructure.	Ongoing	CD, PW	Public

10 | Appendices

Appendix A

Planned Action Environmental Impact Statement (EIS)

Appendix B

Baseline Report

EXHIBIT 3

CITY OF AUBURN

2024 DOWNTOWN SUBAREA PLAN UPDATE AND PLANNED ACTION

FINAL ENVIRONMENTAL IMPACT STATEMENT

JANUARY 2025

CITY OF AUBURN
Department of Community Development
25 W Main Street
Auburn, WA 98001

January 22, 2025

Dear Reader,

Located in the center of the Puget Sound region between Seattle and Tacoma, the City of Auburn has grown into a place of regional significance with two major rivers, access to many parks and trails, a solid business core, a committed government, and a long list of other assets and traits.

The proposed 2024 Auburn Downtown Subarea Plan Update (or Downtown Plan Update for short) explores an expanded study area of approximately 360 acres. In downtown Auburn today, a lack of economic development is both the chief impediment to sustainable growth and the most significant root cause of adverse impacts on the community and environment. The planning process is intended to create a shared long-term vision and more-coordinated approach to development, environmental review, and strategic capital investments in the Auburn downtown. Completion of the 2024 Auburn Downtown Subarea Plan Update will support innovative planning and policy interventions to help downtown achieve its tremendous potential for economic development, an outcome that will deliver a broad range of equitable social and environmental benefits at both the local and regional scales.

With the issuance of the Final Environmental Impact Statement (EIS), the City of Auburn is excited to reach this next milestone in the development of the 2024 Auburn Downtown Subarea Plan Update. The Draft EIS considered three alternatives, and the City selected Alternative 3 as the Preferred Alternative:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process was initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative was studied in the Draft EIS but was not selected as the Preferred Alternative. The description is provided here for context. This alternative represented moderate growth and proposed zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It included modifications to the DUC zone, optimizing the DUC Neighborhood Residential zone for small lot development at higher and lower levels of density in

residential areas surrounding downtown, and maintained M-1 Light Industrial areas in north downtown, while assuming the same transportation improvements as Alternative 1.

- **Preferred Alternative - Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes similar to Alternative 2 but with increased building heights, including 125-foot buildings in the DUC Med zone around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

The Draft EIS identified environmental impacts and mitigation strategies for each alternative. Environmental topics evaluated in detail in the Draft EIS included land use and transportation.

Agencies, affected Tribes, and members of the public were invited to comment on the Draft EIS. No comments were received. Project-related information can be reviewed on the project website at https://speakupauburn.org/downtownplan.

This Final EIS is now being issued. City Council action is anticipated in early 2025.

Thank you for your interest in the City of Auburn and the Downtown Subarea planning effort. We look forward to reviewing your comments.

Sincerely,

Alexandria D. Teague

Alexandria Teague/State Environmental Policy Act Responsible Official
City of Auburn, Community Development

FACT SHEET Final Environmental Impact Statement

PROJECT NAME

Auburn Downtown Subarea Plan and Planned Action Environmental Impact Statement (EIS)

DATE OF ISSUE OF FINAL EIS

January 22, 2025

PROPOSAL (PROPOSED ACTION)

The proposal is a non-project action to revise the Auburn Downtown Subarea Plan and pursue a Planned Action Ordinance. The previous Auburn Downtown Plan and EIS were adopted in 2001 and have provided the framework for development of the City's downtown for the past 20 years. The 2024 Auburn Downtown Subarea Plan Update (Downtown Plan Update) is envisioned to supplement the existing plan by providing a refreshed perspective of the land use, development, and transportation options serving the downtown area.

Project Proponent

City of Auburn

State Environmental Policy Act (SEPA) Lead Agency

City of Auburn, Auburn Washington

SEPA Responsible Official

Alexandria Teague, Planning Services Manager

Location of Background Materials

Background materials used in the preparation of this Final EIS are listed in Chapter 6, *References*.

The Draft EIS considered three alternatives and the City selected Alternative 3 as the Preferred Alternative. The alternatives were developed as a result of findings during public outreach activities and feedback and from City planning experts and land use consultants:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process is initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative represents **moderate growth** and proposes zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It includes a Main Street Overlay to encourage compatible-scale redevelopment over time, and modifications to the DUC zone, optimizing the DUC Neighborhood Residential zone for small-lot development at higher and lower levels of density in residential areas surrounding downtown. It assumes the same transportation improvements as Alternative 1.
- **Preferred Alternative - Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes similar to Alternative 2 but without a zoning overlay or specific focus on the Main Street corridor. It has increased building heights, including 125-foot buildings in the DUC Health and Wellness district around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

Each of the three alternatives was analyzed in detail in the Draft EIS for environmental elements of land use and transportation.

PERMITS, LICENSES, AND APPROVALS LIKELY REQUIRED FOR PROPOSAL

The Proposed Action consists of several related decisions by the Auburn City Council regarding the Downtown Subarea Plan Update and Planned Action:

- Approval of the Final EIS as a document that is adequate for State Environmental Policy Act (SEPA) compliance, decision-making, and implementation of the upfront SEPA process.
- Implementation of the associated Planned Action Ordinance for the project and the associated upfront SEPA compliance provision.

- Adoption of the Downtown Subarea Plan Update and the associated policies and implementing regulations, as well as site-specific projects that are proposed within the Downtown Subarea.
- Determination of whether one of the development alternatives contained in the Subarea Plan, a hybrid alternative derived from the development alternatives, or the No Action Alternative is the City's Preferred Alternative for the Downtown Subarea.

Plans must be considered and approved by the City Council after Planning Commission recommendations are made. The Washington Department of Commerce coordinates state agency review during a required 60-day review period.

PUBLIC COMMENTS ON THE DRAFT EIS AND PLANNED ACTION ORDINANCE

Written Comments		Verbal Comments	
Public Comment Period	The Draft Environmental Impact Statement (Draft EIS) was available for a 30-day public comment period starting on September 25, 2024.	Draft and Planned Action Ordinance Public Meeting	A public meeting was held to receive verbal comments on the Draft EIS and the proposed Planned Action Ordinance from the public and interested parties.
Date Written Comments Were Due	Written comments were received if postmarked by October 24, 2024. Comments were mailed to: Alexandria Teague, Planning Services Manager, 25 W Main Street, Auburn, WA 98001.	Public Meeting Date and Time	The public meeting was held on October 15, 2024, starting at 6 p.m.
Written Comment Submittal and Contact Information	Written comments were sent by email to Alexandria Teague, Planning Services Manager: planning@auburnwa.gov	Public Meeting Location	25 W Main Street, Council Chambers, Auburn, WA 98001.

DOCUMENT AVAILABILITY

The Final EIS is available online at the Auburn Community Development Department webpage: https://speakupauburn.org/downtownplan.

For questions or to obtain a copy of the document, contact Alexandria Teague, Planning Services Manager, at ateague@auburnwa.gov or 253.931.3003.

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TIMING OF ADDITIONAL ENVIRONMENTAL REVIEW

This Final EIS was prepared with updates to the environmental document and is now being issued to complete the SEPA EIS process.

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Abbreviations/Acronyms

Abbreviation/Acronym	Definition
ACC	Auburn City Code
ADA	Americans with Disabilities Act
AU	Activity Unit
AWSC	All-Way Stop Controlled
BNSF	Burlington Northern Santa Fe Railway
CDPMP	Comprehensive Downtown Parking Management Plan
City	City of Auburn
DART	Dial-A-Ride Transit
DUC	Downtown Urban Center
EIS	Environmental Impact Statement
FGTS	Freight and Goods Transportation System
GMA	Growth Management Act
LOS	level of service
MFTE	Multifamily Property Tax Exemption
MIT	Muckleshoot Indian Tribe
MultiCare	MultiCare Auburn Medical Center
PSRC	Puget Sound Regional Council
RCW	Revised Code of Washington
RGC	Regional Growth Center

Abbreviation/Acronym	Definition
RRFB	Rectangular Rapid Flashing Beacon
SEPA	State Environmental Policy Act
SR 18	State Route 18
TIP	Transportation Improvement Program
TOD	Transit-Oriented Development
TODI	Transit-Oriented Development Implementation
TWSC	Two-Way Stop Controlled
UP	Union Pacific
WAC	Washington Administrative Code
WSDOT	Washington State Department of Transportation

CHAPTER 1 Summary

1.1 Introduction

This Final Environmental Impact Statement (Final EIS) is a disclosure document for a non-project action that provides a qualitative and quantitative analysis of environmental impacts associated with the proposed 2024 Auburn Downtown Subarea Plan Update (or Downtown Plan Update for short). The Downtown Plan Update provides an updated vision for downtown Auburn that encourages more activity, housing, and economic development opportunities, and enhances livability in and around the subarea.

The Downtown Plan Update will supplement the existing (2001) Downtown Plan by providing a refreshed perspective of the land use, development, and transportation options serving the downtown area. The 2024 Auburn Downtown Subarea Plan Update is being developed for consistency with the Growth Management Act (GMA), multicounty planning policies, countywide planning policies, and the City of Auburn Comprehensive Plan.

The City of Auburn (City) is also pursuing a Planned Action EIS (as described later in this chapter) to streamline permitting and encourage more development within the Downtown Subarea. The Downtown

Plan Update will become an element of the City's Comprehensive Plan when adopted by the City of Auburn City Council.

The Draft EIS was issued in September 2024, and the City is now issuing the Final EIS with selection of Alternative 3 as the Preferred Alternative. Information and background on the Downtown Plan process and the EIS were included in Chapter 1, *Summary*, of the Draft EIS issued in September 2024, and that information is not repeated in the Final EIS.

Following the issuance of the Draft EIS and review of comments received (no comments were received), the City selected Alternative 3 as the Preferred Alternative. Updates to the Draft EIS are provided in this Final EIS.

1.2 Organization of the Final EIS

The Draft EIS laid the foundation for the initial environmental analysis that was conducted and is a companion document to this Final EIS. The information provided in this Final EIS does not duplicate or repeat information presented in the Draft EIS, except to provide context to the reader. For example, most of the original text and the appendices provided with the Draft EIS are not repeated. Rather, the information in the Final EIS presents only the updates or revisions made since the Draft EIS was issued.

The reader should refer to both the Draft EIS and the Final EIS documents in order to obtain all of the information analyzed during the EIS process.

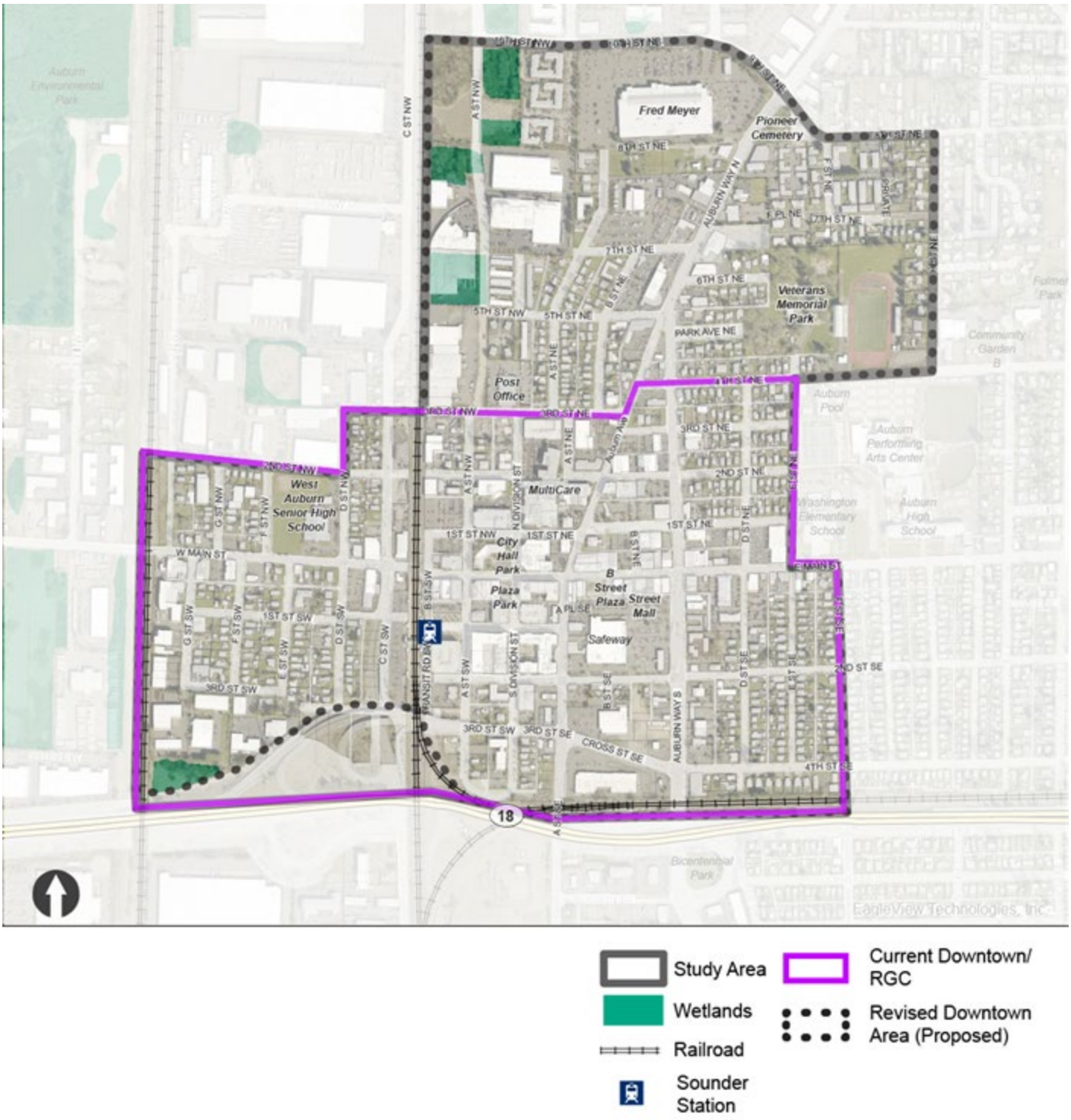
1.3 Background

The previous Auburn Downtown Plan was adopted in 2001 and has provided the framework for development of the City's downtown for the past 20 years. The plan is now reaching the end of its planning period, and the City has also changed over that time. The 2024 Auburn Downtown Subarea Plan Update will supplement the existing plan by providing a refreshed perspective of the land use, development, and transportation options serving the downtown area.

1.4 Project Location

The current Downtown Subarea encompasses approximately 230 acres. The study area includes the existing Downtown Urban Center (DUC) boundary, but expands to the north to 10th Street NE and 8th Street NE. The BNSF/Sounder rail corridor comprises the western border of the expanded area, while the eastern border is defined by H Street NE, 4th Street NE, and E Street NE. **Figure 1-1** illustrates the location and highlights three separate areas that are relevant to the Downtown Plan Update:

- **Current Downtown/Regional Growth Center (RGC):** Auburn's existing downtown and RGC area.
- **Study Area:** The entire area studied for the Downtown Plan Update that was used to determine the Downtown Subarea.
- **Revised Downtown Area:** Proposed revision of the downtown area that is studied in the EIS for Alternatives 2 and 3. This boundary is largely similar to the study area, but the plan proposes to remove a small portion along the southern boundary that is currently occupied by the BNSF railroad corridor and the State Route 18 (SR 18) cloverleaf exits and right-of-way.



SOURCE: Prepared by MAKERS (City of Auburn GIS data).

FIGURE 1-1 Map Showing Boundaries of the Study Area, Existing Downtown/RGS, and the Proposed Revised Downtown Area

1.4.1 Downtown Plan Update

The 2024 Auburn Downtown Subarea Plan Update, found in Draft EIS Appendix A, should be reviewed along with this EIS for a comprehensive understanding of all aspects of the plan and probable environmental impacts.

The fundamental goal of the Downtown Plan Update is to promote economic development. In downtown today, a lack of economic development is both the chief impediment to sustainable growth, and the most significant root cause of adverse impacts on the community and environment. The Downtown Plan Update is intended to provide innovative planning and policy interventions to help downtown achieve its tremendous potential for economic development, an outcome that will deliver a broad range of equitable social and environmental benefits at both the local and regional scales.

The 2024 Auburn Downtown Subarea Plan Update will amend current City of Auburn policies governing the environment, land use, economics, transportation, design standards, and utilities in downtown. Actions implementing the Downtown Plan Update include new regulations that address land use, transportation, housing, zoning, capital improvement programs, and other City ordinances and regulations. Many of these actions provide mitigation for impacts that may be caused by development.

The Downtown Plan Update includes the following major components:

- Goals and Objectives
- Concept
- Proposed Policies, Improvements, and Land Use Code Updates
- Implementation

The 2024 Downtown Subarea Plan effort is funded through a $250,000 Transit-Oriented Development Implementation (TODI) grant from the Washington State Department of Commerce and additional supplemental funding appropriated by City Council.

Specifics of the No Action Alternative and the Preferred Alternative that could implement the Downtown Plan Update are described in Chapter 2, *Alternatives*, of this EIS.

1.5 Downtown Plan Update Process

This section describes the planning and outreach process used to develop the Downtown Plan Update.

1.5.1 Outreach Information

The Downtown Plan was developed over an approximately 2.5-year process (It began in 2022 and is expected to be completed by summer 2025) and represents the integration of input from a broad range of stakeholders and other interested parties, as described below. Details concerning the outreach process are provided below, and additional details are available in the Downtown Plan Update.

STAKEHOLDER INTERVIEWS

- Agencies and Property Owners – July 2022
- Development Community and Housing Advocates – July 2022
- Business Community – July 2022
- City Leadership Visioning Meeting – November 2023

COMMUNITY EVENT

- Farmer's Market Engagement – August 2022
- Comprehensive Plan Update Public Open House – April 2023
- Auburn Downtown Subarea Plan Scoping Notice – October 2022

OPINION SURVEY

- Early Visioning Questions – July 2022

1.6 SEPA Process and Public Comment

The proposed non-project action consists of several related decisions by the Auburn City Council regarding the Downtown Plan Update:

- Approval of the Final EIS as a document that is adequate for State Environmental Policy Act (SEPA) compliance, decision-making, and implementation of the upfront SEPA process.
- Implementation of an associated Planned Action Ordinance.
- Adoption of the Downtown Plan Update and the associated policies and implementing regulations, as well as site-specific projects that are proposed within the Auburn Downtown Subarea.

The City is sponsoring the Downtown Plan Update and is also the SEPA Lead Agency for the 2024 Auburn Downtown Subarea Plan EIS and Planned Action. As SEPA Lead Agency, the City has determined that this non-project proposal would likely have a significant adverse impact on the environment. Preparation of an EIS is required under Revised Code of Washington (RCW) 43.21C.030 (2)(c). The Lead Agency identified the following areas for analysis in the EIS after review of feedback received during the public outreach process:

- Land Use
- Transportation

A non-project EIS, also known as a programmatic EIS, is being prepared because the Downtown Plan Update is not a specific project, but rather a land use plan. The Downtown Plan Update addresses a broad geographical area (approximately 230 acres) and includes a set of potential activities that could be implemented for future development, redevelopment, and revitalization of the Downtown

Subarea. As such, rather than a piecemeal analysis of environmental impacts and mitigation that is provided on a project-by-project or site-by-site basis, the Draft EIS comprehensively evaluates environmental impacts and identifies reasonable mitigation measures for the entire subarea based on each of the alternatives.

The Draft EIS was issued on September 25, 2024.

PUBLIC COMMENTS ON THE DRAFT EIS AND PLANNED ACTION ORDINANCE

Written Comments		Verbal Comments	
Public Comment Period	The Draft EIS was available for a 30-day public comment period starting on September 25, 2024.	Draft and Planned Action Ordinance Public Meeting	A public meeting was held to receive verbal comments on the Draft EIS and the proposed Planned Action Ordinance from the public and interested parties.
Date Written Comments Are Due	Written comments were to be received or postmarked by October 24, 2024. Comments were mailed to Alexandria Teague, Planning Services Manager, 25 W Main Street, Auburn, WA 98001.	Public Meeting Date and Time	The public meeting was held on October 15, 2024, starting at 6 p.m.
Written Comment Submittal and Contact Information	Written comments were to be sent by email to Alexandria Teague, Planning Services Manager: planning@auburnwa.gov	Public Meeting Location	25 W Main Street, Council Chambers, Auburn, WA 98001.

DOCUMENT AVAILABILITY

The Draft EIS and Final EIS are available online at the Auburn Community Development Department webpage: https://speakupauburn.org/downtownplan.

For questions or to obtain a copy of the Draft EIS or Final EIS document, contact Alexandria Teague, Planning Services Manager, at ateague@auburnwa.gov or 253.931.3003.

1.6.1 Planned Action Ordinance

This proposal includes the creation and submittal of a Planned Action Ordinance for adoption. A Planned Action Ordinance is a tool that allows local governments to streamline environmental review processes for certain types of development projects. The EIS analysis of a proposal that includes a Planned Action differs from other EISs because the impact analysis focuses largely on impacts based on future development that is expected to occur within a broad area—rather than an impact analysis associated with individual, sequential site-specific development projects. In this case, the specific geographical area is the Auburn Downtown Subarea. The objective of this EIS is to evaluate probable environmental impacts of the alternatives for the entire study area as comprehensively and completely as possible. The intent is to eliminate the need for subsequent SEPA environmental review associated with site-specific development or redevelopment. A SEPA Checklist would still be required for submittal with a project proposal, but issuance to the public would not be required if the project meets specific criteria. This is expected to provide certainty for future, site-specific development proposals and both simplify and expedite the permitting process for such projects. Expedited SEPA review applies to development that complies with criteria listed in the Planned Action Ordinance, complies with the subarea's development regulations, and occurs within 10 years of issuance of the Final EIS for this project.

1.6.2 Final EIS

The Final EIS completes the environmental review process for the proposal. It incorporates changes or clarifications regarding the Draft EIS. No comments were received during the Draft EIS. The Final EIS is the SEPA document that presents the selected Preferred Alternative, which is Alternative 3. Copies of the Final EIS will be

made available to those agencies (federal, state, regional, City), organizations, and the individuals that received the Draft EIS.

1.6.3 Summary of Impacts and Potential Mitigation Measures

This section summarizes the impacts that would potentially result from the No Action and Preferred Alternative, which is Alternative 3. This summary table is not intended to be a substitute for the discussion of the No Action and Preferred Alternative contained in Chapters 3 and 4 of the Draft EIS.

TABLE 1-1 Summary of Impacts and Mitigation Measures

Element of the Environment	No Action Alternative	Preferred Alternative
Land Use	IMPACTS	
	Does not amend current plans or regulations and is predicted to accommodate less future growth than the Preferred Alternative. If the City gets approval from the Puget Sound Regional Council (PSRC) to expand the RGC boundary to be consistent with the proposed Revised Downtown Area, but does not adopt zoning changes to increase development capacity, the area is unlikely to meet future growth targets under No Action.	Additional growth and development will occur in the proposed Revised Downtown Area, leading to increases in height and bulk of buildings and increased land use intensity.
	MITIGATION	
	The City could avoid this potentially significant impact by adopting some zoning changes to increase development capacity.	
Transportation	IMPACTS	
	The failing performance at C Street SW & 3rd Street NW, under No Action could impact transit operations.	Land use growth would result in increased vehicle volumes. One significant adverse traffic operation impact is expected: • C Street SW & 3rd Street NW – Level of Service (LOS) F exacerbated Vehicles experience excessive queuing when traveling eastbound along 3rd Street NW in the PM peak due to higher volumes and delay

Element of the Environment	No Action Alternative	Preferred Alternative
		along the rail line. Because this intersection is located along a Sound Transit express route that runs frequent service in the PM peak period, it is considered to have significant auto and transit impacts. Sound Transit Route 566 runs north/south along C Street NW, which includes the impacted intersection in the Preferred Alternative. The increased delays will impact this transit route in addition to vehicles. As a result, the Preferred Alternative would have a **significant impact on transit operations**.
	MITIGATION	
		The City could make changes to signal operations at C Street NW and 3rd Street NW. Currently, the signal operates only with protected permitted phasing when the rail crossing is activated; otherwise, it operates with permitted left-turn phasing. If the signal were updated to protect permitted left-turn phasing during peak periods, the LOS results show a D, which is acceptable under the City's LOS standards. This signal phasing update would also reduce the identified transit impact.

1.7 Significant Unavoidable Adverse Impacts

The following summarizes any potential significant adverse environmental impacts identified in this environmental analysis for the No Action and the Preferred Alternative.

1.7.1 Land Use – No Action Alternative

The No Action Alternative does not amend current plans or regulations and is predicted to accommodate less future growth than the Preferred Alternative. If the City gets approval from the Puget Sound Regional Council (PSRC) to expand the RGC boundary to be consistent with the proposed Revised Downtown Area, but

does not adopt zoning changes to increase development capacity, the area is unlikely to meet future growth targets under the No Action Alternative.

The City could avoid this potentially significant impact by adopting some zoning changes to increase development capacity.

1.7.2 Transportation – No Action Alternative

The failing performance at C Street SW & 3rd Street NW under the No Action Alternative could impact transit operations. This would result in a significant adverse impact.

1.7.3 Land Use – Preferred Alternative

Proposed redevelopment within the Auburn Downtown Subarea would result in an intensification of development, additional employment opportunities, and increased population in the Auburn downtown area. While the intensity of redevelopment would be substantially greater than the amount of existing development, such redevelopment would be consistent with the 2024 Auburn Downtown Subarea Plan Update (if adopted), the intent of the City's Comprehensive Plan and zoning, the goals and intent of PSRC's VISION 2050 regional plan for growth, and the requirements of the Washington State GMA.

With application of the land use-related mitigation, **no significant unavoidable land use impacts are expected in conjunction with the Preferred Alternative.**

1.7.4 Transportation – Preferred Alternative

Proposed redevelopment within the Auburn Downtown Subarea would result in an intensification of development, additional

employment opportunities, and increased population in the Auburn Downtown area which results in changes in transportation.

With application of appropriate mitigation measures, **no significant unavoidable adverse impacts are expected relative to vehicular traffic, rail traffic, public transit, or non-motorized systems, in conjunction with the Preferred Alternative.**

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CHAPTER 2 Alternatives and Preferred Alternative

Draft EIS Chapter 2 described the alternatives for the 2024 Downtown Subarea Plan Update. There are no major updates to the Draft EIS Chapter 2 analysis related to the alternatives. Alternative 3 was selected as the Preferred Alternative.

The alternatives were developed as a result of findings during public outreach activities and feedback and from City planning experts and land use consultants and are summarized as follows:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process is initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative represented moderate growth and proposed zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It included modifications to the DUC zone,

optimizing the DUC Neighborhood Residential zone for small lot development at higher and lower levels of density in residential areas surrounding downtown, and maintained M-1 Light Industrial areas in north downtown, while assuming the same transportation improvements as Alternative 1.

- **Preferred Alternative - Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes with increased building heights, including 125-foot buildings in the DUC Med zone around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

For the full analysis of the alternatives, please see Draft EIS Chapter 2, which is incorporated by reference in this Final EIS.

CHAPTER 3 Land Use

3.1 Introduction

The Draft EIS laid the foundation for the initial environmental analysis that was conducted and is a companion document to this Final EIS. The information provided in this Final EIS does not duplicate or repeat information presented in the Draft EIS, except to provide context to the reader. For example, most of the original text and the appendices provided with the Draft EIS are not repeated. Rather, the information in the Final EIS presents only the updates or revisions made since the Draft EIS was issued.

The reader should refer to both the Draft EIS and the Final EIS documents in order to obtain all of the information analyzed during the EIS process.

3.2 Updates to the EIS

Draft EIS Chapter 3 described the affected environment for land use, analyzes the project alternatives for potential impacts, and identifies potential mitigation measures for those adverse impacts.

There are no major updates to the Draft EIS analysis Chapter 3 related to land use patterns and urban form. Alternative 3 was selected as the Preferred Alternative. The only revision to note for this Final EIS is that one map in the Draft EIS will be updated in the final Downtown Subarea Plan, as described below.

Draft EIS, Chapter 3, Page 3-26:

- Figure 3-3, *Vacant and Redevelopable Parcels in the Study Area*, was changed to reflect that some parcels that have recent buildings on them were incorrectly shown as redevelopable. This map will be updated for the final Downtown Subarea plan. This revision is also noted in Chapter 7 for clarifications and corrections.

For the full analysis of the alternatives, please see Draft EIS Chapter 3, which is incorporated by reference in this Final EIS. Potential impacts and mitigation measures for the No Action Alternative and the Preferred Alternative are summarized in this Final EIS, Chapter 1, Table 1-1, *Summary of Potential Impacts and Mitigation Measures*.

CHAPTER 4 Transportation

4.1 Introduction

The Draft EIS laid the foundation for the initial environmental analysis that was conducted and is a companion document to this Final EIS. The information provided in this Final EIS does not duplicate or repeat information presented in the Draft EIS, except to provide context to the reader. For example, most of the original text and the appendix material provided with the Draft EIS are not repeated. Rather, the information in the Final EIS presents only the updates or revisions made since the Draft EIS was issued.

The reader should refer to both the Draft EIS and the Final EIS documents in order to obtain all of the information analyzed during the EIS process.

4.2 Updates to the EIS

Updates to the transportation analysis in the Draft EIS are included in this chapter of the Final EIS. Revisions are shown below, by Draft EIS section, formatted using underline text (for additions) and ~~strikethrough text~~ (for deletions). *Italicized text* explains what sections of the Draft EIS are revised, by section and page number.

None of the revisions change any of the conclusions from the Draft EIS analysis.

Corrections from Draft EIS, Chapter 4, Section 4.1.3, Existing Street Network, Corridor Level of Service, Page 4-4.

~~CORRIDOR~~ LEVEL OF SERVICE

The City uses an LOS rating system as a way to evaluate the operations of its roadway system. LOS is a concept used to describe traffic operations from the driver's perspective. LOS ratings are defined by intersection delay in seconds—LOS ranges from LOS A, which signifies no congestion and little delay, to LOS F, which signifies substantial congestion and delay. **Table 4-1** summarizes the LOS and delay thresholds specified in the Highway Capacity Manual, which is a standard methodology for measuring intersection performance.

TABLE 4-1 LOS and Delay Thresholds for Signalized and Unsignalized Intersections

LOS	Description	Signalized Intersections (Delay in Seconds)	Unsignalized Intersections (Delay in Seconds)
A	Free-flowing Conditions	<10	0–10
B	Stable Flow (slight delays)	>10–20	>10–15
C	Stable Flow (acceptable delays)	>20–35	>15–25
D	Approaching Unstable Flow (tolerable delay)	>35–55	>25–35
E	Unstable Flow (intolerable delay)	>55–80	>35–50
F	Forced Flow (congested and queues fail to clear)	>80	>50

SOURCE: Highway Capacity Manual 6th Edition

The City tracks LOS in two ways:

- For some intersections along its major corridors, it considers the volume-weighted delay of intersections along a corridor.
- For other intersections along major corridors, it evaluates those intersections separately.

Per the 2021 Comprehensive Transportation Plan, ~~C~~corridor LOS and isolated intersection LOS are the primary measurements that the City uses to identify needed improvements for roadway capacity. All arterials and collectors in Auburn have designated LOS standards. Within the study area, most corridors have a LOS standard of D; however, some corridors and isolated intersections are permitted to operate at LOS E or F. These LOS standards are consistent with the 2001 Auburn Downtown Plan.

The City measures intersections' operations based on delays measured during the weekday PM peak hour.

Traffic operations were analyzed using the Synchro 11 software package and *Highway Capacity Manual* methodology. The Synchro network reflects the study area's existing roadway network, including segment and intersection geometry, and signal timings. The network also includes existing traffic volumes that were collected in spring and summer 2022. For signalized and all-way stop-controlled intersections, the LOS is based on the average delay for all movements. For minor street stop-controlled intersections, LOS is based on the movement with the highest delay.

This study considers 30 existing intersections, 26 of which are signalized. Table 4-2 summarizes the existing corridor 2022 LOS for study intersections in the PM peak hour in respective corridor segments and existing intersection LOS for study intersections that do not fall within a concurrency corridor.

Figure 4-2 summarizes the existing intersection LOS in the PM peak hour at the study intersections. The LOS analysis indicates that vehicles move through the study area with relatively little delay during the PM peak hour. All corridors currently meet the City's minimum LOS standards. One intersection does not meet the City's minimum LOS standards.

TABLE 4-2 2022 Downtown Auburn ~~Corridor~~ Level of Service

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	Average LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS					
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C/24
		4	Signal		
		5	Signal		
		6	Signal		
3	Auburn Way S from E Main St to M St SE	7	Signal	F~~D~~	C/28
		9**	Signal		
		6	Signal		
		8	Signal		
		10	Signal		
10	Auburn Ave/A St from 6th St SE to E Valley Access Rd	1**	Signal	D	A/9
11	Main St from West Valley Hwy to R St	18	Signal	D	C/20
		19	Signal		
		20	Signal		
		6	Signal		
		21	Signal		
13	C St SW from Ellingson Rd to SR 18	25**	Signal	D	B/15
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC***	D	C/22
		14	Signal		

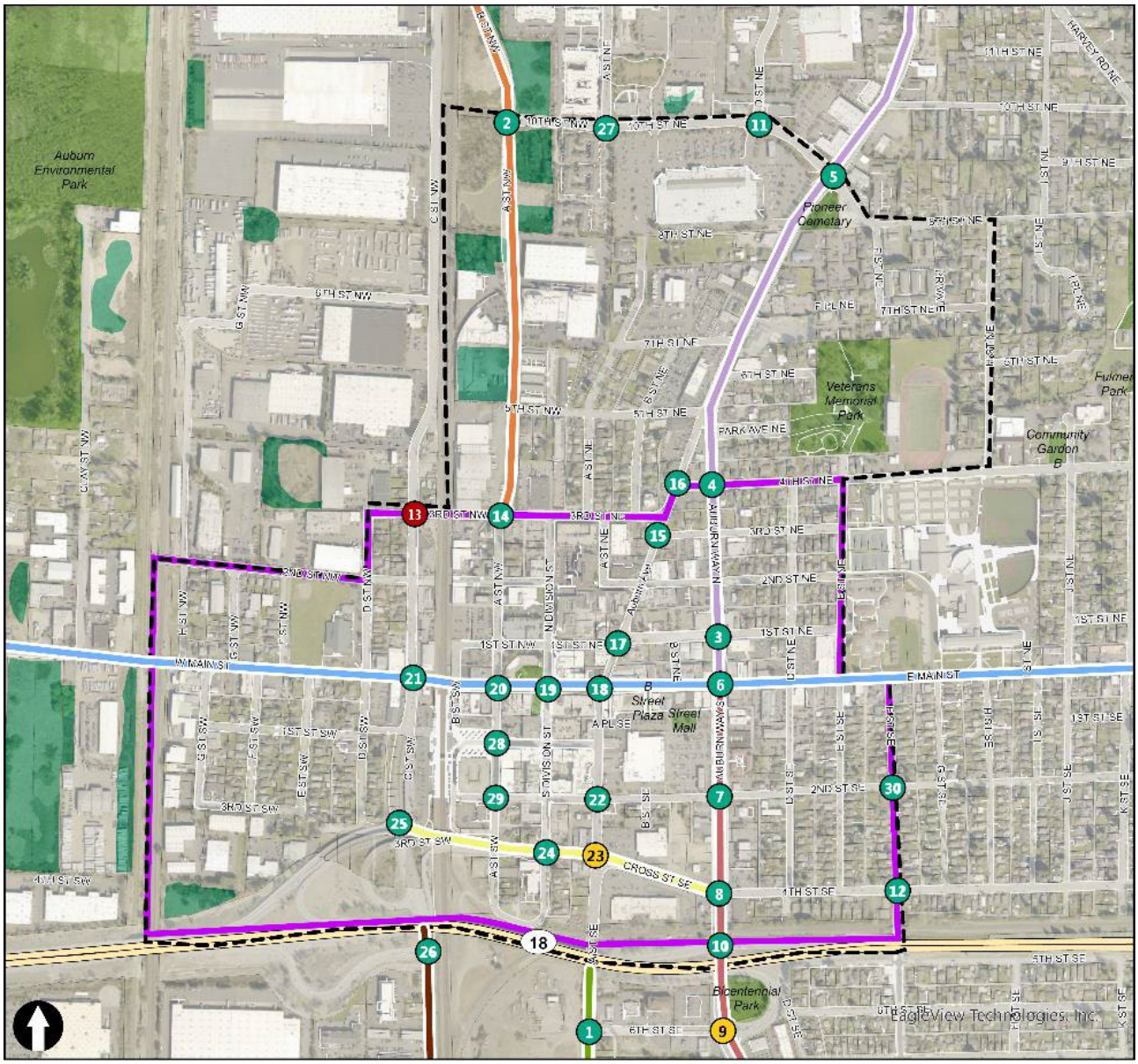
Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	Average LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to Auburn Way S	23	Signal	FE	B/19
		24	Signal		
		8	Signal		
		25	Signal		
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS					
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B/20
N/A	F St SE & 4th St SE	12	Signal	DE	B/15
N/A	C St SW & 3rd St NE	13	Signal	DE	F/90
N/A	Auburn Ave & 3rd St NE	15	Signal	DE	B/14
N/A	Auburn Ave & 4th St NE	16	Signal	DE	A/4
N/A	Auburn Ave & 1st St NE	17	Signal	DE	A/9
N/A	A St SE & 2nd St SE	22	Signal	D	C/30
N/A	10th St NE & A St NE	27	TWSC	D	B/11
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC****	D	A/8
N/A	A St SE & 2nd St SE	29	Signal	D	B/13
N/A	F St SE & 2nd St SE	30	AWSC	D	A/8

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

~~** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan.~~

~~*** Two-Way Stop Controlled.~~

~~**** All-Way Stop Controlled.~~



NOTE: Downtown Urban Center area shown on this map is consistent with the Current Downtown/ RGC area shown on other maps.

ExistingLOS
- A - C
- D
- F
- Study Area
- Downtown Urban Center
- SR-18
- Parks
- Wetlands

LOS Corridor
- 2
- 3
- 10
- 11
- 13
- 18
- 31

FIGURE 4-2 Intersection Level of Service Existing PM Peak Hour

Corrections from Draft EIS, Chapter 4, Section 4.1.3, Existing Street Network, Bicycle Network, Page 4-9.

BICYCLE NETWORK

Providing better accommodations for people who wish to travel by bike is a priority for the City. Current infrastructure benefits from access to regional trails such as the Interurban Trail directly west of downtown. ~~However, there are few existing bicycle facilities in the City, with only existing sharrows and bike lanes in the study area.~~ There are also two multiuse trails in proximity to the study area as seen in **Figure 4-5.**

Corrections from Draft EIS, Chapter 4, Section 4.1.5, Safety, Page 4-13.

4.1.5 Safety

Safety is a high priority for the City to promote a downtown environment that accommodates multiple transportation modes. ~~The City's comprehensive plan policies include a goal to "*significantly reduce or eliminate traffic fatalities and serious injuries through a safe systems approach.*"~~ Figure 4-7 shows the locations in downtown Auburn with the highest density of collisions, as reported in the City's 2020 Local Road Safety Plan. As shown by the heatmap, many collisions occurred along principal and minor arterial roadways, as well as major intersections. At-grade rail crossing intersections were also evaluated for safety, including several in the downtown study area. There have been recent upgrades to the rail crossings, such as pre-signals that prevent vehicles from stopping on the crossing.

Corrections from Draft EIS, Chapter 4, Section 4.1.8, Relevant Studies, Project-Specific Plans, Page 4-21.

PROJECT-SPECIFIC PLANS

Auburn Station Parking and Access Improvements

Auburn Station is a train station served by S Line of the Sounder commuter rail network. It is located southwest of downtown Auburn and consists of two train platforms, a bus station, a parking garage, a public plaza, and a pedestrian bridge. Sound Transit is improving access to the Auburn Sounder Station for riders, whether they access the station by walking, bicycling, connecting buses or driving. This project includes a new parking garage located at 1st Street NW and is expected to be completed by 2027.

This parking garage will add parking to the existing Auburn Station parking garage, which was filled to capacity just before the COVID-19 pandemic and may return to this condition, especially with future additions to Sounder service and as the costs of traveling by car increase. ~~This parking garage will add parking as the existing Auburn Station parking garage is filled to capacity during the morning commute for riders using the Sounder S Line train travelling between Lakewood and downtown Seattle.~~ This train completes 13 roundtrips each weekday and runs special service for select events. Construction is expected to start as early as 2024 with opening to the public in 2027.

Corrections from Draft EIS, Chapter 4, Section 4.1.8, Relevant Studies, Local and Jurisdiction and Agency Plans, Auburn Comprehensive Plan – Transportation Element, Page 4-22.

LOCAL JURISDICTION AND AGENCY PLANS

Auburn Comprehensive Plan – Transportation Element (2015)

The Auburn Comprehensive Plan was adopted in 2015 and recently updated in December 2021. Starting in summer 2022, the City of Auburn embarked on a major update to its Comprehensive Plan~~, last updated in 2015~~. This process is running concurrent to the analysis and planning work done for the 2024 Auburn Downtown Subarea Plan Update. The City coordinated the two planning efforts, and the Downtown Plan Update is central to helping the City meet the Comprehensive Plan's 2044 growth targets.

The Comprehensive Transportation Plan as updated in December 2021 describes existing transportation conditions and future changes and needs as they relate to growth in the City. December 2021 updates included changes to the existing transportation network, an updated current needs evaluation, and identification of standards for future development and infrastructure improvement scenarios.

Corrections from Draft EIS, Chapter 4, Section 4.1.8, Relevant Studies, Local Jurisdiction and Agency Plans, East Main Street Traffic Analysis (2024), Page 4-26.

East Main Street Traffic Analysis (2024)

The 2024 East Main Street Traffic Analysis ~~recommends~~ looked at traffic operations related to options for changing traffic patterns along E Main Street to provide more space for people walking and biking and promote commercial activity along this key business corridor. The City conducted a preliminary traffic analysis of

modifying E Main Street from Auburn Avenue to Auburn Way. Four options were studied in the analysis:

- Option 1 – Keep the road in its existing two-way traffic configuration.
- Option 2 – Close the road to all vehicle traffic.
- Option 3 – Close the road to eastbound traffic.
- Option 4 – Close the road to westbound traffic.

All scenarios utilized the 2044 Draft-Preferred Land Use Alternative Scenario (2044 Land Use) from the City's 2024 Draft Comprehensive Plan Update as the background traffic demand model, which is also consistent with the methodology used for this Draft-EIS. This preliminary traffic analysis shows that, from a traffic operations perspective, Options 1 and 3 are feasible. However, a more detailed traffic analysis would be required prior to implementation of any changes.

Corrections from Draft EIS, Chapter 4, Section 4.2.2, Impacts of the No Action Alternative, Intersection LOS, Page 4-29.

~~Intersection~~ LOS

Table 4-6 summarizes the average vehicle delay for each study intersection/corridor compared to its LOS standard in the PM peak hour. By 2044, traffic volumes would increase due to the land use growth that would occur within downtown Auburn and other parts of the City as well as regional growth not associated with Auburn. Therefore, delay at most intersections is expected to increase to some degree. Operations at two intersections would fall below the City's standard:

- C Street SW & 3rd Street NW – LOS F
- A Street NE & 10th Street NE – LOS E

Figure 4-10 shows intersection operations, in terms of LOS for Alternative 1. Note that colors represent LOS grades, not whether operations meet the City's standard.

TABLE 4-6 2044 Alternative 1, No Action, PM Peak Hour ~~Corridor~~ Level of Service and Delay

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS						
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C / 24	C / 24
		4	Signal			
		5	Signal			
		6	Signal			
3	Auburn Way S from E Main St to M St SE	7	Signal	FD	C / 28	D / 38
		9**	Signal			
		6	Signal			
		8	Signal			
		10	Signal			
10	Auburn Ave/A St from 6th St SE to E Valley Access Rd	1**	Signal	D	A / 9	B / 11
11	Main St from West Valley Hwy to R St	18	Signal	D	C / 20	C / 23
		19	Signal			
		20	Signal			
		6	Signal			
		21	Signal			
13	C St SW from Ellingson Rd to SR 18	25**	Signal	D	B / 19	C / 22
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC	D	C / 22	C / 21
		14	Signal			

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to AWS	23	Signal	~~F~~E	B / 19	C / 23
		24	Signal			
		8	Signal			
		25	Signal			
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS						
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B / 19	B / 19
N/A	F St SE & 4th St SE	12	Signal	~~D~~E	B / 15	B / 19
N/A	C St SW & 3rd St NE	13	Signal	~~D~~E	F / 90	F / >120
N/A	Auburn Ave & 3rd St NE	15	Signal	~~D~~E	B / 14	B / 12
N/A	Auburn Ave & 4th St NE	16	Signal	~~D~~E	A / 4	A / 4
N/A	Auburn Ave & 1st St NE	17	Signal	~~D~~E	A / 9	B / 12
N/A	A St SE & 2nd St SE	22	Signal	D	C / 30	C / 30
N/A	10th St NE & A St NE	27	TWSC	D	B / 11	E / 40
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC	D	A / 8	B / 10
N/A	A St SE & 2nd St SE	29	Signal	D	B / 13	B / 18
N/A	F St SE & 2nd St SE	30	AWSC	D	A / 8	A / 8

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

~~** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan~~

Corrections from Draft EIS, Chapter 4, Section 4.2.2, Impacts of the No Action Alternative, Transit, Page 4-33.

Transit

In 2044, King County Metro will operate a new RapidRide route in Auburn. The proposed route is prepared to launch in 2026 and will run north/south through Auburn, with a starting point at Auburn Station and terminus in the Renton Transit Center. The route will run primarily along Auburn Way N.

King County Metro Route 181 is under consideration for a future RapidRide, within the agency's interim network, and will likely be a RapidRide line ~~before~~ after 2044. The agency is currently evaluating the potential RapidRide lines in the interim network and will make a decision in 2025 as to which line will move into the planning phase next. Route 181 connects the Federal Way Transit Center to the Auburn Transit Center and Green River College, serving the Lea Hill area of Auburn.

The failing performance at C Street SW & 3rd Street NW~~E~~, under Alternative 1 could impact transit operations.

Corrections from Draft EIS, Chapter 4, Section 4.2.3, Impacts of Alternatives 2 and 3, 2044 Alternative 3 Results, Page 4-34.

One significant adverse traffic operation impact is expected under Alternative 3 (and shown in **bold** in **Table 4-7**):

- C Street ~~S~~NW & 3rd Street NW – LOS F exacerbated

This intersection is signalized. Vehicles experience excessive queuing when traveling eastbound along 3rd Street NW in the PM peak due to higher volumes and delay along the rail line. Because this intersection is located along a Sound Transit express route that runs frequent service in the PM peak period, it is considered to have significant auto and transit impacts.

A review of traffic operations shows a similar deficiency under Alternative 1. Potential measures to mitigate the impact on the impacted intersection are presented in the *Mitigation Measures* section.

TABLE 4-7 2022 Downtown Auburn ~~Corridor~~ Level of Service

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)	2044 Alternative 3 LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS							
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C / 24	C / 24	C / 30
		4	Signal				
		5	Signal				
		6	Signal				
3	Auburn Way S from E Main St to M St SE	7	Signal	F~~D~~	C / 28	D / 38	D / 38
		9~~**~~	Signal				
		6	Signal				
		8	Signal				
		10	Signal				
10	Auburn Ave/A St from 6th St SE to E Valley Access Road	1~~**~~	Signal	D	A / 9	B / 11	A / 14
11	Main St from West Valley Hwy to R St	18	Signal	D	C / 20	C / 23	D / 36
		19C	Signal				
		20	Signal				
		6	Signal				
		21	Signal				
13	C St SW from Ellingson Rd to SR 18	25~~**~~	Signal	D	B / 15	C / 22	C / 20
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC	D	C / 22	C / 21	C / 35
		14	Signal				

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)	2044 Alternative 3 LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to AWS	23	Signal	~~F~~E	B / 19	C / 23	C / 31
		24	Signal				
		8	Signal				
		25	Signal				
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS							
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B / 20	B / 19	C / 24
N/A	F St SE & 4th St SE	12	Signal	~~D~~E	B / 15	B / 19	C / 28
N/A	C St SW & 3rd St NE	13	Signal	~~D~~E	F / 90	F / >120	F / >120
N/A	Auburn Ave & 3rd St NE	15	Signal	~~D~~E	B / 14	B / 12	B / 15
N/A	Auburn Ave & 4th St NE	16	Signal	~~D~~E	A / 4	A / 4	A / 5
N/A	Auburn Ave & 1st St NE	17	Signal	~~D~~E	A / 9	B / 12	C / 22
N/A	A St SE & 2nd St SE	22	Signal	D	C / 30	C / 30	D / 43
N/A	10th St NE & A St NE	27	TWSC	D	B / 11	E / 40	D / 33
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC	D	A / 8	B / 10	B / 12
N/A	A St SE & 2nd St SE	29	Signal	D	B / 13	B / 18	B / 18
N/A	F St SE & 2nd St SE	30	AWSC	D	A / 8	A / 8	A / 9

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

~~** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan.~~

Corrections from Draft EIS, Chapter 4, Section 4.3.1, Mitigation Measures, Incorporated Plan Features, Page 4-39.

4.3.1 Incorporated Plan Features

The City could make changes to signal operations at C Street NW and 3rd Street NW. Currently, the signal operates only with protected permitted phasing when the rail crossing is activated; otherwise, it operates with permitted left-turn phasing. If the signal were updated to protected permitted left-turn phasing during peak periods, the LOS results show a D, which is acceptable under the City's LOS standards. This signal phasing update would also reduce the identified transit impact. This change would require widening the roadway and replacement of the traffic signal.

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CHAPTER 5 Distribution List

The Final EIS has been issued with a notice of availability, consistent with Washington Administrative Code (WAC 197-11-460), including distribution to the following:

TRIBAL AND FEDERAL AGENCIES

- Federal Emergency Management Agency
- Muckleshoot Indian Tribe Environmental Department Fisheries Office, Planning, Cultural Program, Fisheries Division
- U.S. Army Corps of Engineers, Seattle District Regulatory Branch
- U.S. Department of Agriculture Natural Resources Conservation Service

REGIONAL AND COUNTY AGENCIES

- Auburn School District
- King County Area Developer Services, Department of Natural Resources, Department of Permitting and Environmental Review, Environmental Health Division, Local Services, Metro, Waste Division, Wastewater Treatment Division
- Lakehaven Utility District Development Engineering
- Lake Meridian Water District

- Pierce County Master Builder Association
- Pierce Transit, Land Use Review Capital Development
- Puget Sound Clean Air Agency
- Puget Sound Regional Council
- Soos Creek Water and Sewer District
- Sound Transit
- South King Housing and Homelessness Partners

STATE OF WASHINGTON

- Department of Archaeology and Historic Preservation
- Department of Commerce
- Department of Ecology
- Department of Fish and Wildlife
- Department of Health
- Department of Natural Resources
- Department of Social and Health Services Land and Buildings Division
- Department of Transportation

CITY OF AUBURN, AUBURN SERVICE PROVIDERS, ADJACENT CITIES

- City of Algona
- City of Bonney Lake Planning and Community Development
- City of Federal Way Community Development
- City of Kent Planning Department
- City of Kent School District
- City of Pacific Community Development

OTHER INTERESTED PARTIES

- Alpine Ridge Insurance Agency
- Washington Environmental Council
- Futurewise
- Rainier Audubon
- King County and Snohomish County Master Builder Association

The Final EIS has also been made available at speakupauburn.org/downtownplan, and a notice of availability was sent to all commentors during the public scoping process and the interested parties contact list:

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CHAPTER 6 References

This chapter includes references for citations for both the Draft EIS and the Final EIS, for completeness.

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CITY OF AUBURN

2024 DOWNTOWN SUBAREA PLAN UPDATE

DRAFT ENVIRONMENTAL IMPACT STATEMENT

SEPTEMBER 2024

CITY OF AUBURN
Department of Community Development
25 W Main Street
Auburn, WA 98001

September 25, 2024

Dear Reader,

Located in the center of the Puget Sound region between Seattle and Tacoma, the City of Auburn has grown into a place of regional significance with two major rivers, access to many parks and trails, a solid business core, a committed government, and a long list of other assets and traits.

The proposed 2024 Auburn Downtown Subarea Plan Update (or Downtown Plan Update for short) explores and expanded study area of approximately 360 acres. In downtown Auburn today, a lack of economic development is both the chief impediment to sustainable growth and the most significant root cause of adverse impacts on the community and environment. The planning process is intended to create a shared long-term vision and more-coordinated approach to development, environmental review, and strategic capital investments in the Auburn downtown. Completion of the 2024 Auburn Downtown Subarea Plan Update will support innovative planning and policy interventions to help downtown achieve its tremendous potential for economic development, an outcome that will deliver a broad range of equitable social and environmental benefits at both the local and regional scales.

With the issuance of the Draft Environmental Impact Statement (EIS), the City of Auburn is excited to reach this next milestone in the development of the 2024 Auburn Downtown Subarea Plan Update. The Draft EIS considers three alternatives:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process is initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative represents **moderate growth** and proposes zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It includes modifications to the DUC zone, optimizing the DUC Neighborhood Residential zone for small-lot development at higher and lower levels of density in residential areas surrounding downtown, and maintains M-1 Light Industrial areas in north downtown, while assuming the same transportation improvements as Alternative 1.

- **Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes similar to Alternative 2 but with increased building heights, including 125-foot buildings in the DUC Med zone around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

The Draft EIS identifies environmental impacts and mitigation strategies for each alternative. Environmental topics evaluated in detail in the Draft EIS include land use and transportation.

Agencies, affected Tribes, and members of the public are invited to comment on the Draft EIS. You may comment on the alternatives, probable significant adverse impacts, proposed mitigation measures, and licenses or other approvals that may be required. All comments are due no later than 5 p.m. on October 24, Pacific Standard Time (PST). In addition, the City invites you to learn more about and comment on the proposal at an upcoming public comment meeting:

Draft EIS Public Comment and Planned Action Meeting: 6 p.m. PST, October 15, 2024, at 25 W. Main St., Council Chambers, Auburn, WA. The purpose of the meeting is to receive verbal comments on the Draft EIS from the public and interested parties and inform about the Planned Action. Project-related information can be reviewed on the project website at https://speakupauburn.org/downtownplan.

Following the Draft EIS comment period, a Final EIS will be prepared that responds to all the comments received during the Draft EIS public comment period. City Council action is anticipated in late 2024 or early 2025.

Thank you for your interest in the City of Auburn and the Downtown Subarea planning effort. We look forward to reviewing your comments.

Sincerely,

Alexandria D. Teague

Alexandria Teague/State Environmental Policy Act Responsible Official
City of Auburn, Community Development

FACT SHEET Draft Environmental Impact Statement

PROJECT NAME

Auburn Downtown Subarea Plan Environmental Impact Statement (EIS)

DATE OF ISSUE OF DRAFT EIS

September 25, 2024

PROPOSAL (PROPOSED ACTION)

The proposal is a non-project action to revise the Auburn Downtown Subarea Plan and pursue a Planned Action Ordinance. The previous Auburn Downtown Plan and EIS were adopted in 2001 and have provided the framework for development of the City's downtown for the past 20 years. The 2024 Auburn Downtown Subarea Plan Update (Downtown Plan Update) is envisioned to supplement the existing plan by providing a refreshed perspective of the land use, development and transportation options serving the downtown area.

Project Proponent

City of Auburn

State Environmental Policy Act (SEPA) Lead Agency

City of Auburn, Auburn Washington

SEPA Responsible Official

Alexandria Teague, Planning Services Manager

Location of Background Materials

Background materials used in the preparation of this Draft EIS are listed in Chapter 6, *References*.

The Draft EIS considers three alternatives. The alternatives were developed as a result of findings during public outreach activities and feedback and from City planning experts and consultant land use consultants:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process is initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative represents **moderate growth** and proposes zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It includes a Main Street Overlay to encourage compatible scale redevelopment over time, and modifications to the DUC zone, optimizing the DUC Neighborhood Residential zone for small-lot development at higher and lower levels of density in residential areas surrounding downtown. It assumes the same transportation improvements as Alternative 1.
- **Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes similar to Alternative 2 but without a zoning overlay or specific focus on the Main Street corridor. It has increased building heights, including 125-foot buildings in the DUC Health and Wellness district around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

Each of the three alternatives is analyzed in detail for environmental elements of land use and transportation.

PERMITS, LICENSES, AND APPROVALS LIKELY REQUIRED FOR PROPOSAL

The Proposed Action consists of several related decisions by the Auburn City Council regarding the Downtown Subarea Plan Update and Planned Action:

- Approval of the Final EIS as a document that is adequate for SEPA compliance, decision making, and implementation of the upfront SEPA process;
- Implementation of the associated Planned Action ordinance for the project and the associated upfront SEPA compliance provision;

- Adoption of the Downtown Subarea Plan Update and the associated policies and implementing regulations, as well as site-specific projects that are proposed within the Downtown Subarea; and
- Determination of whether one of the development alternatives contained in the Subarea Plan, a hybrid alternative derived from the development alternatives, or the No Action Alternative is the City's preferred alternative for the downtown subarea.

Plans must be considered and approved by the City Council after Planning Commission recommendations are made. The Washington Department of Commerce coordinates state agency review during a required 60-day review period.

PUBLIC COMMENTS ON THE DRAFT EIS AND PLANNED ACTION ORDINANCE

WRITTEN COMMENTS		VERBAL COMMENTS	
Public Comment Period	This Draft Environmental Impact Statement (Draft EIS) will be available for a 30-day public comment period starting on September 25, 2024.	Draft and Planned Action Ordinance Public Meeting	A public meeting will be held to receive verbal comments on the Draft EIS and the proposed Planned Action Ordinance from the public and interested parties.
Date Written Comments Are Due	Written comments must be received or postmarked by October 24, 2024. Please mail to: Alexandria Teague, Planning Services Manager, 25 W Main Street, Auburn, WA 98001.	Public Meeting Date and Time	The public meeting will be held on October 15, 2024, starting at 6 p.m.
Written Comment Submittal and Contact Information	Written comments may be sent by email to Alexandria Teague, Planning Services Manager: planning@auburnwa.gov	Public Meeting Location	25 W Main Street, Council Chambers, Auburn, WA 98001.

DOCUMENT AVAILABILITY

The Draft EIS is available online at the Auburn Community Development Department webpage: https://speakupauburn.org/downtownplan.

For questions or to obtain a copy of the document, contact Alexandria Teague, Planning Services Manager, at ateague@auburnwa.gov or 253.931.3003.

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TIMING OF ADDITIONAL ENVIRONMENTAL REVIEW

After the Draft EIS comment period concludes, the City of Auburn (Lead Agency) will review and respond to comments. A Final EIS will be prepared that contains the responses to the comments and potential updates to the environmental document. The City of Auburn anticipates releasing the Final EIS in late 2024 or early 2025.

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Abbreviations/Acronyms

Abbreviation/Acronym	Definition
ACC	Auburn City Code
ADA	Americans with Disabilities Act
AU	Activity Unit
AWSC	All-Way Stop Controlled
BNSF	Burlington Northern Santa Fe Railway
BRT	bus rapid transit
CDPMP	Comprehensive Downtown Parking Management Plan
DART	Dial-A-Ride Transit
DUC	Downtown Urban Center
FGTS	Freight and Goods Transportation System
GMA	Growth Management Act
HB	House Bill
LOS	level of service
MFTE	Multifamily Property Tax Exemption
MIT	Muckleshoot Tribal
MultiCare	MultiCare Auburn Medical Center
PSRC	Puget Sound Regional Council
RCW	Revised Code of Washington
RGC	Regional Growth Center

Abbreviation/Acronym	Definition
RRFB	Rectangular Rapid Flashing Beacon
SR 18	State Route 18
TIP	Transportation Improvement Program
TOD	Transit-Oriented Development
TODI	Transit-Oriented Development Implementation
TWSC	Two-Way Stop Controlled
UP	Union Pacific
VMT	vehicle miles traveled
WAC	Washington Administrative Code
WSDOT	Washington State Department of Transportation

CHAPTER 1 Summary

1.1 Introduction

This Draft Environmental Impact Statement (Draft EIS) is a disclosure document for a non-project action that provides a qualitative and quantitative analysis of environmental impacts associated with the proposed 2024 Auburn Downtown Subarea Plan Update (or Downtown Plan Update for short). The Downtown Plan Update provides an updated vision for downtown Auburn that encourages more activity, housing, and economic development opportunities, and enhances livability in and around the subarea.

The Downtown Plan Update will supplement the existing (2001) Downtown Plan by providing a refreshed perspective of the land use, development, and transportation options serving the downtown area. The 2024 Auburn Downtown Subarea Plan Update is being developed for consistency with the Growth Management Act (GMA), multicounty planning policies, countywide planning policies, and the City of Auburn Comprehensive Plan.

The City of Auburn (City) is also pursuing a Planned Action EIS (as described later in this chapter) to streamline permitting and encourage more development within the downtown subarea. The Downtown

Plan Update will become an element of the City's Comprehensive Plan when adopted by the City of Auburn City Council.

See **Figure 1-1** for a visual display of the steps in the planning process.

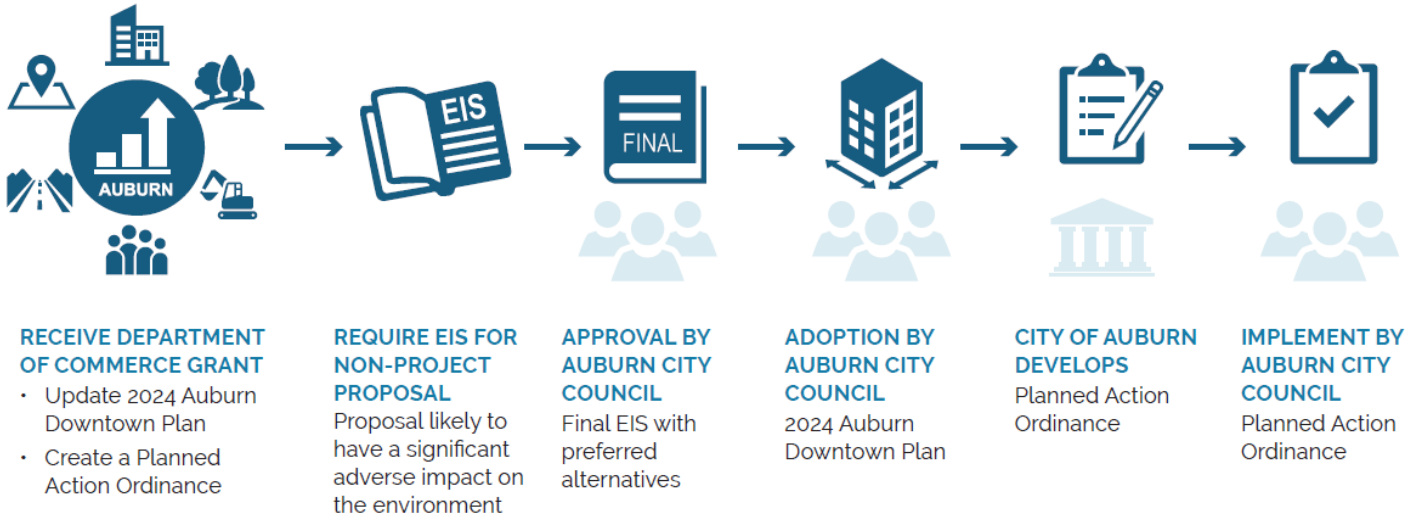


FIGURE 1-1 **Downtown Subarea Plan Process**

1.2 Background

The previous Auburn Downtown Plan was adopted in 2001 and has provided the framework for development of the City's downtown for the past 20 years. The plan is now reaching the end of its planning period, and the City has also changed over that time. The 2024 Auburn Downtown Subarea Plan Update will supplement the existing plan by providing a refreshed perspective of the land use, development, and transportation options serving the downtown area.

1.3 Project Location

The Downtown Subarea encompasses approximately 230 acres. The study area includes the existing Downtown Urban Center (DUC) boundary, but expands to the north to 10th Street NE and 8th Street NE. The BNSF/Sounder rail corridor comprises the western border of

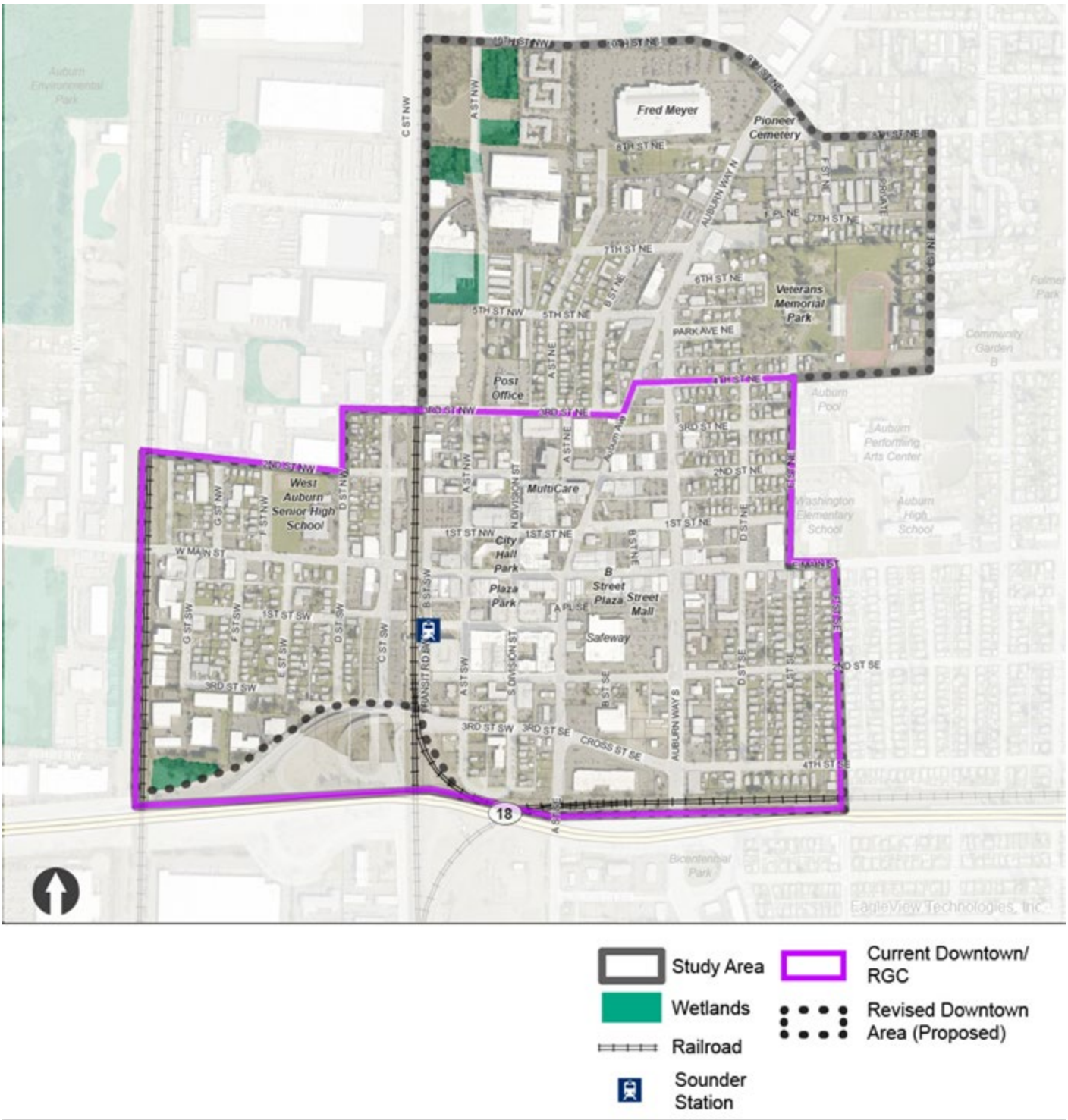
the expanded area, while the eastern border is defined by H Street NE, 4th Street NE, and E Street NE. **Figure 1-2** illustrates the location and highlights three separate areas that are relevant to the Downtown Plan Update:

- **Current Downtown/Regional Growth Center (RGC):** Auburn's existing downtown and RGC area.
- **Study Area:** The entire area studied for the Downtown Plan Update and covered by the Baseline Report (Appendix B.)
- **Revised Downtown Area:** Proposed revision of the downtown area that is studied in the Draft EIS. This boundary is largely similar to the study area, but the plan proposes to remove a small portion along the southern boundary that is currently occupied by the BNSF railroad corridor and the State Route 18 (SR 18) cloverleaf exits and right-of-way.

1.3.1 Downtown Plan Update

The 2024 Auburn Downtown Subarea Plan Update, found in Appendix A, should be reviewed along with this EIS for a comprehensive understanding of all aspects of the plan and probable environmental impacts.

The fundamental goal of the Downtown Plan Update is to promote economic development. In downtown today, a lack of economic development is both the chief impediment to sustainable growth, and the most significant root cause of adverse impacts on the community and environment. The Downtown Plan Update is intended to provide innovative planning and policy interventions to help downtown achieve its tremendous potential for economic development, an outcome that will deliver a broad range of equitable social and environmental benefits at both the local and regional scales.



SOURCE: Prepared by MAKERS (City of Auburn GIS data).

FIGURE 1-2 Map Showing Boundaries of the Study Area, Existing Downtown/RGS, and the Proposed Revised Downtown Area

The 2024 Auburn Downtown Subarea Plan Update will amend current City of Auburn policies governing the environment, land use, economics, transportation, design standards, and utilities in downtown. Actions implementing the Downtown Plan Update include new regulations that address land use, transportation, housing, zoning, capital improvement programs, and other City ordinances and regulations. Many of these actions are intended to provide mitigation for impacts that may be caused by development.

The Downtown Plan Update includes the following major components:

- Goals and Objectives
- Concept
- Proposed Policies, Improvements, and Land Use Code Updates
- Implementation

The 2024 Downtown Subarea Plan effort is funded through a $250,000 Transit-Oriented Development Implementation (TODI) grant from the Washington State Department of Commerce and additional supplemental funding appropriated by City Council.

Specifics of the No Action Alternative and the two development alternatives that could implement the Downtown Plan Update are described in Chapter 2, *Alternatives*, of this EIS.

1.3.2 Regional Planning Context

The 2024 Auburn Downtown Subarea Plan Update provides an updated vision for downtown that encourages more activity, housing, and economic development opportunities, and enhances livability in and around the subarea. The plan is designed to:

1. Satisfy the requirements of the state's GMA for Auburn to plan for forecasted growth.

2. Support the goals of the Puget Sound Regional Council's (PSRC's) VISION 2050 and Transportation 2050 (T2050) regional plans. PSRC has designated downtown Auburn as an RGC, one of 29 locations throughout the region that have key "business, governmental and cultural facilities and are planning for growth."

King County is required to comply with the GMA. One of the compliance measures is to establish countywide planning policies in conjunction with the cities and towns in the county. Each city, including the City of Auburn, is assigned the household unit and employment growth allocations for the cities within its jurisdiction. VISION 2050 and T2050 provide regional planning frameworks that support accommodation of forecasted growth in a manner that results in the greatest overall benefits to the Central Puget Sound region. Both regional plans were analyzed and approved through extensive EIS processes. See Figure 1-3.

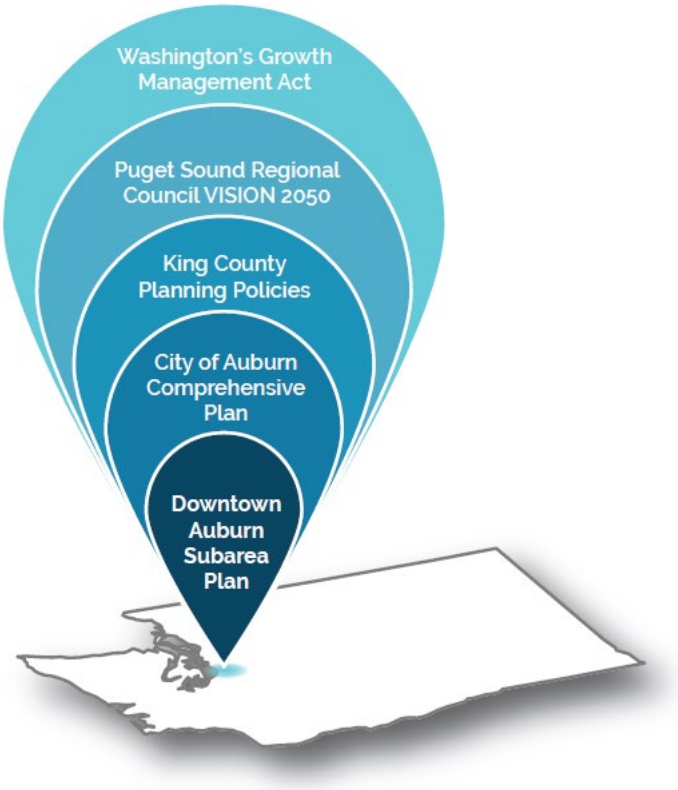


FIGURE 1-3 Planning Framework

The 2024 Auburn Downtown Subarea Plan Update and Draft EIS provide the local focus and additional analysis necessary to coordinate and bridge planning efforts from the state, regional, and local levels.

1.3.3 Goals of the Downtown Plan Update

The goals, policies, and recommendations of the 2024 Auburn Downtown Subarea Plan Update are in alignment with the preferred strategies and outcomes of VISION 2050 and T2050. The overall goal of the Downtown Plan Update is to promote a positive transformation of downtown Auburn. Specific goals include the following:

LAND USE AND ECONOMIC DEVELOPMENT GOALS

- Create new and diverse housing options throughout downtown Auburn.
- Promote a thriving business community.
- Provide sufficient future growth capacity to retain Auburn's RGC designation.
- Promote land uses that provide capacity for share of citywide 2044 household and employment targets to encourage robust growth around the existing and planned transit resources and reduce Vehicle Miles Traveled (VMT).

TRANSPORTATION GOALS

- Improve access to transit service throughout Downtown Auburn.
- Improve pedestrian and bike mobility and safety.
- Encourage sustainable transportation options.

URBAN DESIGN AND COMMUNITY LIVABILITY

- Promote comfort and safety to ensure that downtown Auburn is welcoming to all.
- Ensure that downtown Auburn remains a livable community as redevelopment continues and expands.
- Create new opportunities for social gathering and community-wide celebrations.
- Encourage growth while maintaining Auburn's hometown feel and sense of place.

Typical development-related EISs conducted in the past commonly presumed that the "No Action" Alternative served as a baseline with no specific revisions to current conditions. In contrast, in downtown Auburn, there could be a well-planned, ambitious redevelopment expected to maximize net environmental and community benefits, and to promote the most sustainable outcomes for both people and the planet.

EISs are typically focused on local impacts, but development in downtown Auburn would result in significant positive effects at the regional scale. Because the Downtown Plan Update is grounded in the approved regional growth strategies of VISION 2050 and T2050, these regional benefits merit substantial consideration in the EIS analysis.

1.4 Downtown Plan Update Process

This section describes the planning and outreach process used to develop the Downtown Plan Update.

1.4.1 Outreach Information

The Downtown Plan Update was developed over an approximately one-year-long process and represents integration of input from a broad range of stakeholders and other interested parties, as

described below. Details concerning the outreach process are provided below, and additional details are available in the Downtown Plan Update.

STAKEHOLDER INTERVIEWS

- Agencies and Property Owners – July 2022
- Development Community and Housing Advocates – July 2022
- Business Community – July 2022
- City Leadership Visioning Meeting – November 2023

COMMUNITY EVENT

- Farmer's Market Engagement – August 2022
- Comprehensive Plan Update Public Open House – April 2023
- Auburn Downtown Subarea Plan Scoping Notice – October 2022

OPINION SURVEY

- Early Visioning Questions – July 2022

1.5 SEPA Process and Public Comment

The proposed non-project action consists of several related decisions by the Auburn City Council regarding the Downtown Plan Update:

- Approval of the Final EIS as a document that is adequate for State Environmental Policy Act (SEPA) compliance, decision-making, and implementation of the upfront SEPA process.
- Implementation of an associated Planned Action Ordinance.
- Adoption of the Downtown Plan Update and the associated policies and implementing regulations, as well as site-specific projects that are proposed within the Auburn Downtown Subarea.

The City is sponsoring the Downtown Plan Update and is also the SEPA Lead Agency for the 2024 Auburn Downtown Subarea Plan & Planned Action EIS Update. As SEPA Lead Agency, the City has determined that this non-project proposal would likely have a significant adverse impact on the environment. Preparation of an EIS is required under Revised Code of Washington (RCW) 43.21C.030 (2)(c). The Lead Agency has identified the following areas for analysis in the EIS after review of feedback received during the public outreach process:

- Land Use
- Transportation

A non-project EIS, also known as a programmatic EIS, is being prepared because the Downtown Plan Update is not a specific project, but rather a land use plan. The Downtown Plan Update addresses a broad geographical area (approximately 230 acres) and includes a set of potential activities that could be implemented for future development, redevelopment, and revitalization of the Downtown Subarea. As such, rather than a piecemeal analysis of environmental impacts and mitigation that is provided on a project-by-project or site-by-site basis, this Draft EIS comprehensively evaluates environmental impacts and identifies reasonable mitigation measures for the entire subarea based on each of the alternatives.

1.5.1 Planned Action Ordinance

This proposal includes the creation and submittal of a Planned Action Ordinance for adoption. A Planned Action Ordinance is a tool that allows local governments to streamline environmental review processes for certain types of development projects. The EIS analysis of a proposal that includes a Planned Action differs from other EISs because the impact analysis focuses largely on impacts based on future development that is expected to occur within a broad area—rather than impact analysis associated with individual, sequential site-specific development projects. In this case, the specific geographical

area is the Auburn Downtown Subarea. The objective of this Planned Action EIS is to evaluate probable environmental impacts of two development alternatives and the No Action Alternative for the entire study area as comprehensively and completely as possible. The intent is to eliminate the need for subsequent SEPA environmental review associated with site-specific development or redevelopment. A SEPA Checklist would still be required for submittal with a project proposal but issuance to the public would not be required if the project meets specific criteria. This is expected to provide certainty for future, site-specific development proposals and both simplify and expedite the permitting process for such projects. Expedited SEPA review applies to development that complies with criteria listed in the Planned Action Ordinance, complies with the subarea's development regulations, and occurs within 10 years of issuance of the Final EIS for this project.

The EIS process consists of three phases: EIS Scoping, the Draft EIS, and the Final EIS. Each phase is briefly described below.

1.5.2 EIS Scoping

This is the first crucial step in the EIS process. This step defines the alternatives and the range of environmental issues to be evaluated in the EIS. The purpose of scoping is to narrow the focus of the EIS—to address only those environmental parameters that could be significantly affected as a result of the alternatives. The EIS Scoping process for this proposal occurred October 5 through October 26, 2022. At the conclusion of the scoping process, the City confirmed the scope of the EIS.

1.5.3 Draft EIS

The Draft EIS represents the City's best determination of probable significant environmental impacts associated with each of the Downtown Plan Update alternatives. The alternatives are described in Chapter 2, *Alternatives*, of this Draft EIS, and each alternative is

evaluated based on environmental parameters in Chapter 3, *Land Use*, and Chapter 4, *Transportation*, in this Draft EIS.

Public comments are invited on this Draft EIS. Copies of this Draft EIS have been made available to agencies (federal, state, regional, City), organizations, and the public for a 30-day public review and comment period. All public comments received during the Draft EIS comment period will be considered and addressed in the Final EIS. Information on comment submittal is included in the SEPA Fact Sheet at the beginning of this Draft EIS document.

1.5.4 Final EIS

The Final EIS completes the environmental review process for the proposal. It incorporates changes or clarifications regarding the Draft EIS; includes all comment letters and testimony that are received from agencies, organizations, and individuals during the public comment period; and contains responses to the comments raised during the Draft EIS. The Final EIS is the SEPA document that the City will use to decide on the Preferred Alternative. Copies of the Final EIS will be made available to those agencies (federal, state, regional, City), organizations, and the individuals that received the Draft EIS and/or provided comments on the Draft EIS.

1.5.5 Summary of Impacts and Potential Mitigation Measures

This section summarizes the impacts that would potentially result from the alternatives analyzed in this Draft EIS. This summary table is not intended to be a substitute for the complete discussion of each element that is contained in Chapters 3 and 4.

TABLE 1-1 Summary of Impacts and Mitigation Measures

Element of the Environment	No Action Alternative	Alternative 1	Alternative 2
Land Use	IMPACTS		
	Does not amend current plans or regulations and is predicted to accommodate less future growth than the two action alternatives. If the City gets approval from PSRC to expand the RGC boundary to be consistent with the proposed Revised Downtown Area, but does not adopt zoning changes to increase development capacity, the area is unlikely to meet future growth targets under No Action. MITIGATION The City could avoid this potentially significant impact by adopting some zoning changes to increase development capacity.	Additional growth and development will occur in the proposed Revised Downtown Area, leading to increases in height and bulk of buildings and increased land use intensity.	Same as Alternative 1.
Transportation	IMPACTS		
	The failing performance at C Street SW & 3rd Street NE, under could impact transit operations	Operations at two intersections would fall below the City's standard: • C Street SW & 3rd Street NW – LOS F • A Street NE & 10th Street NE – LOS E In 2044, growth under Alternative 2 is expected to be moderate and less intense than growth in Alternative 3 but still considered a significant impact.	Land use growth would result in increased vehicle volumes. One significant adverse traffic operation impact is expected: • C Street SW & 3rd Street NW – LOS F exacerbated Vehicles experience excessive queuing when traveling eastbound along 3rd Street NW in the PM peak due to higher volumes and delay along the rail line. Because this intersection is located along a Sound Transit express route that runs frequent service in the PM peak period, it is considered to have significant auto and transit impacts. Sound Transit Route 566 runs north/south along C Street NW, which includes the impacted intersection in Alternative 3. The increased delays will impact this transit route in addition to vehicles. As a result, Alternative 3 would have

Element of the Environment	No Action Alternative	Alternative 1	Alternative 2
			a **significant impact on transit operations**. MITIGATION The City could make changes to signal operations at C Street NW and 3rd Street NW. Currently, the signal operates only with protected permitted phasing when the rail crossing is activated; otherwise, it operates with permitted left-turn phasing. If the signal were updated to protect permitted left-turn phasing during peak periods, the LOS results show a D, which is acceptable under the City's LOS standards. This signal phasing update would also reduce the identified transit impact.

1.6 Significant Unavoidable Adverse Impacts

The following summarizes the potential significant adverse environmental impacts identified in this environmental analysis.

1.6.1 Land Use

Proposed redevelopment within the Auburn Downtown Subarea would result in an intensification of development, additional employment opportunities, and increased population in the Auburn downtown area. While the intensity of redevelopment would be substantially greater than the amount of existing development, such redevelopment would be consistent with the 2024 Auburn Downtown Subarea Plan Update (if adopted), the intent of the City's Comprehensive Plan and zoning, the goals and intent of PSRC's VISION 2050 regional plan for growth, and the requirements of the Washington State GMA.

With application of the land use-related mitigation, **no significant unavoidable land use impacts are expected in conjunction with any of the alternatives**.

1.6.2 Transportation

Proposed redevelopment within the Auburn Downtown Subarea would result in an intensification of development, additional employment opportunities, and increased population in the Auburn Downtown area which results in changes in transportation.

With application of appropriate mitigation measures, **no significant unavoidable adverse impacts are expected relative to vehicular traffic, waterborne/rail traffic, public transit, non-motorized systems, or parking**.

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CHAPTER 2 Alternatives

This chapter provides detailed information on the different alternatives analyzed for the 2024 Auburn Downtown Subarea Plan Update. The Draft EIS considers three alternatives. The alternatives were developed as a result of findings during public outreach activities and feedback and from City planning experts and consultant land use consultants:

- **Alternative 1:** This alternative represents the **baseline** (called the No Action Alternative in EIS terms) or the policies, regulations, and programs in effect when the EIS process is initiated. This alternative retains the current zoning, laws, and policies of the 2001 Auburn Downtown Plan, maintaining the existing Downtown Urban Center (DUC) and its mixed-use areas. This alternative assumes growth within the capacity of the DUC and existing zoning, with planned transportation projects such as the A Street Loop, 3rd Street NE/Auburn Avenue, Auburn Way S/6th Street SE, and 10th Street NE non-motorized improvements.
- **Alternative 2:** This alternative represents **moderate growth** and proposes zoning changes to allow taller buildings in the proposed Revised Downtown Area, with a focus on mixed-use development. It includes modifications to the DUC zone, optimizing the DUC Neighborhood Residential zone for small-lot development at higher and lower levels of density in residential

areas surrounding downtown, and maintains M-1 Light Industrial areas in north downtown, while assuming the same transportation improvements as Alternative 1.

- **Alternative 3:** This alternative represents the **highest growth** among all the alternatives and proposes zoning changes similar to Alternative 2 but with increased building heights, including 125-foot buildings in the DUC Med zone around the MultiCare Auburn Medical Center hospital cluster and 75-foot buildings in the north downtown mixed-use node. It assumes the same transportation improvements as Alternative 1.

Each of the alternatives is described in more detail below.

2.1 Description of Alternatives

2.1.1 Alternative 1 – No Action

LAND USE

The No Action Alternative studies the expected growth under existing zoning, laws, and policies if the City were to make no changes to the (2021) Auburn Downtown Plan.

The 2001 Auburn Downtown Plan envisioned a core area of growth in downtown Auburn, which was then implemented in the current zoning code. The Downtown Urban Center (DUC) Comprehensive Plan land use designation generally aligns with the 2001 Downtown Plan boundaries, and multiple zoning districts, including DUC, implement the DUC land use via a strong mixed-use area with a range of commercial, office, medical, retail, residential, and civic uses. The DUC core area is flanked by lower density commercial and residential uses to the east and west. A small area of M-1 industrial zoning exists in the west downtown area.

Areas north of 3rd Street NE were not included in the 2001 Downtown Plan and reflect a lower density mix of land uses.

Residential zones east of Auburn Way N include R7 Residential, R10 Residential, and R20 Residential. West of Auburn Way N is a mix of zones that support commercial and industrial uses, including C-1 Commercial, C-3 Commercial, Residential Office, and M-1 Light Industrial. Existing zoning in the study area is shown in **Figure 2-1**.

The DUC also aligns with the PSRC's RGC area. Auburn was first designated an RGC in 2003 and is now considered the Urban Growth Center type of RGC, following the PSRC's Regional Centers Framework Update in 2018. Alternative 1 retains the City's current RGC boundary, as shown in Figure 2-1.

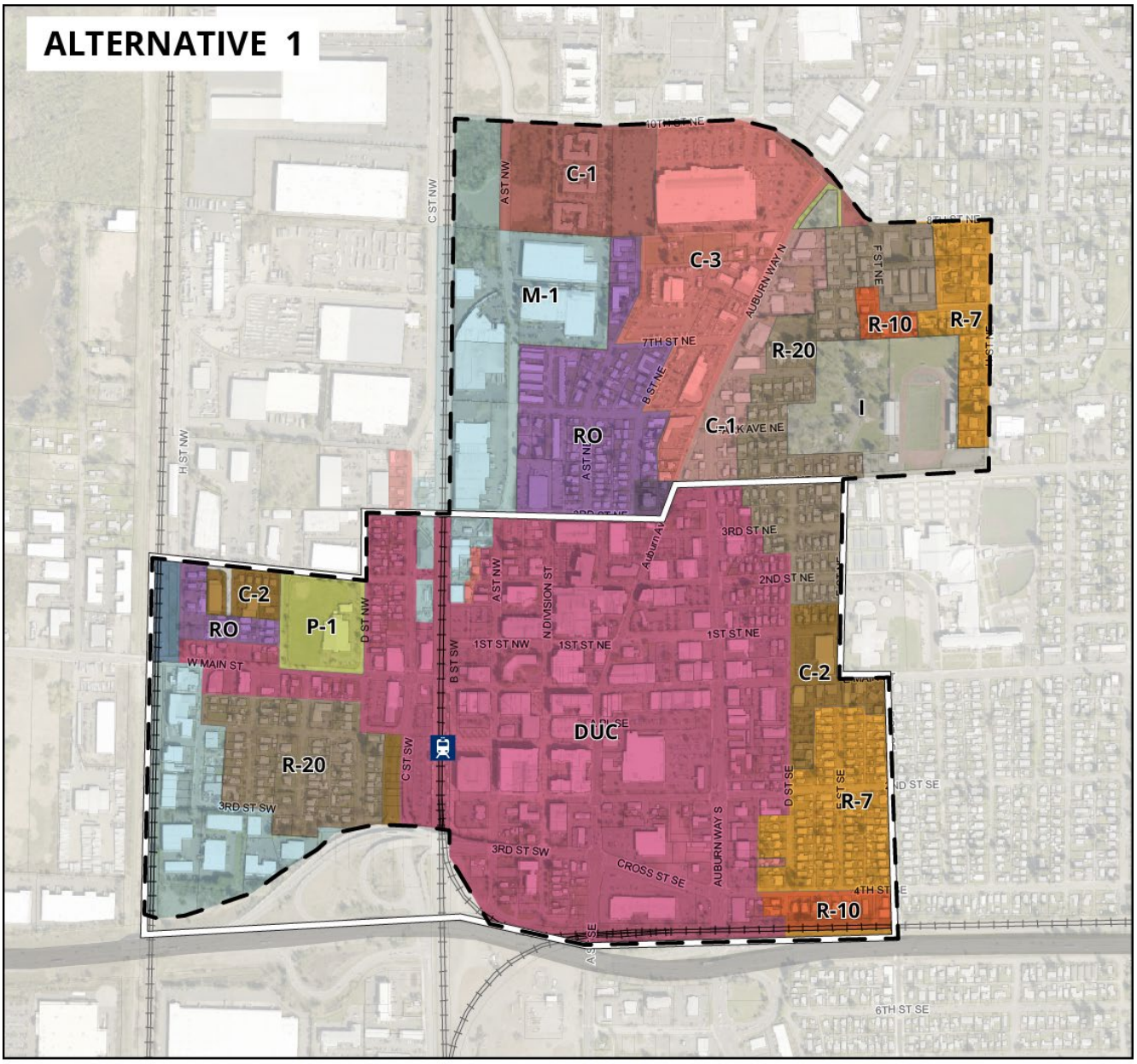
TRANSPORTATION

Several transportation projects are planned within the proposed Revised Downtown Area over the next several years. Alternative 1 – No Action assumes the following transportation projects in its modeling assumptions.

- A Street Loop
- 3rd Street NE/Auburn Avenue
- Auburn Way S/6th Street SE
- 10th Street NE Non-Motorized Improvements

GROWTH

Auburn has grown substantially over the last 20 years, but capacity for growth remains both within the existing DUC area and in adjacent commercial and residential zones in the study area. Alternative 1 – No Action considers growth (housing and jobs) that is likely accommodated by existing zoning. See **Table 2-1**.



SOURCE: MAKERS 2023

FIGURE 2-1 Existing Zoning in the Study Area

TABLE 2-1 No Action Alternative Housing and Jobs Capacity, 2021–2044

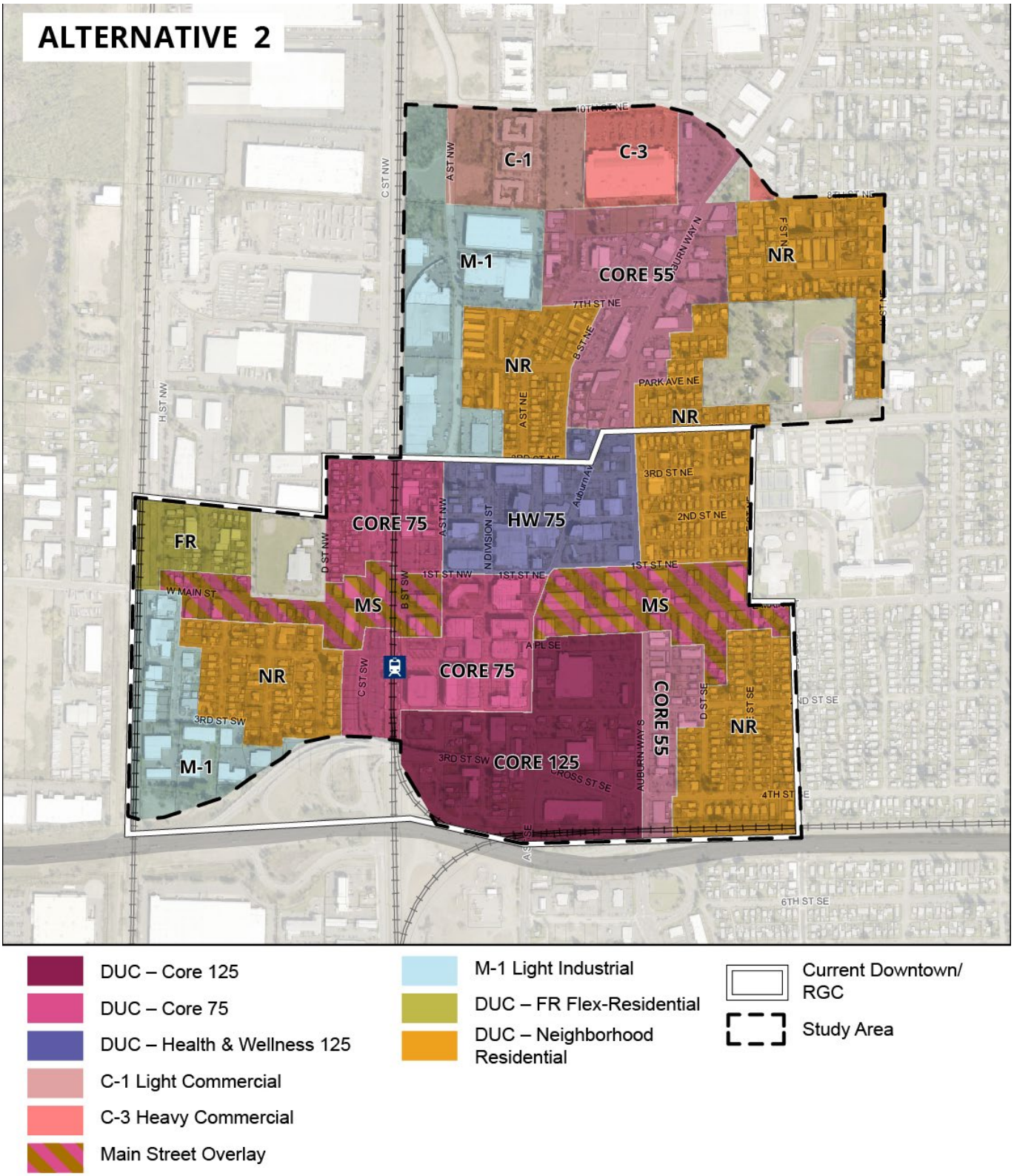
	Total Acres	Housing Units	Population	Jobs	Total Activity Units (AU)	Activity Units/Acre
2021 – Revised Downtown Area (Proposed)	361	1,724	3,708	4,799	8,507	22.6
Existing RGC Only (2021)	233	1,033	2,253	3,554	5,807	24.9
2044 – Revised Downtown Area (Proposed)	361	4,257	8,781	6,302	15,083	41.5
Existing RGC Only (2044)	233	3,226	4,749	4,749	11,395	48.9

2.1.2 Alternative 2 – Moderate Growth

LAND USE

Proposed zoning with Alternative 2 – Moderate Growth would allow taller buildings in several locations within the proposed Revised Downtown Area (see **Figure 2-2**). A modified DUC zone in the south-central part of the proposed Revised Downtown Area would allow buildings up to 125 feet in height. Alternative 2 would create a new node of mixed-use development in the north downtown portion of the proposed Revised Downtown Area centered around Auburn Way N by extending a modified DUC zone that allows buildings up to 55 feet in height. Alternative 2 also includes a new modified version of the DUC zone oriented toward hospital/medical uses in the north-central part of the downtown core around the MultiCare Auburn Medical Center (MultiCare) hospital complex.

Along the east and west Main Street corridor, a new overlay would enhance the area's traditional pedestrian-oriented retail format while allowing new development of a compatible scale. This zone would allow buildings up to 55 feet in height, which is lower than currently allowed. This zone would support the goal of creating an arts-focused area east of A Street SE.



SOURCE: MAKERS 2023

FIGURE 2-2 Proposed Zoning under Alternative 2

In residential areas surrounding downtown, the DUC Neighborhood Residential zone would be optimized for small-lot development at higher and lower levels of density. This would align with the City's Housing Action Plan Implementation effort and meet the new state requirements of House Bill (HB) 1110 (2023) by promoting small apartments, townhouses, duplexes, triplexes, and small-lot homes within existing residential zones. A new Flex residential zone would allow middle housing types as well as some light industrial/ commercial uses that are compatible with residential areas, such as a workshop space, brewery, or small office.

M-1 Light Industrial areas in north downtown would be largely unchanged, except for slight revisions along 3rd Street NW to consolidate properties zoned as M-1 to be north of the 3rd Street NW corridor in this area. The C-1 and C-3 zones at the northern edge of the proposed Revised Downtown Area would remain unchanged; new uses are slightly restricted by the Auburn Municipal Airport and the Airport Overlay Zone.

"Missing Middle" Housing Defined

The term "missing middle" housing refers to a range of housing types that fall between single-family homes and mid-rise to high-rise apartment buildings. Examples include duplexes, triplexes, townhomes, and small apartments. Daniel Parolek coined the term in 2010.

In 2023, the Washington State Legislature passed HB 1110, which required cities of certain sizes, including Auburn, to "allow multiple dwelling units per lot in a middle housing type of form." (Commerce, Middle Housing In WA: Fact Sheet for Implementing E2SHB 1110. July 2023.)

https://deptofcommerce.app.box.com/s/yjo6h53f2jhj1xopbc6lxzo28dsh2h9k.

TRANSPORTATION

Alternative 2 – Moderate Growth assumes the same transportation improvements as the No Action Alternative. See Chapter 4, *Transportation*, for an analysis of impacts and potential mitigation actions. In 2044, growth under Alternative 2 is expected to be moderate and less intense than growth in Alternative 3.

GROWTH

Alternative 2 is expected to result in moderate growth within the proposed Revised Downtown Area. See **Table 2-2** for potential zoned capacity.

TABLE 2-2 Alternative 2 Housing and Jobs Capacity, 2021–2044

	Total Acres	Housing Units	Population	Jobs	Total Activity Units (AU)	Activity Units/Acre
2021 Revised Downtown Area (Proposed)	361	1,724	3,708	4,799	8,507	22.6
2021 Existing RGC	233	1,033	2,253	3,554	5,807	24.9
2044 Projection: Revised Downtown Area (Proposed)	361	7,006	14,284	7,698	21,982	58.5
2044 Projection: Existing RGC	233	4,820	9,836	6,125	15,961	68.5

NOTE ON ANALYSIS

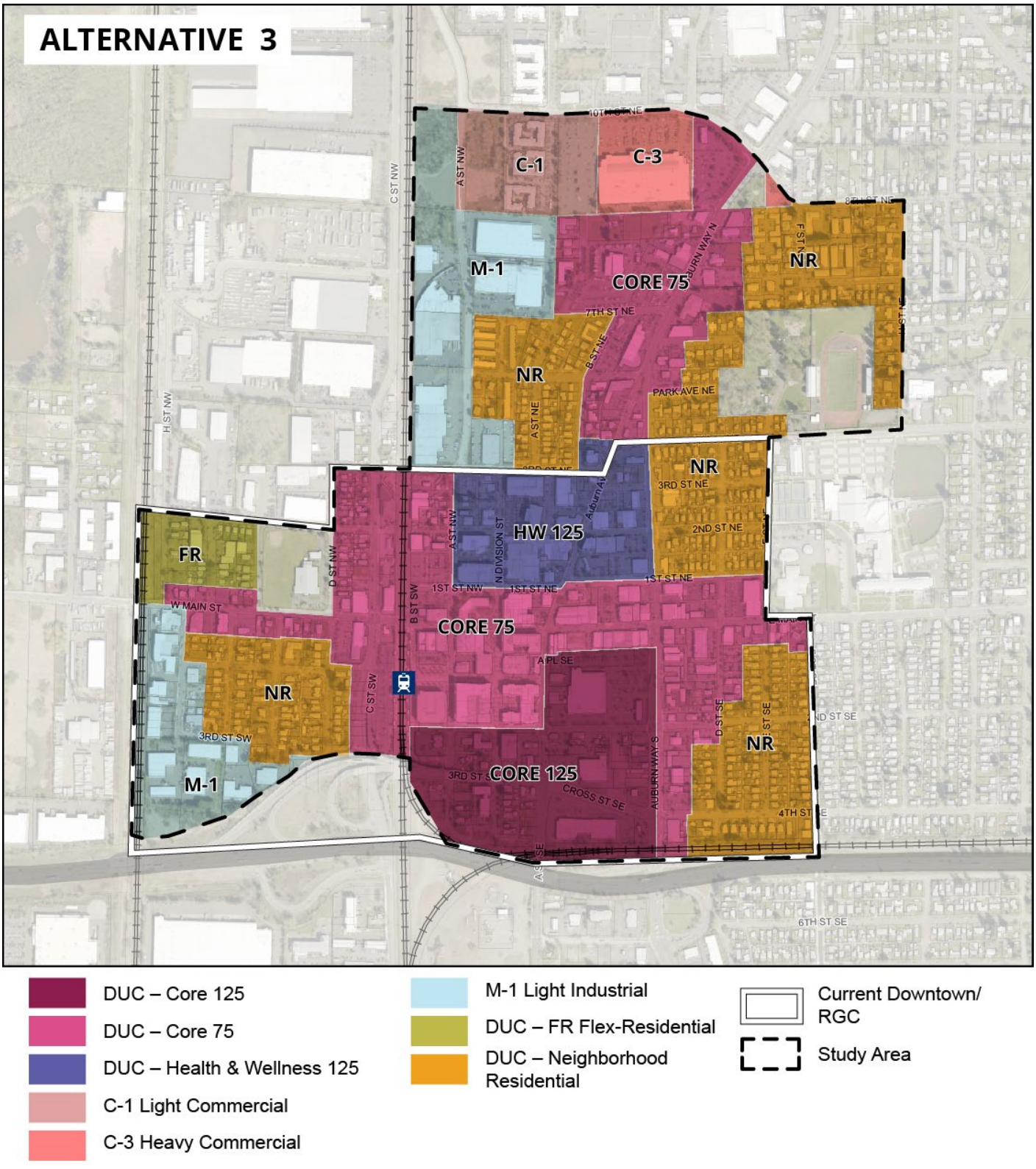
Alternative 2 represents a mid-point between the projected growth of the two bookend alternatives: Alternative 1 – No Action and Alternative 3 – Higher Growth. As a result, the analysis of this alternative in the Draft EIS is based on the transportation model information and other data gathered for the higher and lower growth alternatives. Since Alternative 2 represents a mid-point between both alternatives, the degree of impacts would be less than or equal to Alternative 3.

2.1.3 Alternative 3 – Higher Growth

LAND USE

Proposed zoning in Alternative 3 – Higher Growth is similar to Alternative 2 in many aspects but includes the following distinctions (see **Figure 2-3**):

- Increases allowable building heights to 125 feet in the DUC Med zone around the MultiCare hospital cluster in the central part of the proposed Revised Downtown Area, north of City Hall.
- Retains much of existing DUC zone and expands the DUC 75 feet across the Main Street corridor.
- Allows buildings up to 75 feet in height in the north downtown mixed-use node.



SOURCE: MAKERS 20

FIGURE 2-3 Proposed Zoning under Alternative 3

TRANSPORTATION

Alternative 3 assumes the same transportation improvements as Alternative 1 – No Action. Alternative 3 represents the highest growth among all alternatives and would experience one potential transportation-related impact. See Chapter 4, *Transportation*, for analysis of impacts and potential mitigation actions.

GROWTH

Alternative 3 is expected to result in moderate growth within the proposed Revised Downtown Area. See **Table 2-3** for potential zoned capacity.

TABLE 2-3 Alternative 3 Housing and Jobs Capacity, 2021–2044

	Total Acres	Housing Units	Population	Jobs	Total Activity Units (AU)	Activity Units/Acre
2021 Revised Downtown Area (Proposed)	361	1,724	3,708	4,799	8,507	22.6
2021 Existing RGC	233	1,033	2,253	3,554	5,807	24.9
2044 Projection: Revised Downtown Area (Proposed)	361	7,603	15,478	8,185	23,663	62.9
2044 Projection: Existing RGC	233	5,202	10,601	6,364	16,965	72.8

2.2 Comparison of Alternatives

TABLE 2-4 Comparison of Alternatives

	Total Acres	Housing Units	Population	Jobs	Total Activity Units (AU)	Activity Units/Acre
Alternative 1 - No Action (2044 Projection)	361	4,257	8,781	6,302	15,083	41.5
Alternative 2 – Moderate Growth (2044 Projection)	361	7,006	14,284	7,698	21,982	58.5
Alternative 3 – Higher Growth (2044 Projection)	361	7,603	15,478	8,185	23,663	62.9

CHAPTER 3 Land Use

This chapter describes the affected environment, potential impacts, and mitigation measures for land use in the Downtown Subarea.

Following a description of current conditions (affected environment), the analysis compares and contrasts the alternatives in a non-project analysis and provides mitigation measures for identified impacts. It also summarizes whether there are significant unavoidable adverse impacts.

This chapter also addresses physical land use patterns within and surrounding the study area, considering changes in the type and intensity of residential, commercial, and mixed uses. Existing land use pattern conditions are based on field reconnaissance by MAKERS staff members, imagery review, and King County and City of Auburn parcel data.

Future conditions consider the level of growth and land use change described in Chapter 2 for the alternatives.

3.1 Affected Environment

This section addresses land use patterns and development character in downtown Auburn and provides a baseline for analyzing the impacts of land use and development of the alternatives. It also

provides applicable plans and policies and reviews Auburn's Comprehensive Plan growth strategy and policies and PSRC's center growth strategy.

3.1.1 Land Use Plans and Policies — Regulatory Environment

GROWTH MANAGEMENT ACT

The Washington State Growth Management Act (GMA) requires comprehensive plans, including subarea plans like the 2024 Downtown Subarea Plan, and development regulations to be consistent with the following goals (as set forth in RCW 36.70A.020), as well as the goals and policies of the Shoreline Management Act, regarding shorelines of the state (as set forth in RCW 90.58.020). The goals address well-managed urban, rural, and resource lands and promote environmental quality by focusing growth in urban areas, advancing housing and employment opportunities, providing adequate public services, and more.

- **Urban Growth.** Encourage development in urban areas where adequate public facilities and services exist or can be provided in an efficient manner.
- **Reduce Sprawl.** Reduce the inappropriate conversion of undeveloped land into sprawling, low-density development.
- **Transportation.** Encourage efficient multimodal transportation systems that are based on regional priorities and coordinated with county and city comprehensive plans.
- **Housing.** Encourage the availability of affordable housing to all economic segments of the population of the state, promote a variety of residential densities and housing types, and encourage preservation of existing housing stock.
- **Economic Development.** Encourage economic development throughout the state that is consistent with adopted comprehensive plans; promote economic opportunity for all

citizens of this state, especially for unemployed and for disadvantaged persons; promote the retention and expansion of existing businesses and recruitment of new businesses; recognize regional differences impacting economic development opportunities; and encourage growth in areas experiencing insufficient economic growth, all within the capacities of the state's natural resources, public services, and public facilities.

- **Property Rights.** Private property shall not be taken for public use without just compensation having been made. The property rights of landowners shall be protected from arbitrary and discriminatory actions.
- **Permits.** Applications for both state and local government permits should be processed in a timely and fair manner to ensure predictability.
- **Natural Resource Industries.** Maintain and enhance natural resource-based industries, including productive timber, agricultural, and fisheries industries. Encourage the conservation of productive forestlands and productive agricultural lands and discourage incompatible uses.
- **Open Space and Recreation.** Retain open space, enhance recreational opportunities, conserve fish and wildlife habitat, increase access to natural resource lands and water, and develop parks and recreation facilities.
- **Environment.** Protect the environment and enhance the state's high quality of life, including air and water quality, and the availability of water.
- **Citizen Participation and Coordination.** Encourage the involvement of citizens in the planning process and ensure coordination between communities and jurisdictions to reconcile conflicts.
- **Public Facilities and Services.** Ensure that those public facilities and services necessary to support development are adequate to serve the development at the time the development is available for occupancy and use without decreasing current service levels below locally established minimum standards.

- **Historic Preservation.** Identify and encourage the preservation of lands, sites, and structures that have historical or archaeological significance.
- **Climate Change and Resiliency.** Ensure that comprehensive plans, development regulations, and regional policies, plans, and strategies adapt to and mitigate the effects of a changing climate.
- **Shorelines of the State.** The goals and policies of the Shoreline Management Act are set forth in RCW 90.58.020.

PUGET SOUND VISION 2050

PSRC adopted VISION 2050 in 2020 to guide growth and investment in the four-county Central Puget Sound region, including King, Kitsap, Pierce, and Snohomish counties and their cities. It includes multicounty planning policies and a Regional Growth Center (RGC) Strategy that sorts communities into categories based on their roles in the region now or in the future.

PSRC's VISION 2050 identifies the City of Auburn Downtown Subarea as a RGC, type of urban growth area, intended to accommodate a significant share of future growth. PSRC uses "activity units" to measure the density of development and potential for growth within the RGC framework.[1] An *activity unit* is one person or one job. RGCs and other types of centers are eligible as "*priority areas for PSRC's federal transportation funding*" and support PSRC's "*objective of encouraging development of compact, livable centers as an opportunity to accommodate a significant portion of the region's growth.*"[2]

Regional Growth Center (RGC) Requirements

PSRC's requirements for Urban Growth Centers:

- Minimum **18 activity units per acre** existing density.
- Minimum **45 activity units per acre** planned density.
- Size between **200** and **640 acres.**
- Minimum mix of **15 percent** residential and employment activity.

[1] Puget Sound Regional Council. "Regional Centers Framework Update." March 22, 2018. https://www.psrc.org/media/3038.

[2] Puget Sound Regional Council. "Regional Centers Framework Update." 2018.

COMPREHENSIVE PLAN

Starting in summer 2022, the City of Auburn embarked on a major update to its Comprehensive Plan, last updated in 2015. This process is running concurrent to the analysis and planning work done for the 2024 Auburn Downtown Subarea Plan Update. The City coordinated the two planning efforts, and the Downtown Plan Update is central to helping the City meet the Comprehensive Plan's 2044 growth targets. The following land use and economic development goals, policies, and descriptions are quoted from Imagine Auburn: City of Auburn Comprehensive Plan adopted in 2015, which was the current adopted plan at the time of the release of this Draft EIS.[3] The 2024 Periodic Comprehensive Plan is being amended with consideration for current growth trends as well as findings and analysis from the 2024 Auburn Downtown Subarea Plan Update. Any proposed changes will follow all City Code, ordinance, and processes needed.

Land Use

Goals

The following is quoted from Imagine Auburn: 2015 City of Auburn Comprehensive Plan:

- **Character:** Buildings and developments are planned and constructed using innovative architectural and site layout techniques that emphasize social interaction and safety.
- **Wellness:** Residential, commercial, and recreational areas of the City are joined by a system of trails and paths to lessen reliance upon the use of vehicles.
- **Economy:** A robust mix of uses and options makes living, working, and shopping in Auburn desirable.

[3] City of Auburn. "Imagine Auburn: City of Auburn Comprehensive Plan." 2015. https://www.auburnwa.gov/city_hall/community_development/zoning_land_use/auburn_s_comprehensive_plan.

- **Celebration:** Neighborhoods and districts have been identified and are distinguishable through the use of signs, marketing materials, and subarea plans.
- **Environment:** Our rivers, streams, wetlands, habitats, and other natural resources are identified, preserved, and protected for future generations.
- **Sustainability:** Land use activities and developments incorporate low-impact development, energy efficient buildings, crime prevention through environmental design and other sustainable development practices.

Policies

The following is quoted from Imagine Auburn: 2015 City of Auburn Comprehensive Plan:

1. Require building design standards for multifamily, mixed-use, and nonresidential structures to ensure unique and high-quality architectural forms, shapes, and materials.
2. Require site design standards for multifamily, mixed-use, commercial, and residential development proposals that provide connectivity between and through sites, adequate public gathering spaces, sustainable development practices, and efficient provision of utilities and streets.
3. Engage in strategic planning of identified corridors and gateways that includes an emphasized level of planning, designing, improving, regulating, and maintaining those areas providing the most visible impression of Auburn.
4. Delineate neighborhoods and districts, and develop strategies for creating greater neighborhood identity that reinforces the concept of "One Auburn."
6. Develop downtown Auburn into a safe, walkable community with attractive public plazas and buildings and an engaging streetscape through planning, regulation, and capital improvements.

7. Support and promote efforts that create or expand population and employment opportunities within downtown Auburn.
8. Identify, protect, preserve, and restore Auburn's environment and natural resources.
9. Implement measures to promote buildings that conserve energy and water and reduce greenhouse gas emissions.
10. Develop vehicular gateways that provide access to Auburn into well-signed, attractive, and prominent entry points.
12. Establish parking standards that limit the overall number of spaces, allowing for landscaping and site layout to soften the visual impact of large parking lots.
13. Create incentives for good community design by allowing increased height, density, intensity, and other standards.
14. Ensure harmonious transition between land uses and zoning designations through the use of setbacks, vegetation, building orientation, and architectural design.
15. Employ "crime prevention through environmental design" when designing communities and development proposals.

Economic Development

Goals

The following is quoted from Imagine Auburn: City of Auburn Comprehensive Plan:

- **Character:** Our cultural diversity has been leveraged to bind our community, expand our market, and celebrate cultural traditions.
- **Wellness:** We are a safe community with walkable commercial districts, where both the perception and the reality are that crime activity is low and public safety staffing meets or exceeds community expectations.

- **Service:** Our economic development strategies focus on supporting the existing business community; as a result, recruitment is minimal because businesses desire to locate here.
- **Economy:** We are able to measure and achieve defined targets for manufacturing, service, and retail jobs and revenues.
- **Celebration:** We actively promote our local businesses and have been successful at making our residents more aware of what is available locally as well as attracting visitors from beyond our City.
- **Environment:** Our economy is growing and diversifying because of our efforts to protect our rivers, streams, wetlands, and other environmental resources.
- **Sustainability:** Residents are staying in Auburn to work and shop, and we are widely considered to be a regional dining, shopping, and entertainment destination.

Policies

The following is quoted from Imagine Auburn: City of Auburn Comprehensive Plan:

1. Attract high-wage employment opportunities and sales-tax-generating businesses to diversify the City's economic base and generate positive secondary benefits for the community.
3. Dedicate resources to pursue an expanded economic development program for the City.
5. Create an economic development toolbox comprising programs and incentives to reduce financial, regulatory, and operational constraints for existing or new business growth and expansion.
6. Prioritize the installation of key infrastructure at identified employment areas to facilitate development of these economic centers.

HOUSING ACTION PLAN

The City recently completed a Housing Action Plan that includes several planning objectives relevant to downtown and the study area:[4]

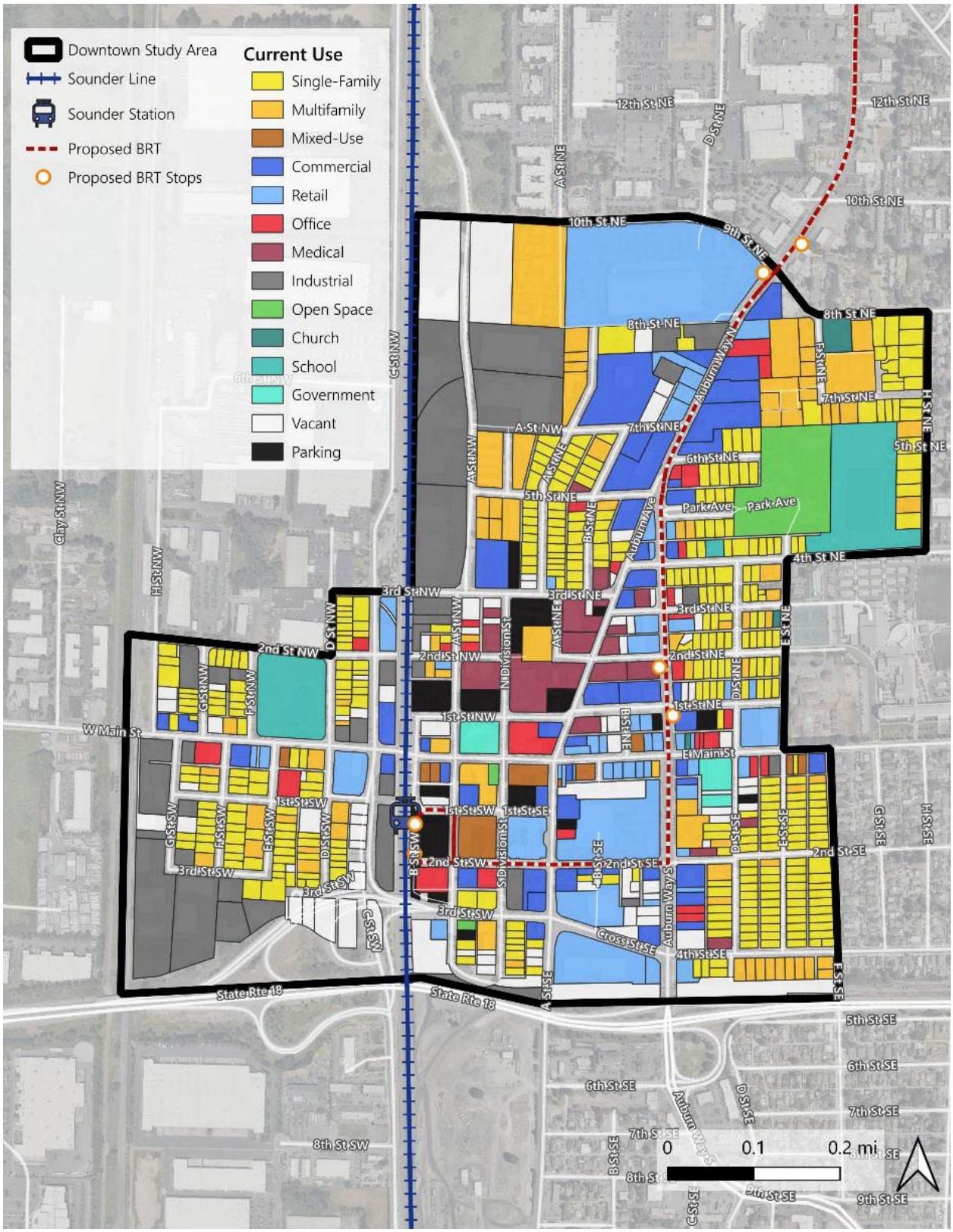
- Encourage market rate development downtown.
- Encourage affordable housing downtown.
- Encourage missing middle housing in R-7 zones.
- Prevent displacement and encourage the preservation of existing affordable housing.

3.1.2 Current Land Use Patterns and Zoning

LAND USES WITHIN THE STUDY AREA

Figure 3-1 shows the current land uses in the study area, as reported by the King County Assessor. Single-family residential development is clustered in the eastern and western areas, with more multifamily development in the northern area. Retail and commercial uses are along Auburn Way and Main Street, with a cluster of medical uses in the central area. There are also numerous parking lots in the central core, as well as industrial uses along the railroad tracks and in the far southwest of the study area. Table 3-1 details acreage for current land uses.

[4] City of Auburn. "Housing Action Plan" https://speakupauburn.org/hap#:~:text=The%20City's%20Community%20Development%20Department,Action%20Plan%20by%20June%202021.



SOURCES: King County Assessor, Leland Consulting Group, 2022

FIGURE 3-1 Current Uses in Study Area

TABLE 3-1 Current Land Use within the Study Area

Use	Acres (Gross)	Share
Single-Family	53.0	17%
Multifamily	30.8	10%
Mixed-Use	3.4	1%
Commercial	24.1	8%
Retail	37.9	12%
Office	7.0	2%
Medical	8.7	3%
Industrial	48.9	16%
Open Space	8.0	3%
Church	1.1	0%
School	37.1	12%
Government	2.3	1%
Vacant	39.4	13%
Parking	7.7	2%
Total Parcel Acreage	**309.1**	**100%**

SOURCES: King County Assessor, Leland Consulting Group, and MAKERS 2022

ADJACENT LAND USES

Land uses adjacent to the study area include a mix of multifamily and single-family uses to the northeast and predominantly single-family uses to the east and south of SR 18, which is the southern boundary of the study area. Industrial land uses are typical in areas west of the study area. North of the study is a mix of commercial and industrial uses, including the Auburn Municipal Airport, a General Aviation[5] field located about one-third of a mile north of 15th Street NE. The airport does not support commercial passenger service but does

[5] The Federal Aviation Administration defines General Aviation airports as "*public-use airports that do not have schedule service, or have less than 2,500 annual passenger boardings.*" Airport Categories. Federal Aviation Administration. Accessed February 26, 2024. https://www.faa.gov/airports/planning_capacity/categories

serve civilian flying aircraft. Typical aircraft include fixed-wing and helicopters that seat six or fewer passengers, and provide a range of functions, including medevac, law enforcement, training, recreational, charter, and business operations. The airport sees an average of 450 take-offs/landings per day (estimated at 140,000 annually).[6]

The City of Auburn is currently updating its 2024 City of Auburn Comprehensive Plan and exploring land use changes outside of the boundaries of downtown. The City is coordinating these two processes to ensure that City-wide changes reflect the vision for downtown.

ZONING

The study area includes a diverse mix of existing zones, including light industrial, auto-oriented commercial areas, the mixed-use, pedestrian-oriented Downtown Urban Center (DUC) zone, and residential areas that are predominatnly single-family houses. Table 3-2 provides an overview of zones wihtin the study area.

Figure 3-2 illustrates the distribution of the existing zones across the subarea, including how the Airport Overlay Zones impact the study area. No conflicts with building height limits required by Auburn City Code (ACC) 18.38.070 are expected given the distance between the runway and the study area. ACC Chapter 18.38 requires development standards and prohibits the following uses in the Inner Safety Zone: multiple-family dwellings, mixed-use development, senior housing, assisted living/nursing homes, supportive housing, hospitals, schools and day care centers, single-family dwellings, and other uses, similar to those above, that could interfere with airport operations.

[6] Community Impact Auburn Airport-City of Auburn. Accessed February 26, 2024. https://auburnmunicipalairport.com/community-impact.

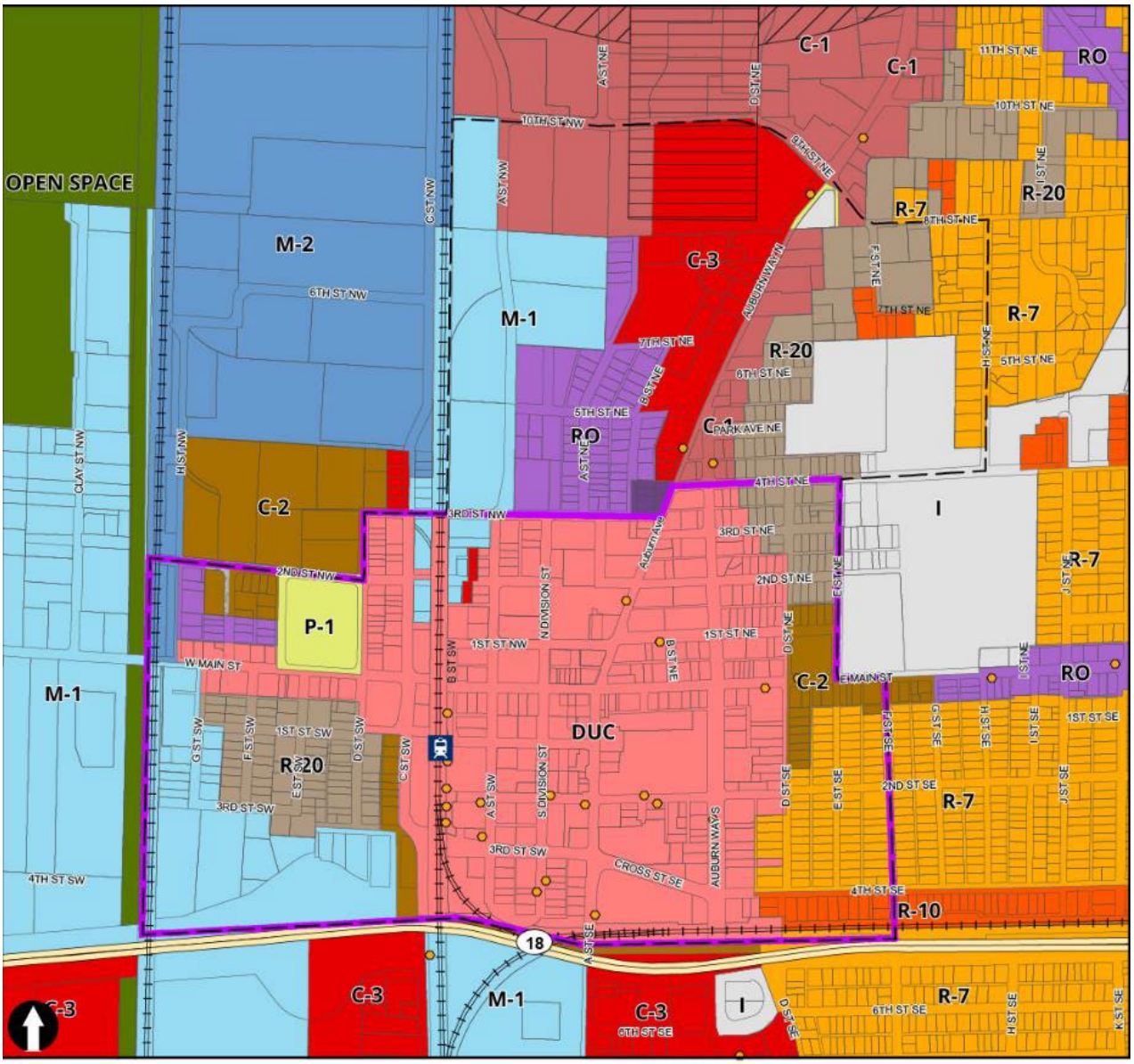
TABLE 3-2 Existing Zones: Acreage, Building Heights, and Density

	Zone	Maximum Height	Maximum Density Units/Acre	Acres
COMMERCIAL ZONES	Downtown Urban Center – DUC	75 feet	Approx 170[a]	133.13
	Light Commercial District – C1	45 feet	N/A	23.4
	Central Business District – C2	60 feet[b]		11.9
	Heavy Commercial District – C3	75 feet	36	29.09
RESIDENTIAL ZONES	Residential – R7	35 feet	7	24.46
	Residential – R10	45 feet	10	5.61
	Residential – R20	50 feet	20	39.04
	Residential Office District – RO	35 feet	12	23.41
	Residential Office District (Hospital) RO-H	65 feet	12	1.04
INDUSTRIAL ZONES	Light Industrial District – M1	45 feet	No limit	58.79
	Heavy Industrial District – M2	45 feet	Not allowed	2.29

SOURCES: Auburn City Code, Title 18 Zoning, MAKERS

a. Maximum Floor Area Ratio for residential is 4.0 with bonuses, which are provided for amenities such as public plazas, daycare, and underground parking.

b. No greater than adjacent street right-of-way width, typically 60 feet.



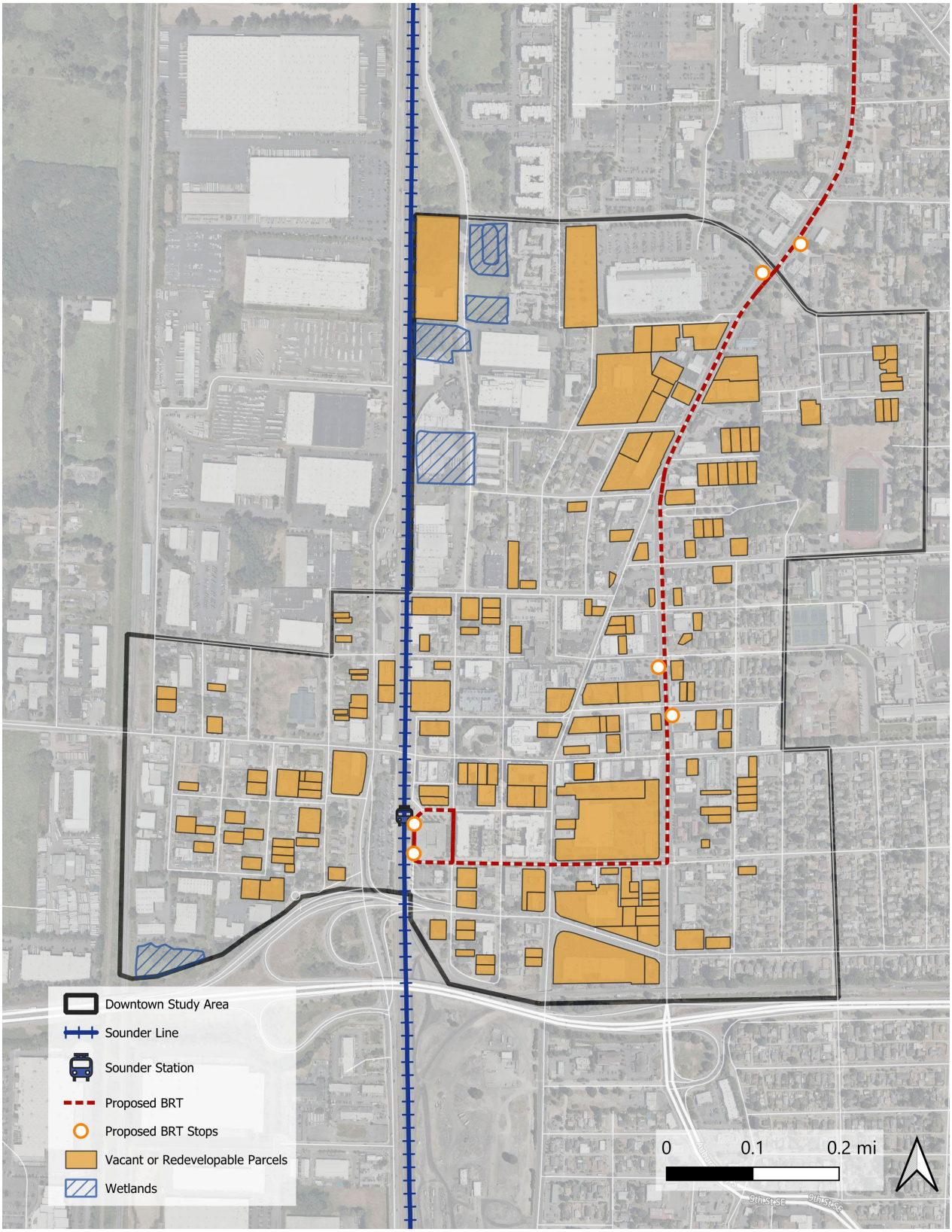
SOURCES: City of Auburn GIS data, MAKERS

FIGURE 3-2 Existing Zoning and Airport Overlay

LAND CAPACITY

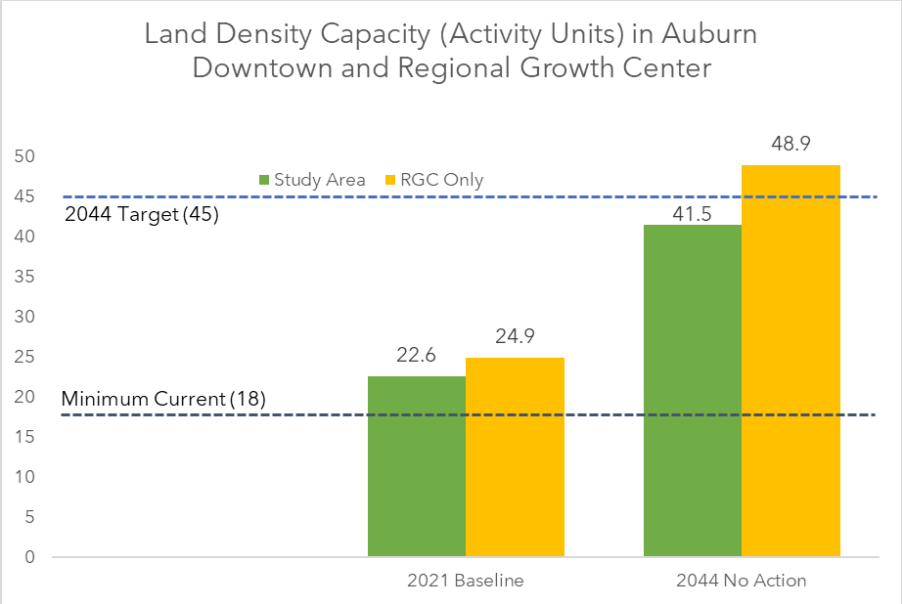
Figure 3-3 shows the vacant and redevelopable parcels used in this analysis. These parcels include those classified as vacant or redevelopable by the King County Buildable Lands Report as well as parcels with an improvement-to-land value ratio of 1.0 or less, a common threshold for redevelopment. Several parcels with proposed or planned development or known potential were added to the list in consultation with City staff as well.

Figure 3-4 shows the activity unit density requirements, baseline conditions, and no action projections for the downtown study area and the RGC. Assuming redevelopment on the parcels shown above consistent with past and projected future market trends, the RGC is expected to exceed PSRC's density targets by 2044, although the downtown study area as a whole falls slightly short of the required densities. However, note that changes in market trends may affect the acreage that redevelops over the next 20 years to the point where the target could be met even under a No Action scenario.



SOURCES: Leland Consulting Group, City of Auburn

FIGURE 3-3 Vacant and Redevelopable Parcels in the Study Area



SOURCES: Leland Consulting Group, King County, PSRC

FIGURE 3-4 **Downtown Land Capacity**

MARKET CONDITIONS

The market conditions for the City of Auburn are informed by an economic study conducted during the Downtown Planning Process. Key findings from the market study are summarized below.

Demographics, Housing, and Employment

- Auburn's population has grown significantly since the 1980s. PSRC forecasts a population increase of about 20 percent for the next two decades in Auburn.[7]
- The current population of the downtown study area is significantly older than the citywide population, and the study area contains a number of large senior housing developments.
- About a quarter of downtown housing units in the study area are single-family homes, and a third of housing units are in large developments of 50 units or more.

[7] Puget Sound Regional Council, Land Use Vision – Implemented Targets. May 2023. https://www.psrc.org/our-work/projections-cities-and-other-places.

- The downtown study area population is classified by PSRC as having a higher risk of displacement due to redevelopment.[8]
- Auburn is historically a "blue-collar" city and the majority of jobs and job growth in the past 20 years has been in manufacturing, although relatively few of these jobs are in the downtown area. The downtown area accounts for around 9 percent of all jobs in the City.
- Retail jobs make up the largest share of jobs in the study area, at 21.6 percent. The health care sector accounts for another 20.5 percent of downtown jobs, and MultiCare is the largest employer in the study area, with 635 employees.
- Most employees in downtown Auburn do not live in the downtown area.

Market Outlook

- Most recent development in downtown Auburn has taken place within a small part of the downtown core, and the majority of the development consisted of developing housing over ground-floor commercial space.
- Although the average asking monthly apartment rent in Auburn is among the lowest in the Seattle area, rents have increased by 7.3 percent over the past year, decreasing the gap between Auburn and Seattle metro area rents.
- Auburn has seen considerably more office development than other Central Puget Sound municipalities in recent decades, anchored in health care and public sectors.
- Although information and technology jobs are growing the fastest, health care and government are both expected to add significant numbers of jobs regionally in the coming years. Auburn's existing cluster of medical facilities makes the downtown area well positioned to take advantage of this regional trend.

[8] Puget Sound Regional Council, Displacement Risk Interactive Ma, Accessed February 23, 2024, https://psregcncl.maps.arcgis.com/apps/webappviewer/index.html?id=4e1f07c343534e499d70f1686171d843.

3.1.3 Urban Form

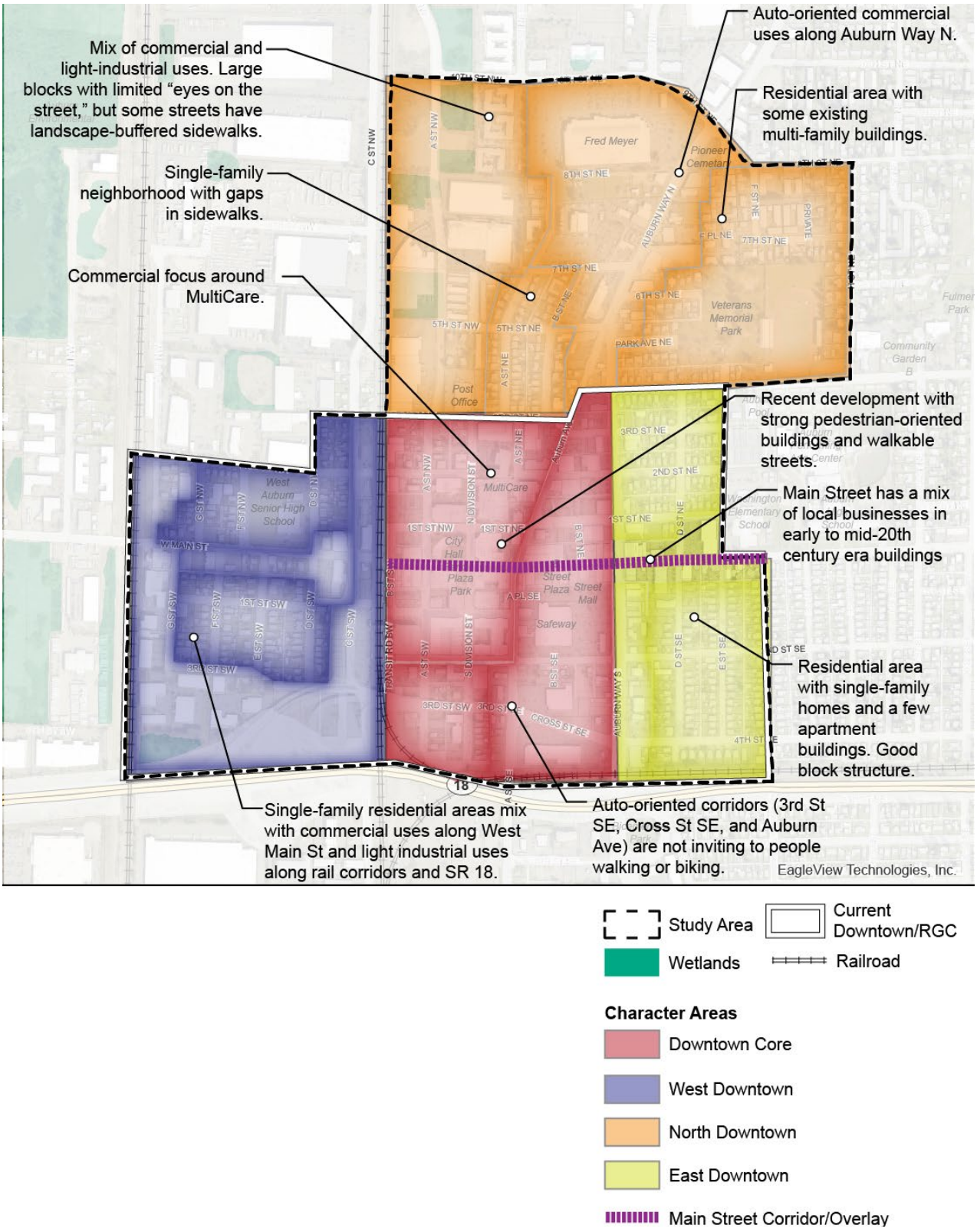
Urban form within the subarea shows significant diversity within a small geographic area. Industrial areas along the rail corridors reflect Auburn's industrial and agricultural heritage. Early and mid-20th century buildings within the downtown core and along the W/E Main Street corridor integrate with more recent, dense urban development at the heart of the DUC. Public plazas, walkable streets, and permeable ground floors further contribute to the pedestrian-oriented DUC area.

Auto-oriented commercial areas, particularly along arterials, support a range of commercial uses, but also create circulation challenges for people walking, biking, and accessing transit through the area. The office and medical hub around MultiCare feels distinct from the surrounding areas and could offer more development opportunities.

Residential areas include single-family neighborhoods east of Auburn Way S and some multifamily complexes east of Auburn Avenue. Veterans Memorial Park is key amenity for the area north of downtown, providing green space and recreational opportunities.

DOWNTOWN CHARACTER AREAS

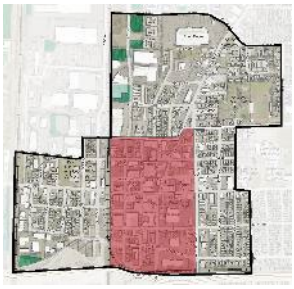
To better understand current conditions within the subarea and analyze future opportunities, the subarea was divided into four character areas: downtown core, west downtown, north downtown, and east downtown (**Figure 3-5**). The Main Street corridor through downtown was also analyzed, given the unique mix of existing businesses in this area. The current conditions of each of these existing areas within downtown were assessed. The character areas identified in the map informed the early analysis conducted for the Downtown Plan Update; however, the plan's recommendations build on this framework to propose more detailed changes in land use and transportation.



SOURCE: MAKERS

FIGURE 3-5 Built Environment of Study Area's Existing Character Areas

Downtown Core



The downtown core area was the primary focus of the 2001 Downtown Plan and has seen significant public and private investment over the last two decades. These investments have resulted in a strong pedestrian environment, with streetscapes that are accessible, support needs of adjacent uses, and invite people to walk. The curbless design along a portion of S Division Street is a key investment that supports a pedestrian-oriented downtown core area that could be used for festivals or other public events. Public plazas within the downtown core area further support the pedestrian environment.

The downtown core area also retains some two- and three-story older buildings, reflecting the historic built form of downtown Auburn, which grew rapidly around the turn of the last century. These buildings are primarily located along the Main Street corridor, but they are also present in other areas within the downtown core.

A mix of new and historic pedestrian-oriented building types and successful implementation of pedestrian-friendly street design has created a walkable urban form in many parts of the downtown core. See Figure 3-5 for a map of character areas within the study area.



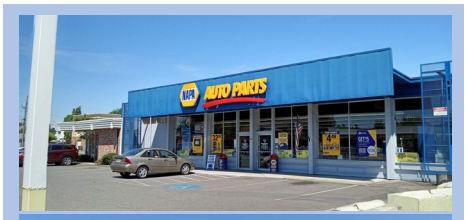
Images of the Downtown Core.
SOURCE: MAKERS

MultiCare Hub

MultiCare, located west of Auburn Avenue between 1st Street NE and 3rd Street NE, is a major employer and destination that anchors the northern end of the downtown core area. MultiCare plans to expand within existing parking areas of the site. Sound Transit also has plans to build a new parking garage structure in this area.



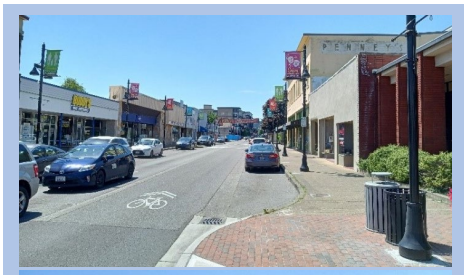
MultiCare
SOURCE: City of Auburn





Examples of auto-oriented commercial space and use that are common in parts of the study area

SOURCE: MAKERS





Images of Main Street



Postmark Center for the Arts

SOURCE: MAKERS

Auto-Oriented Commercial

Some auto-oriented commercial uses remain in the downtown core, such as along the corridors of 3rd Street SE, Cross Street SE, and Auburn Way S. The Safeway grocery store, an important community asset for downtown, has a large surface parking lot that could present future infill development opportunities. The east–west alignment of the Safeway site and the Sounder station and pedestrian plaza could offer a strong multimodal connection within downtown.

Industrial

There are also a few industrial commercial uses in the downtown core area west of A Street NW and north of 1st Street NW, along the BNSF/Sounder railroad corridor. These include warehouses, surface parking lots, and outdoor storage to support commercial activities.

Main Street Corridor/Overlay



Once one of the principal shopping destinations in the valley, Main Street retains a mid-20th century style, with single-story commercial buildings and small businesses lining the street. The commercial area engages pedestrians with small-scale storefronts, multiple windows and clear sidewalks, pedestrian lighting, and public art. The commercial street is home to a diverse mix of small and local businesses, many of which have multilingual signage and serve Auburn and South King County residents from diverse cultures and ethnic backgrounds. It crosses both the downtown core and the east downtown character areas.

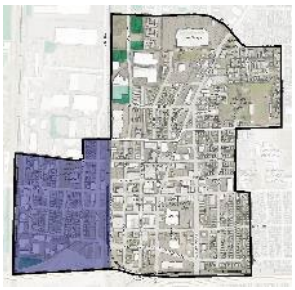
A few two- and three-story early 20th century buildings along W Main Street (west of N Division Street) connect to the history of downtown and include ground-floor uses that activate the corridor. Many of the buildings along E Main Street (east of N Division Street)

retain the mid-century architectural style of a commercial street, with small department stores and shops mixing with office and civic buildings. The aging buildings in this area also reflect a range of conditions—some have been updated while others may require increased maintenance or renovation to continue to support existing or new commercial uses.

Sidewalk improvements along portions of E Main Street also contribute to an inviting and comfortable pedestrian environment. Street parking buffers pedestrians from vehicle traffic in these areas, but as pedestrian volumes increase, these parking spaces could become opportunities to expand pedestrian space.

The new Postmark Center for the Arts provides an arts and cultural hub between the downtown core area and east downtown and Main Street.

West Downtown



The west downtown area is located west of the BNSF/Sounder railroad corridor and C Street NW arterial and east of the Union Pacific railroad corridor. The intersection of E Main Street and B Street NW is one of the key vehicle gateways into the downtown core area, and there are opportunities to better connect west downtown and the downtown core via user experience enhancements (such as more cohesive development, the clarification of pedestrian and bike pathways, and similar public realm enhancements). The intersection is also challenging for people with limited mobility. The Auburn Station pedestrian overpass that is located to the south of W Main Street crosses only the railroad corridor, requiring some people with limited mobility who cannot cross the tracks at grade to travel out of their way to get to west downtown. (See Chapter 4, *Transportation*, for more information on multimodal access in the study area.)



Images of west downtown

SOURCE: MAKERS

W Main Street Commercial Uses

W Main Street features a mix of commercial uses, some located in formerly residential buildings, including several small, locally owned businesses. The W Main Street corridor has sidewalks and some public art, but intermittent parking areas and differing setback patterns along the corridor fail to provide strong definition to the space.

Residential/Industrial Mix

North and south of Main Street, west downtown has a small grid of streets, with inconsistently sized block featuring an eclectic mix of residential, commercial, and light industrial uses. West Auburn Senior High School, a technical high school alternative for Auburn students, anchors the area. A mostly residential neighborhood surrounds the school, comprising older single-family houses and some apartment buildings, particularly south of Main Street.

The street grid in the area is somewhat irregular, with smaller blocks and parcels along W Main Street, and larger blocks (a few with alleys) and larger parcels to the north and south. Industrial uses are most common at the extreme north and south of the area, with larger, more recently constructed warehouses and flexible business parks.

North Downtown



Unlike other parts of downtown, the area north of 3rd Street NE was developed after World War II and has historically been somewhat separate from downtown Auburn. It has a more-auto-oriented built form and less-complete street grid, but the area could present opportunities for future redevelopment and infill residential. This area has the most diverse mix of uses and existing building styles within the study area.

Commercial Corridors

Auburn Way N and A Street NW are key arterials through this area, creating some divisions and distinctions between uses. Commercial uses predominate along both the Auburn Avenue and the Auburn Way N corridors, which are flanked by residential areas on both sides. Fred Meyer is the existing commercial anchor at the northern edge.

Industrial Uses and Business Parks

On the western edge, industrial uses similar to those in the downtown core area extend from the BNSF railroad corridor east to A Street NW (and to A Street NE in some areas).

Residential Pockets

Pockets of single-family residential located between 3rd Street NW/NE and 7th Street NE have a smaller street grid than the downtown core or and industrial portions of the study area. The presence of alleys in residential street grid areas both east and west of Auburn Avenue provide good site access, creating the opportunity for infill housing.

East of the Auburn Way corridor is a mixed residential area with single-family and multifamily housing. The area has limited internal street connectivity, with many small private roads and driveways. Veterans Memorial Park is a key open space and cultural asset in this area. The boulevard style of the Park Avenue entrance, with the alley of mature existing trees, is unique and adds green infrastructure to the area. This area is also close to Auburn High School and the Auburn Performing Arts Center and is a key community destination in Auburn.

East Downtown

Residential Surroundings



Residential homes in the east downtown area

SOURCE: MAKERS



North and south of E Main Street is a single-family residential neighborhood with a well-connected street grid of blocks approximately 350 by 600 feet and pre–World War II houses on small lots. The neighborhood is within close and easy walking distance of E Main Street businesses and the downtown core area. There are also a few multifamily developments along Auburn Way S.

3.2 Potential Impacts

3.2.1 Thresholds of Significance

Thresholds of significance are used to define impacts that would have adverse impacts prior to or without any mitigation. The alternatives are expected to result in a land use impact if:

- **Regional and local policy consistency.** Development that is inconsistent with state or regional growth management policies or the City's current plans and policies could have adverse effects without mitigation.
- **Use compatibility.** Changes in land use patterns that preclude reasonable transitions between activity levels or create new adjacent uses that are likely to result in incompatibilities.
- **Urban form.** Differences in allowed development types that negatively impact aesthetics and/or the human experience could have adverse impacts without mitigation.
- **Commercial displacement.** Redevelopment could increase displacement risks for existing businesses and commercial uses.

3.2.2 Impacts Common to All Alternatives

SHORT-TERM IMPACTS

Short-term impacts can also result from construction activities, which can include an increase in traffic, and air and noise pollution. These impacts can be mitigated by adherence to the mitigation measures required by the permitting jurisdiction (City, county, and/or state agency) and through construction site inspections as required by a project's construction permits. No significant adverse impacts on land use are expected from construction.

REGIONAL AND LOCAL POLICY CONSISTENCY

Growth Management Act

The 2001 Auburn Downtown Plan and EIS has been a central part of the City of Auburn's Comprehensive Plan vision for over twenty years, resulting in a strong and vibrant economic center for the greater community. The Downtown Plan Update builds on this previous vision to ensure continued opportunities for growth and strong alignment with current local and regional policies. This Table 3-4 provides an overview of how three alternatives support relevant the goals of the GMA.

TABLE 3-3 Consistency with Growth Management Act

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
GMA GOALS				
Urban Growth. Encourage development in urban areas where adequate public facilities and services exist or can be provided in an efficient manner.	◐	●	●	All alternatives promote urban growth, but alternatives 2 and 3 provide more development opportunities by expanding the downtown area and pursuing zoning changes.
Reduce Sprawl. Reduce the inappropriate conversion of undeveloped land into sprawling, low-density development.	◐	●	●	By promoting growth opportunities downtown, all alternatives promote reduce sprawl. Alternatives 2 and 3 provide more development opportunities by expanding the downtown area and pursuing zoning changes.
Transportation. Encourage efficient multimodal transportation systems that are based on regional priorities and coordinated with county and city comprehensive plans.	◐	●	●	All alternatives accommodate future growth around the City's existing transportation resources. Alternatives 2 and 3 provide more transit-oriented development capacity by expanding the downtown area to align with new frequent bus service. See Transportation Chapter for more details
Housing. Encourage the availability of affordable housing to all economic segments of the population of the state, promote a variety of residential densities and housing types, and encourage preservation of existing housing stock.	○	◐	●	All alternatives at least partially encourage the affordability of housing by increasing capacity for population growth downtown. Alternatives 2 provide moderate growth and Alternative 3 provide the most robust growth opportunities.
Economic Development. Encourage economic development throughout the state that is consistent with adopted comprehensive plans; promote economic opportunity for all citizens of this state, especially for unemployed and for disadvantaged persons; promote the retention and expansion of existing businesses and recruitment of new businesses; recognize regional differences impacting economic development opportunities; and encourage growth in areas experiencing insufficient economic growth, all within the capacities of the state's natural resources, public services, and public facilities.	◐	●	●	All alternatives would accommodate future growth for both population and jobs. Alternatives 2 and 3 provide more robust economic development benefits by expanding the downtown area, increasing new opportunities for homes and new jobs. This DEIS also studies the potential for commercial displacement under the action alternatives

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
GMA GOALS (CONTINUED)				
Property Rights. Private property shall not be taken for public use without just compensation having been made. The property rights of landowners shall be protected from arbitrary and discriminatory actions.	●	●	●	All alternatives of the Downtown Plan Update support the GMA goal of not taking private property for public use without just compensation.
Open Space and Recreation. Retain open space, enhance recreational opportunities, conserve fish and wildlife habitat, increase access to natural resource lands and water, and develop parks and recreation facilities.	◐	◐	◐	All alternatives support the Downtown Plan Update goals of providing new green space, and increasing access to existing open space resources. In the area
Environment. Protect the environment and enhance the state's high quality of life, including air and water quality, and the availability of water.	◐	◐	◐	Future redevelopment of Downtown under all of the alternatives will have beneficial impacts on the environment by meeting current building, energy, and stormwater codes.
Citizen Participation and Coordination. Encourage the involvement of citizens in the planning process and ensure coordination between communities and jurisdictions to reconcile conflicts.	◐	◐	◐	Community engagement has occurred at key stages during the development of the Downtown Plan Update, and will continue through the EIS process.
Climate Change and Resiliency. Ensure that comprehensive plans, development regulations, and regional policies, plans, and strategies adapt to and mitigate the effects of a changing climate.	◐	●	●	All alternatives would help mitigate climate change by increasing opportunities for transit-oriented development (TOD). Alternatives 2 and 3 provide the most robust TOD opportunities.

PSRC VISION 2050

The City of Auburn, designated as a Core City in PSRC's VISION 2050, is "*intended to accommodate a significant share of future growth*" in population and employment. **Table 3-4** identifies pertinent land use goals and policies and how well the three alternatives would address them within downtown. Alternative 1, No Action, is consistent with VISION 2050 goals, but the development alternatives would more optimally meet goals for increasing density and providing housing and supporting transit (see **Table 3-4**).

TABLE 3-4 Consistency with VISION 2050 Multicounty Planning Goals and Policies

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
REGIONAL GROWTH GOAL AND STRATEGIES				
Regional Growth Goal: The region accommodates growth in urban areas, focused in designated centers and near transit stations, to create healthy, equitable, and vibrant communities well-served by infrastructure and services. Rural and resource lands continue to be vital parts of the region that retain important cultural, economic, and rural lifestyle opportunities over the long term.	◐	●	●	Alternatives focus residential and job growth within downtown, which is well served by infrastructure and services. The development alternatives provide growth where future high-capacity transit is planned along the Auburn Way N corridor.
MPP-RGS-6 Encourage efficient use of urban land by optimizing the development potential of existing urban lands and increasing density in the urban growth area in locations consistent with the Regional Growth Strategy.	◐	●	●	Development alternatives would rezone land, enabling denser urban development, and align zoning to current market feasibility in order to promote near-term redevelopment.
MPP-RGS-9 Focus a significant share of population and employment growth in designated regional growth centers.	◐	●	●	All alternatives accommodate future growth in the RGC. The development alternatives provide more development opportunities by expanding the downtown area and pursuing zoning changes.
ENVIRONMENTAL GOAL				
Environmental Goal: The region cares for the natural environment by protecting and restoring natural systems, conserving habitat, improving water quality, and reducing air pollutants. The health of all residents and the economy is connected to the health of the environment. Planning at all levels considers the impacts of land use, development, and transportation on the ecosystem.	◐	●	●	All alternatives would implement City critical area regulations. Development alternatives would create greater opportunities for transit-oriented development, and promote multimodal circulation and energy-efficient buildings that reduce environmental impacts.
DEVELOPMENT PATTERN GOAL AND STRATEGIES				
Development Pattern Goal: The region creates healthy, walkable, compact, and equitable transit-oriented communities that maintain unique character and local culture, while conserving rural areas and creating and preserving open space and natural areas.	◐	●	●	All alternatives would promote compact, walkable development within the downtown area. The development alternatives expand transit-oriented development opportunities that promote healthy, walkable communities.

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
MPP-DP-1 Develop high-quality, compact urban communities throughout the region's urban growth area that impart a sense of place, preserve local character, provide for mixed uses and choices in housing types, and encourage walking, bicycling, and transit use.	◐	●	●	Development alternatives expand the footprint of downtown Auburn while highlighting the unique character areas within the subarea and improving multimodal circulation.
HOUSING GOAL AND STRATEGIES				
Housing Goal: The region preserves, improves, and expands its housing stock to provide a range of affordable, accessible, healthy, and safe housing choices to every resident. The region continues to promote fair and equal access to housing for all people.	○	●	●	
MPP-H-2 Provide a range of housing types and choices to meet the housing needs of all income levels and demographic groups within the region.	○	●	●	Development alternatives expand opportunities to develop housing to more parts of the study area with zoning that encourages infill in different types of built-up areas.
MPP-H-7 Expand the supply and range of housing at densities to maximize the benefits of transit investments, including affordable units, in growth centers and station areas throughout the region.	○	●	●	
ECONOMIC GOAL AND POLICIES				
Economic Development Goal: The region has a prospering and sustainable regional economy by supporting businesses and job creation, investing in all people and their health, sustaining environmental quality, and creating great central places, diverse communities, and high quality of life.	○	◐	◐	Development alternatives promote a compact urban center, developed around transit resources, that will create a vibrant center for people to work and live.
MPP-Ec-1 Support economic development activities that help to recruit, retain, expand, or diversify the region's businesses, targeted towards businesses that provide living-wage jobs.	○	●	●	Development alternatives promote new job opportunities and encourage a diversity of job types.
MPP-Ec-12 Identify potential physical, economic, and cultural displacement of existing businesses that may result from redevelopment and market pressure. Use a range of strategies to mitigate displacement impacts to the extent feasible.	○	◐	◐	Development alternatives promote economic development by expanding commercial and mixed-use spaces downtown, increasing population by adding housing and encouraging a range of new commercial spaces.

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
VISION 2050 ACTIONS - LOCAL POLICIES AND ACTIONS TO ADDRESS CLIMATE CHANGE				
CC-Action 3 Cities and counties will incorporate emissions reduction policies and actions that contribute meaningfully toward regional greenhouse gas emission goals, along with equitable climate resiliency measures, in their comprehensive planning. Strategies include land uses that reduce vehicle miles traveled and promote transit, biking, and walking consistent with the Regional Growth Strategy, developing and implementing climate-friendly building codes, investments in multimodal transportation choices, and steps to encourage a transition to cleaner transportation and energy systems.	◐	●	●	Development alternatives will help Auburn meet climate change goals by increasing both housing options and jobs close to transit. Redevelopment will also provide streetscape improvement opportunities that enhance multimodal circulation. New buildings that meet current building codes will lower the use of fossil fuels in the City.

SOURCES: PSRC, VISION 2050 Multicounty Planning Policies, https://www.psrc.org/media/1695
PSRC, VISION 2050 Actions, https://www.psrc.org/media/1696

Comprehensive Plan

Table 3-5 provides an overview for how the alternatives align with the key goals of the City's 2015 Comprehensive Plan.

TABLE 3-5 **Consistency with Comprehensive Plan**

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
LAND USE VALUES				
Character: Residential neighborhoods will include amenities, features, and layouts that promote interaction amongst residents.	◐	●	●	Development alternatives will promote mixed-use development that is compatible with residential uses.
Wellness: The design of residential neighborhoods will emphasize safety and non-motorized connectivity	○	●	●	Development alternatives include some improvements to non-motorized mobility.
Economy: Neighborhoods have a physical and personal connection to Auburn's commercial centers and attractions. People want to move to Auburn because of the commercial and recreational opportunities it has to offer.	◐	●	●	Development alternatives build on the existing downtown plan's successes in making downtown an attractive, lively center. Alternative 2 does the most to encourage arts-related uses through the updated C-2 zone.
Celebration: Districts and neighborhoods are identified, promoted, and celebrated.	◐	●	●	Development alternatives will enhance existing character areas within downtown Auburn.

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
Environment: The built environment will fit into the natural landscape in a way that protects and respects ecosystem function and that preserves native vegetation and soils.	○	◐	◐	Development alternatives will increase the number of new and/or renovated buildings that are energy efficient and environmentally sensitive.
Sustainability: Natural resources, economic prosperity, and cultural vibrancy are balanced in a way that builds and maintains a thriving and long-lasting community.	○	●	●	Development alternatives will continue to promote a compact urban center that provides socially connected, active living opportunities; promotes economic development; and reduces the impact on the surrounding environment.
ECONOMIC DEVELOPMENT VALUES				
Character: Our cultural diversity has been leveraged to bind our community, expand our market, and celebrate cultural traditions.	○	●	◐	Development alternatives will promote Downtown Auburn as a center for local arts and culture.
Wellness: We are a safe community with walkable commercial districts where there the perception and reality are that crime activity is low and public safety staffing meets or exceeds the community's expectations.	○	●	●	Development alternatives will increase activity levels and "eyes on the street," and will promote multimodal circulation.
Economy: We are able to measure and achieve defined targets for manufacturing, service, and retail jobs and revenues.	○	●	●	Development alternatives will increase jobs within downtown Auburn.
Celebration: We actively promote our local businesses and have been successful at making our residents more aware of what is available locally as well as attracting visitors from beyond our City.	○	●	◐	Both development alternatives support businesses by increasing activity within the downtown area. Alternative 2 promotes redevelopment that relates to the existing scale of the Main Street corridor.
Sustainability: Residents are staying in Auburn to work and shop, and we are widely considered a regional dining, shopping, and entertainment destination.	○	●	●	Development alternatives increase and expand activities in the downtown area.

Housing Action Plan

Table 3-6 provides an overview for how the alternatives align with the key goals of the City's 2021 Housing Action Plan.

TABLE 3-6 Consistency with Housing Action Plan

Goal or Policy	Alt 1	Alt 2	Alt 3	Notes
LEGEND: ○ Partially meets ◐ Meets ● Optimally meets				
REGIONAL GROWTH GOAL AND STRATEGIES				
Encourage market rate development downtown	○	●	●	Development alternatives will increase market-rate housing within downtown Auburn.
Encourage affordable housing downtown	○	●	●	Development alternatives will increase the size of the downtown area, increasing opportunities for new affordable housing development.
Encourage missing middle housing in R-7 zones	○	●	●	Development alternatives will increase the types of missing middle housing that is allowed within the City.
Prevent displacement and encourage the preservation of existing affordable housing	◐	◐	◐	Development alternatives increase development capacity in certain areas, but not generally in areas where dense naturally occurring affordable housing is already present.

Regional Growth Center

The current boundary of downtown aligns with the city's existing RGC boundary. The Downtown Plan Update explores different strategies for expanding downtown to increase housing options and increase growth around transit resources. Figure 3-5 illustrates the boundaries of the existing downtown/RGC area, the study area, and the proposed Revised Downtown Area that are studied in the Downtown Plan Update. (See Chapter 2, *Alternatives*, for a description of each of these areas.)

The plan also explores the potential expansion of the RGC boundary to assess the impacts under different growth assumptions.

Not meeting regional growth targets could be considered a significant adverse impact.

No other significant adverse impacts on regional and local policy consistency are expected because the alternatives are consistent with state and regional growth management policies and the City's current plans and policies.

USE COMPATIBILITY

Downtown Auburn currently includes a mix of commercial, mixed-use, residential, and light industrial uses. All of the alternatives include these uses, although in different mixes and intensities. New growth is expected to occur under all of the alternatives, although the amount of growth and composition of the mix of land uses would vary by alternative. Intensity would increase across the proposed Revised Downtown Area with new businesses, residents, and employees. Redevelopment and changes in the intensity of residential, commercial, and mixed-use development in the proposed Revised Downtown Area bring the potential for land use conflicts.

Growth of new commercial hubs and mixed-use nodes along corridors would increase traffic, potentially impacting adjacent residential areas in terms of pedestrian comfort and noise and air pollution, while the impacted population grows in adjacent upzoned residential areas. SR 18 forms the southern boundary of downtown Auburn, and redevelopment adjacent to this route and other major arterials is expected with all of the alternatives. Highways and arterials can be a source of air pollution, which can lead to poor health outcomes for people who live nearby.[9]

The Auburn Municipal Airport is located north of downtown. Under any alternative, development will be impacted by aircraft-related air

[9] California Environmental Protection Agency Air Resources Board. "Strategies to Reduce Air Pollution Exposure Near High-Volume Roadways." April 2017. https://ww2.arb.ca.gov/sites/default/files/2017-10/rd_technical_advisory_final.pdf.

and noise pollution; however, given the scale of the airport, these impacts are expected to be modest.

No significant adverse impacts on land use compatibility are expected because the Downtown Plan Update will not preclude reasonable transitions between levels or create new adjacent uses that are likely to result in incompatibilities. Proposed land use and zoning changes under both the development alternatives are expected to improve transitions between activity levels in many areas, particularly in north and west downtown.

Under all three alternatives, future downtown residents could be impacted by increased pollution given the proximity of development to arterials and highways. **However, these are not considered significant adverse impacts** because the Downtown Plan Update will comply with existing code and development guidelines to reduce the impacts and explore opportunities to further mitigate in the plan's recommendations.

URBAN FORM

All alternatives include some amount of redevelopment. As redevelopment occurs within the proposed Revised Downtown Area, there is a potential for localized land use compatibility impacts to occur where newer development is of greater height and massing than existing development. These compatibility impacts, if they occur, are temporary and will be resolved over time. The extent of these conflicts varies by alternative and can be reduced by the application of existing or new development and design standards.

With greater building heights, buildings may cast longer shadows on streets and public spaces. Additionally, the placement of taller mixed-use or residential buildings could create aesthetic impacts on adjacent low-intensity residential areas.

Mixed-use development areas promote healthy and active living by providing strong multimodal connections, open spaces, and opportunities for social connection. Residential neighborhoods at the edges of downtown Auburn provide a variety of housing types within the subarea to support the diverse housing needs of the community.

No significant adverse impacts on urban form are expected because the Downtown Plan Update will comply with existing code and development guidelines. Downtown is expected to see continued benefits to the built environment, consistent with improvements that have happened with redevelopment under the 2001 Downtown Plan.

COMMERCIAL DISPLACEMENT RISKS

Displacement is most frequently discussed in the residential context, where residents of an area are forced to relocate due to redevelopment or rapid increases in rents and housing costs as an area revitalizes, gentrifies, or redevelops. Although less frequently discussed, the process of displacement can also apply to businesses, particularly small businesses, in areas of redevelopment. Numerous studies have demonstrated the importance of small businesses in the American economy, with the Small Business Administration noting that businesses with 10 or fewer employees make up three-quarters of the nation's private-sector employers.[10] Neighborhood small businesses are important for community gathering and cohesion as well as providing local employment. In many communities, particularly lower and middle-income areas, small businesses tend to be owned by immigrants and/or people of color.

[10] U.S. Small Business Administration. (2020). Frequently asked questions about small business. https://cdn.advocacy.sba.gov/wp-content/uploads/2020/11/05122043/Small-Business-FAQ-2020.pdf.

Despite the negative impacts that can be caused by commercial and residential displacement, it is also true that cities are in a constant, if often slow, process of change and evolution. New people, investment, development, and businesses can also have many positive effects, including introducing more foot traffic, safety, and overall spending in an area. The Downtown Plan Update calls for more mixed-use development and overall revitalization. Therefore, policies should attempt to balance the positive effects of development with negative impacts, including commercial displacement.

Small businesses can be vulnerable to several types of commercial displacement:

- **Physical displacement** occurs when businesses are forced to relocate due to building sale, renovation, or redevelopment.
- **Economic displacement** occurs when businesses can no longer afford their rent due to rising property values and rents in the area.
- **Exclusionary displacement** occurs when businesses cannot afford to move into a neighborhood experiencing rapid economic change and consumer preferences.

In downtown Auburn, several areas with businesses may be prone to displacement. The Main Street corridor, described above in the *Downtown Core* section, contains a variety of small businesses in historic buildings, some of which cater to a diversity of cultural groups. This area has already seen a significant amount of redevelopment in recent years. Although many of the new developments contain ground-floor commercial space, the new spaces throughout the Puget Sound region tend to rent for higher rates and may not cater to the needs of the businesses that previously occupied the area. Local businesses owners reported the challenges of higher rents in new buildings in interviews conducted in 2022 for the Downtown Plan Update.

Another corridor in the downtown area that may be at some risk of commercial displacement is the section of Auburn Way north of MultiCare, which contains a variety of auto-oriented commercial uses, some of which are vacant or in disrepair. Many of these sites are underutilized, with large quantities of surface parking. As the area continues to develop, this area will likely see increased densities and some pressure to redevelop these uses into denser development types, although the pace of change on Auburn Way would likely be incremental and modest. Older strip malls and other aging commercial spaces are typically the most affordable to small businesses. As old retail spaces are redeveloped into mixed-use developments, the number of retail spaces affordable to local business owners could be reduced over multiple decades.

The potential for significant adverse impacts for commercial displacement is expected under all of the alternatives, although there are some potential differences in location and degree.

3.2.3 Impacts of Alternative 1, No Action

Regional and Local Policy Consistency

Alternative 1 would not amend current plans or regulations to reflect changed conditions. However, Alternative 1 would provide the least-robust approach to meet local and regional goals and policies. Growth projections for Alternative 1 show that the area will meet PSRC's future growth target of 45 activity units per acre within the existing RGC boundary; **thus, no significant adverse impacts are expected**. However, if the City works with PSRC and gets approval to expand the RGC boundary to be consistent with the proposed Revised Downtown Area, but does not adopt zoning changes to increase development capacity, the area is unlikely to meet future growth targets under Alternative 1. **This would be inconsistent with**

City and regional growth policies and would be considered a significant impact.

Land Use Compatibility

Alternative 1, which reflects the City's existing zoning, continues car-dependent development patterns in north downtown. This contributes to vehicular air pollution, but because less development is expected under Alternative 1, fewer people would be impacted by air and noise pollution from the airport.

Existing land use and zoning in the proposed Revised Downtown Area are mixed, particularly in north and west downtown. As a result, some areas may lack transitions between activity levels or have adjacent uses where there is potential for conflict.

This is not considered a significant impact from the Downtown Plan Update, because it is the existing condition of the area and is not occurring as the result of a change proposed by this plan. However, Alternative 1 would also see no benefit to land use compatibility that proposed changes offered by both development alternatives.

Urban Form

Under Alternative 1, development within the downtown area is likely to continue within the downtown core area, while adjacent neighborhoods would likely develop more slowly, based on market conditions and the underlying zoning. Redevelopment of the downtown core would likely continue to provide a strong urban fabric that supports the City's vision for a more pedestrian-oriented environment. Outside of the core area, development may continue to be auto-oriented, particularly in commercial zones. This could result in abrupt transitions in urban form between the higher density of the downtown core area and existing residential areas.

In east downtown, this could result in taller buildings and higher density development immediately adjacent to lower density development, particularly in the east downtown area.

These impacts occur in Alternative 1 to a greater degree than other alternatives. **However, no significant adverse impacts are expected because this development provides an overall improvement to the aesthetics and human experience of downtown** through activation, economic development, new housing, and streetscape enhancements.

Over the last 20 years, redevelopment in the DUC has replaced some of the smaller scale mid-century buildings that predated the recent downtown growth. Given the extent of existing DUC zoning already in place, this trend is likely to continue under Alternative 1. However, because redevelopment is considered a natural part of urban growth and provides significant benefit to the aesthetics and human experience of downtown, **this is not considered a significant impact on urban form**.

Impacts to Areas Adjacent to Downtown

Redevelopment under the Alternative 1 may create abrupt transitions between the higher density DUC zones and the adjacent residential areas. Refer to the City's 2024 Comprehensive Plan EIS for proposed land use and zoning changes in areas around downtown, and any potential impacts.

Commercial Displacement

Alternative 1 retains current zoning in the downtown area and the current RGC boundary. With this alternative, development would still occur throughout the downtown area, which may result in some commercial displacement as detailed in Impacts Common to All Alternatives. The area's most prone to commercial displacement would likely be the downtown core, areas along Main Street

(particularly older buildings), and some lower intensity auto-oriented development in north downtown.

There is potential for some significant adverse impacts for commercial displacement, but there are existing city policies, programs, and partnerships that can help support and promote local businesses. The Downtown Plan Update is also exploring recommendations to increase access to affordable commercial space, which could reduce impacts.

3.2.4 Impacts of Alternative 2, Moderate Growth

Regional and Local Policy Consistency

Growth projections show that under the changes proposed in Alternative 2, the City could meet PSRC's future growth target of 45 activity units/acre either within the existing RGC boundary or across the larger proposed Revised Downtown Area.

No significant adverse impacts on regional or local policy consistency are expected, as adopting these changes would allow the City to meet future growth targets, using either the existing or the proposed Revised Downtown Area boundary.

Use Compatibility

Alternative 2 proposes land use changes to encourage growth, expand mixed-use development opportunities, and create more housing throughout downtown, particularly in the north downtown area. Redevelopment in north downtown would provide opportunities for the development of more socially connected communities with multimodal improvements that support active living.

North downtown is partially impacted by the Airport Overlay Zone, and ACC 18.38.060 addresses potential conflicts by prohibiting certain uses. Proposed heights meet the requirements of 18.38.050 – Airport Overlay's intent and boundaries in the Auburn Municipal Code.[11] However, there may be some increase in noise and air pollution issues in these areas due to both the airport and the Auburn Way N corridor. Retaining the M-1 zone while also encouraging mixed-use development in north downtown could result in some use compatibility challenges. However, these light industrial areas buffer new redevelopment from the active railroad corridor, which is beneficial to new development.

In other areas, the changes proposed under Alternative 2 are expected to improve use compatibility between various land uses.

There is potential for some impacts on future residents, particularly in the north downtown area, from airplane noise and air pollution, but these are not considered significant adverse impacts because the Downtown Plan Update will comply with existing code and development guidelines to reduce the impact and explore opportunities to further mitigate in the plan's recommendations.

Urban Form

As described earlier in Chapter 2, section 2.1.2, building heights described below are maximum height allowed before bonuses or exceptions in the proposed DUC districts. When evaluating the proposed changes for potential impacts, this Urban Form analysis considered that future buildings could be slightly taller than the maximum height allowed in some areas of downtown.

Alternative 2 increases building heights in the southern portion of the downtown core area to 125 feet and creates a new node of

[11] Auburn Municipal Code, https://auburn.municipal.codes/ACC/18.38.050.

mixed-use development in the north downtown area with 55-foot building heights. It also increases the density and building types in DUC Neighborhood Residential districts adjacent to the downtown area, providing a more gradual transition in density and building heights between the downtown core area and residential areas that surround downtown. As has occurred within the downtown core, improvements to the built environment (such as wider sidewalks, permeable ground floors, and new commercial spaces) could happen in this area as well.

Along Main Street, a new overlay district would continue to allow infill mixed-use development but would promote buildings that are consistent and integrated with the scale of the existing mid-century buildings along this corridor. The overlay would emphasize zero-lot line development and flexible uses and include design standards that are currently applied to the DUC zone as well as potential reductions to parking for small-footprint buildings. Additional flexibility for arts-related uses would complement the emphasis in past plans on development of a lively arts scene in downtown.

The proposed DUC Neighborhood Residential zoning district would align with the existing uses of these areas, but allow for a wider range of housing types, consistent with the recommendations of the Housing Action Plan and HB 1110 requirements. Redevelopment in these areas will likely happen slowly over time and as parcels become available. Increasing the types of housing allowed in these areas is not expected to significantly increase displacement risks in these areas.

Creating a new Health and Wellness zoning district around MultiCare, would provide a more focused area within downtown Auburn for medical and wellness commercial businesses and would allow for overall economic growth of this key employment anchor within Auburn.

A new flex-residential district in west downtown would allow a wider range of commercial and light-industrial businesses that are compatible with residential areas, such as breweries and small workshops. This could support overall feasibility of redevelopment and growth in this area.

Redevelopment could also provide opportunities to bring greater activation to the areas adjacent to Veterans Memorial Park, a key open space asset located northeast of downtown. Streets throughout the north downtown area are disconnected and circulation is challenging for people walking and biking. (See Section 4.1.4, *Existing Street Network*, in Chapter 4, *Transportation*.) The area is bisected by busy arterials, with limited opportunities for safe crossing. (See Section 4.1.6, *Safety*, in Chapter 4, *Transportation*.)

There is the potential for some impacts on human well-being if redevelopment occurs without improvements that promote safe multimodal access and circulation to streetscapes, and access to key destinations such as Veterans Memorial Park. However, these are not considered significant adverse impacts because the Downtown Plan Update includes recommendations for updating and applying design standards to these areas. These design standards will also ensure that redevelopment continues to result in an overall aesthetic benefit to the urban form of downtown.

Impacts on Areas Adjacent to Downtown

Redevelopment under Alternative 2 would provide more opportunities for transition between higher density zones in the downtown core and north downtown and the adjacent residential areas. Adding these transition areas between the dense development of the downtown core and surrounding residential areas can improve the overall urban form and aesthetics of the subarea and the adjacent communities.

No significant adverse impacts to urban form and aesthetics are expected. Refer to the City's 2024 Comprehensive Plan EIS for proposed land use and zoning changes in areas around downtown, and any potential impacts.

Commercial Displacement

Alternative 2 proposes 60-foot building heights in the Main Street Overlay along the eastern half of Main Street. More modest zoning changes in this area would encourage slower redevelopment, which could slow commercial displacement as older buildings redevelopment over a longer timeframe. The Core-55 zoning district along Auburn Way in this alternative has the same considerations.

Alternative 2 proposes moderate land use changes along the Main Street corridor, where there is a significant cluster of small, local businesses. Less commercial displacement would occur in this area under Alternative 2 than the other alternatives. **However, there is still potential for some significant adverse impacts for commercial displacement in other areas of downtown.** There are existing city policies, programs, and partnerships that can help support and promote local businesses. The Downtown Plan Update is also exploring recommendations to increase access to affordable commercial space, which could also reduce impacts.

3.2.5 Impacts of Alternative 3, Higher Growth

Regional and Local Policy Consistency

Growth projections show that under the changes proposed in Alternative 3, the City would meet PSRC's future growth target of 45 activity units/acre either within the existing RGC boundary or across the proposed Revised Downtown Area.

No significant adverse impacts on regional or local policy consistency are expected, as adopting these changes would allow the City to meet future growth targets, using either the existing or the proposed Revised Downtown Area boundary.

Use Compatibility

Alternative 3 proposes land use changes that are similar to Alternative 2, but with taller buildings that create more capacity for mixed-use development in the downtown core and north downtown.

Taller buildings in north downtown while still consistent with the Airport Overlay Zone, could increase housing in an area with the potential for significant air and noise pollution.

There is slightly more potential in Alternative 3 for impacts on future residents, particularly in the north downtown area, from airplane noise and air pollution, but these are not considered significant adverse impacts because the Downtown Plan Update will comply with existing code and development guidelines to reduce the impact and explore opportunities to further mitigate in the plan's recommendations.

Urban Form

As described earlier in Chapter 2, Section 2.1.2, building heights described below are maximum height allowed before bonuses or exceptions in the proposed DUC districts. When evaluating the proposed changes for potential impacts, this Urban Form analysis considered that future buildings could be slightly taller than the maximum height allowed in some areas of downtown.

Improvements to urban form in Alternative 3 are similar to Alternative 2, with particular opportunities for active living and socially connected housing in the expanded footprint of the proposed DUC districts.

Similar to Alternative 2, Alternative 3 would increase building heights to 125 feet within the southern portion of the downtown core area and create a new node of mixed-use development in the north downtown area. Alternative 3 proposes in north downtown 75-foot-tall buildings, higher than in Alternative 2. Along the Main Street corridor through the downtown core and west downtown, Alternative 3 proposes the Core-75 zoning district (allowing building heights similar to the current DUC zone.)

Alternative 3 also proposes a Health and Wellness district around MultiCare, but with 125-foot tall buildings allowed, taller than Alternative 2. This would provide a more focused area within downtown Auburn for medical and wellness commercial businesses and allow for overall economic growth of this key employment anchor within Auburn.

Proposed DUC Neighborhood Residential districts in Alternative 3 are the same as in Alternative 2.

Multimodal access challenges described in Alternative 2 would be similar but slightly higher in Alternative 3 given the higher number of potential residents in the North Downtown area.

There is slightly more potential in Alternative 3 for impacts on human well-being if redevelopment occurs without improvements that promote safe multimodal access and circulation to streetscapes and, and access to key destinations such as Veterans Memorial Park. However, these are not considered significant adverse impacts, because the Downtown Plan Update includes recommendations for updating and applying design standards to these areas. These design standards will also ensure that redevelopment continues to result in an overall aesthetic benefit to the urban form of downtown.

Impacts on Areas Adjacent to Downtown

Redevelopment under Alternative 3 would provide some transitions between higher density districts in the downtown core and north downtown and the adjacent residential areas, but the expansion of the DUC Core-75 district under this alternative creates some areas of abrupt transition between high-density and low-density areas. While redevelopment is projected to happen slowly over the next 20 years, design standards that prescribe features such as transitional height limits, setbacks, or walls could mitigate these issues.

No significant adverse impacts on land use are expected. Refer to the City's 2024 Comprehensive Plan EIS for proposed land use and zoning changes in areas around downtown, and any potential impacts.

Commercial Displacement

Alternative 3 proposes 75-foot heights along the Main Street corridor and along Auburn Way. While this would likely encourage slightly more redevelopment, a substantial majority of historic buildings would not be redeveloped, at least over the next 20 years. However, in both Alternatives 2 and 3, the DUC Core-125 district, which allows 125-foot tall buildings in the southern part of the downtown core would likely be the most attractive place for large-scale development projects.

There is potential for some significant adverse impacts for commercial displacement, but existing City policies, programs, and partnerships can support and promote local businesses. The Downtown Plan Update is also exploring recommendations to increase access to affordable commercial space, which could also reduce impacts.

3.3 Mitigation Measures

3.3.1 Mitigation Proposed for Alternatives

All of the alternatives focus on downtown as a center for future growth and economic development within the City, which is broadly supported by the City's existing policies and goals. Coordinating any future RGC boundary adjustments with land use and zoning changes will ensure the City meets future regional growth targets.

Compatibility challenges and urban form changes due to growth are not a new or uncommon phenomenon to this area and can be minimized or mitigated through design standards, careful planning and coordination of multimodal access improvements, and coordination of planned projects and improvements in the area.

Auburn's City Code contains regulations that help to ensure land use compatibility. A summary of these regulations, which would mitigate impacts associated with the alternatives, is presented below.

DEVELOPMENT REGULATIONS

ACC Section 14.02.040 establishes zoning and development regulations. These development regulations contain provisions governing the design of buildings, site planning, and provisions to minimize land use incompatibilities. Commercial and mixed-use zones generally contain provisions relating to building form and design, such as standards related to height, bulk, scale, density, setbacks, floor area ratio, screening, floor plate size, landscaping, etc. Regulations are in place to address such issues related to the implementation of all alternatives.

DESIGN STANDARDS

The City's existing design standards for the DUC zone have successfully shaped the recent redevelopment in Auburn, implementing the City's goals for pedestrian-oriented streets, public spaces, active ground floors, and other public realm benefits. The City will continue to update the design standards and apply them to new DUC areas.

When updating design standards for the area, the City may also consider strategies to promote more flexibility, facilitate businesses moving into spaces and newer buildings, and reduce some commercial displacement risk. Typical approach are noted in the list below, but the City may take other approaches when standards are updated.

- Promote flexible ground-floor layouts to accommodate different types of business and allow for expansion.
- Add commercial ground-floor requirements that accommodate a range of uses (high ceilings for ventilation, etc.).
- Consider maximum retail sizes (outside of certain types such as grocery, hardware, etc.).
- Require commerce space occupancy to maintain Multifamily Property Tax Exemption (MFTE) benefits.
- Streamline permitting and licensing processes.



A Micro-Restaurant Space at the La Scala Source: Carleton Hart Architecture.

SOURCE: Leland Consulting Group

3.4 Significant and Unavoidable Adverse Impacts on Land Use

The City structured the analysis of the 2024 Auburn Downtown Subarea Plan Update to understand what land use changes were needed to accommodate future growth, align with regional and local growth policies, and retain the City's designation as an RGC.

Under all alternatives, additional growth and development will occur in the proposed Revised Downtown Area, leading to increases in height and bulk of buildings and increased land use intensity. This transition is unavoidable but is not considered a significant or adverse impact within an urban area designated as a mixed-use center in the Comprehensive Plan.

No Action does not amend current plans or regulations and is predicted to accommodate less future growth than the two action alternatives. If the City gets approval from PSRC to expand the RGC boundary to be consistent with the proposed Revised Downtown Area, but does not adopt zoning changes to increase development capacity, the area is unlikely to meet future growth targets under Alternative 1. The City could avoid this potentially significant impact by adopting some zoning changes to increase development capacity.

There is a potential that new downtown residents will be exposed to increased noise and air pollution from the airport, adjacent uses, and arterials and highways. The Downtown Plan Update will comply with existing codes and development guidelines and explore other ways to reduce the impacts in the plan's recommendations.

As is noted earlier in this chapter, cities are in a constant state of change and evolution, often slow, and sometimes more rapid. The 2024 Auburn Downtown Subarea Plan Update is exploring design standards and programmatic approaches to minimize the potential

for negative impacts as the area grows. It is not feasible to eliminate all risk of commercial displacement, and this is not considered a significant or adverse impact within an area identified both locally and regionally as a growth center.

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CHAPTER 4 Transportation

This chapter describes the affected environment, potential impacts, and mitigation measures for transportation. A multimodal transportation analysis is used to evaluate the potential impacts from enacting proposed zoning and transportation network changes in downtown Auburn. The analysis identifies significant impacts using thresholds developed for the following modes: vehicle and transit. Safety impacts are also considered.

4.1 Affected Environment

This section describes the existing conditions in the study area.

4.1.1 Regulatory Environment

The GMA, passed by the Washington State Legislature in 1990, requires jurisdictions to include a Transportation Element in their Comprehensive Plans. The Transportation Element must define a level of service (LOS) standard to be used for long-term planning purposes to evaluate the performance of locally owned arterials and transit routes. The GMA also requires transportation concurrency, a regulatory process to ensure that development be permitted only if

transportation improvements are implemented concurrently with development such that LOS does not fall below the adopted standard.

4.1.2 Study Area Existing Transportation Network

Characteristics of the study area that influence mobility include streets, public transit, trails, and sidewalks. These elements of the City's transportation system are described in the following subsections. Where relevant, this review of the affected environment focuses on roadway segments and intersections in and around the study area that may be affected by growth targeted under the development alternatives.

The existing transportation network in the Downtown Subarea includes all modes, including pedestrians, bicycles, transit, autos, and freight.

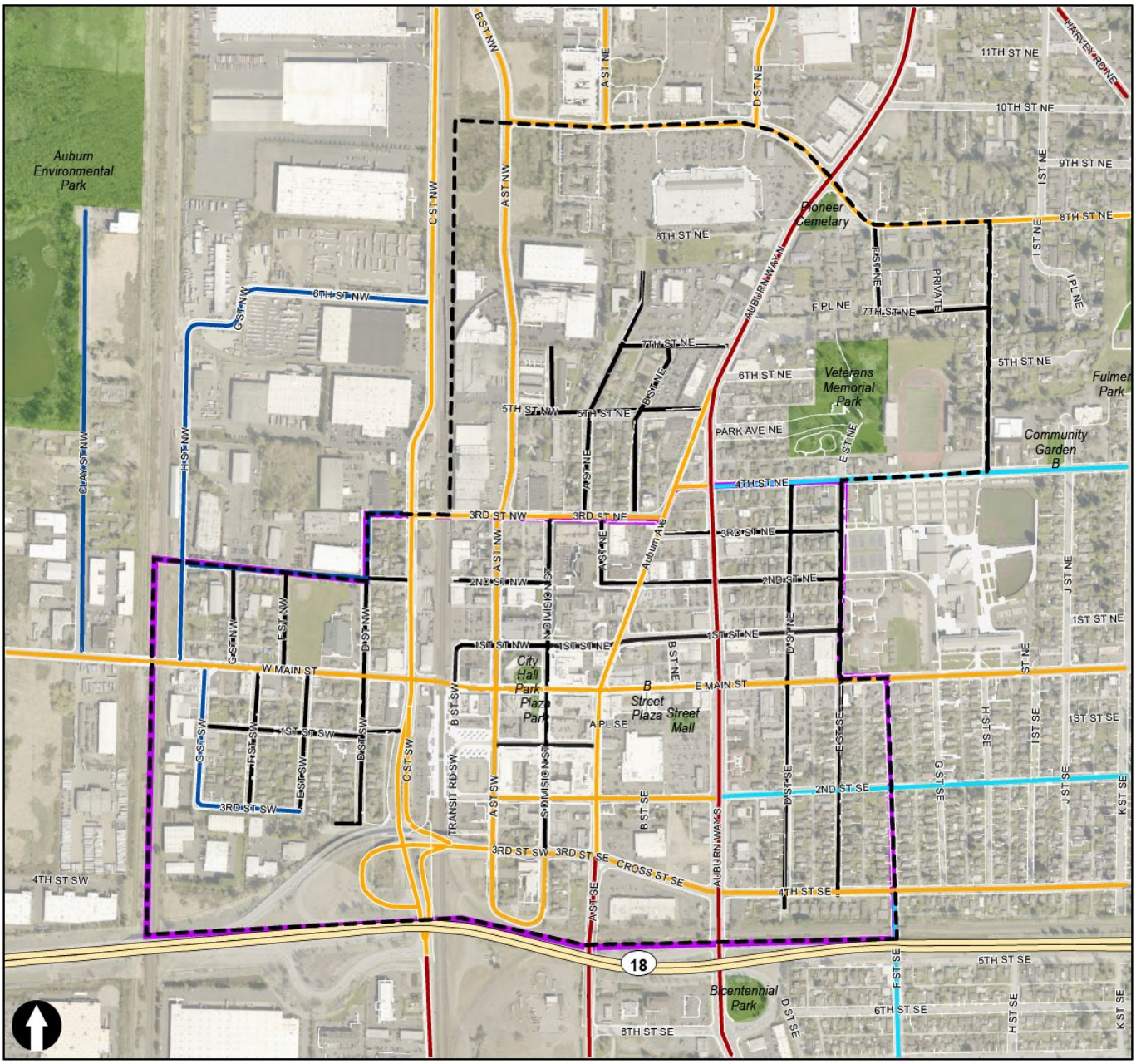
4.1.3 Existing Street Network

REGIONAL ACCESS

The City of Auburn is located south of Seattle, Washington. It has access to state routes primarily through SR 167 and SR 18. Major connectors in the City are SR 164, Auburn Way N/S, and W/E Main Street.

FUNCTIONAL CLASSIFICATION OF STREETS

The street system functions as a network. Functional classification is the hierarchy by which streets and highways are defined according to the character of service they provide. The three main classes of streets in Auburn are arterials, collectors, and local streets. Existing street classifications are shown in **Figure 4-1**. Understanding the existing functional classification helps establish which corridors will provide for the future movement of people and goods, as well as emergency vehicle access.



2024 Roadway Classification

- Principal Arterial
- Minor Arterial
- Collector
- Industrial Collector
- Local (Not show on map out side of study area)
- Study Area
- Current Downtown / RGC
- SR-18
- Parks

FIGURE 4-1 Roadway Network

As development is being considered, accommodation for the appropriate transportation corridors is crucial. In the downtown study area, most streets are primarily collector and local roadways, with three arterials running north–south and one east–west connection.

CORRIDOR LEVEL OF SERVICE

The City uses an LOS rating system as a way to evaluate the operations of its roadway system. LOS is a concept used to describe traffic operations from the driver's perspective. LOS ratings are defined by intersection delay in seconds—LOS ranges from LOS A, which signifies no congestion and little delay, to LOS F, which signifies substantial congestion and delay. **Table 4-1** summarizes the LOS and delay thresholds specified in the Highway Capacity Manual, which is a standard methodology for measuring intersection performance.

TABLE 4-1 LOS and Delay Thresholds for Signalized and Unsignalized Intersections

LOS	Description	Signalized Intersections (Delay in Seconds)	Unsignalized Intersections (Delay in Seconds)
A	Free-flowing Conditions	<10	0–10
B	Stable Flow (slight delays)	>10–20	>10–15
C	Stable Flow (acceptable delays)	>20–35	>15–25
D	Approaching Unstable Flow (tolerable delay)	>35–55	>25–35
E	Unstable Flow (intolerable delay)	>55–80	>35–50
F	Forced Flow (congested and queues fail to clear)	>80	>50

SOURCE: Highway Capacity Manual 6th Edition

The City tracks LOS in two ways:

- For some intersections along its major corridors, it considers the volume-weighted delay of intersections along a corridor.
- For other intersections along major corridors, it evaluates those intersections separately.

Corridor LOS and isolated intersection LOS are the primary measurements that the City uses to identify needed improvements for roadway capacity. All arterials and collectors in Auburn have designated LOS standards. Within the study area, most corridors have a LOS standard of D; however, some corridors and isolated intersections are permitted to operate at LOS E or F. These LOS standards are consistent with the 2001 Auburn Downtown Plan.

The City measures intersections' operations based on delays measured during the weekday PM peak hour.

Traffic operations were analyzed using the Synchro 11 software package and *Highway Capacity Manual* methodology. The Synchro network reflects the study area's existing roadway network, including segment and intersection geometry, and signal timings. The network also includes existing traffic volumes that were collected in spring and summer 2022. For signalized and all-way stop-controlled intersections, the LOS is based on the average delay for all movements. For minor street stop-controlled intersections, LOS is based on the movement with the highest delay.

This study considers 30 existing intersections, 26 of which are signalized. Table 4-2 summarizes the existing corridor 2022 LOS for study intersections in the PM peak hour in respective corridor segments and existing intersection LOS for study intersections that do not fall within a concurrency corridor.

Figure 4-2 summarizes the existing intersection LOS in the PM peak hour at the study intersections. The LOS analysis indicates that vehicles move through the study area with relatively little delay during the PM peak hour. All corridors currently meet the City's minimum LOS standards. One intersection does not meet the City's minimum LOS standards.

TABLE 4-2 2022 Downtown Auburn Corridor Level of Service

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	Average LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS					
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C/24
		4	Signal		
		5	Signal		
		6	Signal		
3	Auburn Way S from E Main St to M St SE	7	Signal	D	C/28
		9**	Signal		
		6	Signal		
		8	Signal		
		10	Signal		
10	Auburn Ave/A St from 6th St SE to E Valley Access Rd	1**	Signal	D	A/9
11	Main St from West Valley Hwy to R St	18	Signal	D	C/20
		19	Signal		
		20	Signal		
		6	Signal		
		21	Signal		
13	C St SW from Ellingson Rd to SR 18	25**	Signal	D	B/15
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC***	D	C/22
		14	Signal		

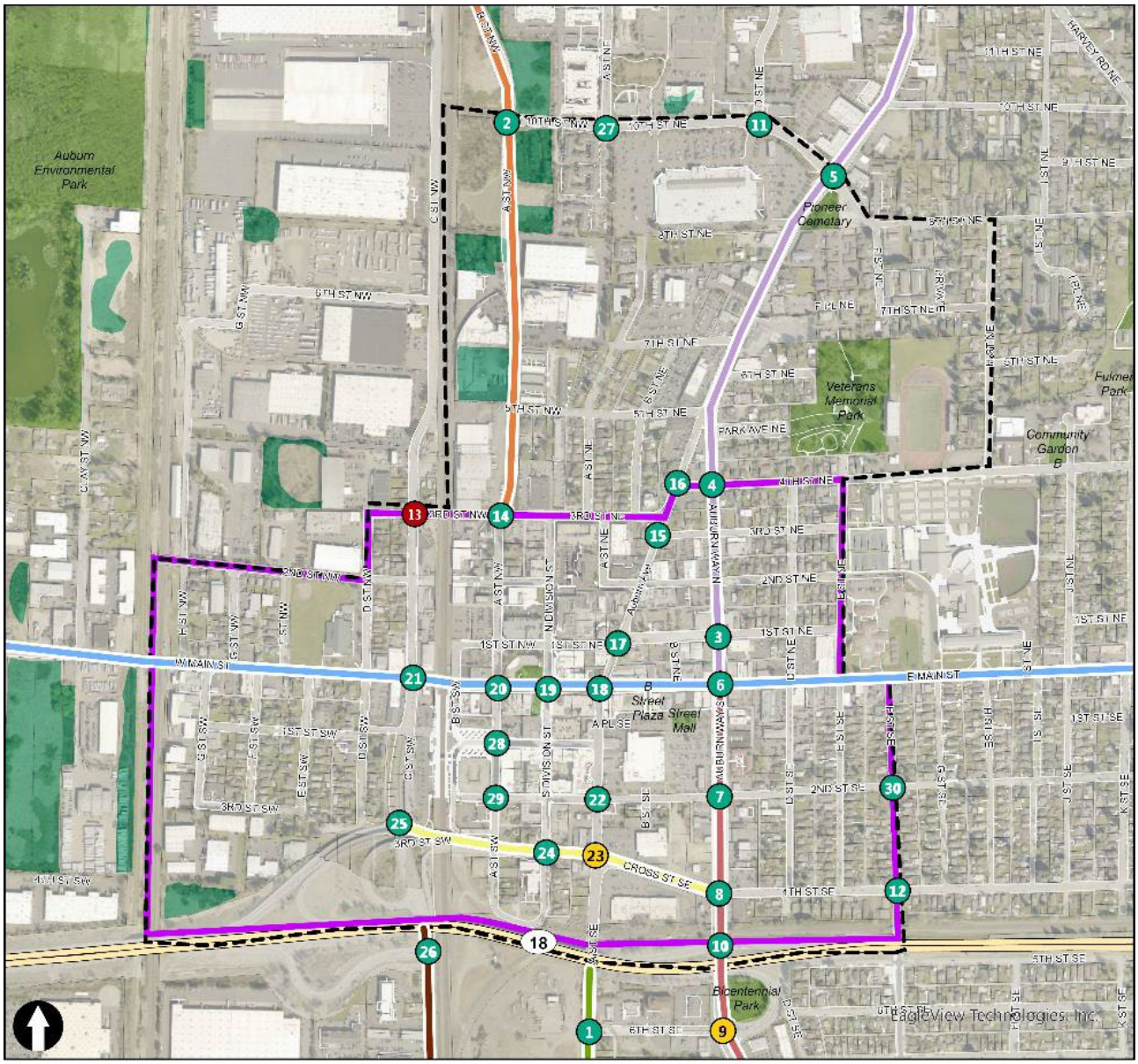
Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	Average LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to Auburn Way S	23	Signal	E	B/19
		24	Signal		
		8	Signal		
		25	Signal		
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS					
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B/20
N/A	F St SE & 4th St SE	12	Signal	E	B/15
N/A	C St SW & 3rd St NE	13	Signal	E	F/90
N/A	Auburn Ave & 3rd St NE	15	Signal	E	B/14
N/A	Auburn Ave & 4th St NE	16	Signal	E	A/4
N/A	Auburn Ave & 1st St NE	17	Signal	E	A/9
N/A	A St SE & 2nd St SE	22	Signal	D	C/30
N/A	10th St NE & A St NE	27	TWSC	D	B/11
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC****	D	A/8
N/A	A St SE & 2nd St SE	29	Signal	D	B/13
N/A	F St SE & 2nd St SE	30	AWSC	D	A/8

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan.

*** Two-Way Stop Controlled.

**** All-Way Stop Controlled.



Note: Downtown Urban Center area shown on this map is consistent with the Current Downtown/ RGC area shown on other maps.

FIGURE 4-2 Intersection Level of Service Existing PM Peak Hour

TRANSIT SERVICES

The City of Auburn does not administer transit service. The City coordinates service with King County Metro Transit, Pierce Transit, Sound Transit, and Muckleshoot Tribal (MIT) transit. Transit in the City operates at local service (30-minute headways in the peak period) and frequent/express service (less than 30-minute headways in the peak period). Service is also offered through DART (Dial-A-Ride Transit), which arranges transit service on demand. As noted above, the City of Auburn has a rail station, served by Sound Transit's Sounder train, which runs primarily during peak AM/PM weekday hours. **Figure 4-3** represents the existing transit network.

PEDESTRIAN NETWORK

Downtown Auburn offers a complete pedestrian network, in which sidewalks are generally available on both sides of most streets, and there are also two multiuse trails in proximity to the study area (**Figure 4-4**). Overall, this supports a positive pedestrian environment, as businesses, shops, and single-family homes in the downtown core generally benefit from sidewalks and street trees. However, there are gaps in existing sidewalk infrastructure in the study area and some older sidewalks are 5 feet wide without planters to provide comfortable walkability. When feasible with redevelopment or major transportation projects, these are widened to meet the City's current standards.

BICYCLE NETWORK

Providing better accommodations for people who wish to travel by bike is a priority for the City. Current infrastructure benefits from access to regional trails such as the Interurban Trail directly west of downtown. However, there are few existing bicycle facilities in the City, with only existing sharrows and bike lanes in the study area. There are also two multiuse trails in proximity to the study area as seen in **Figure 4-5.**

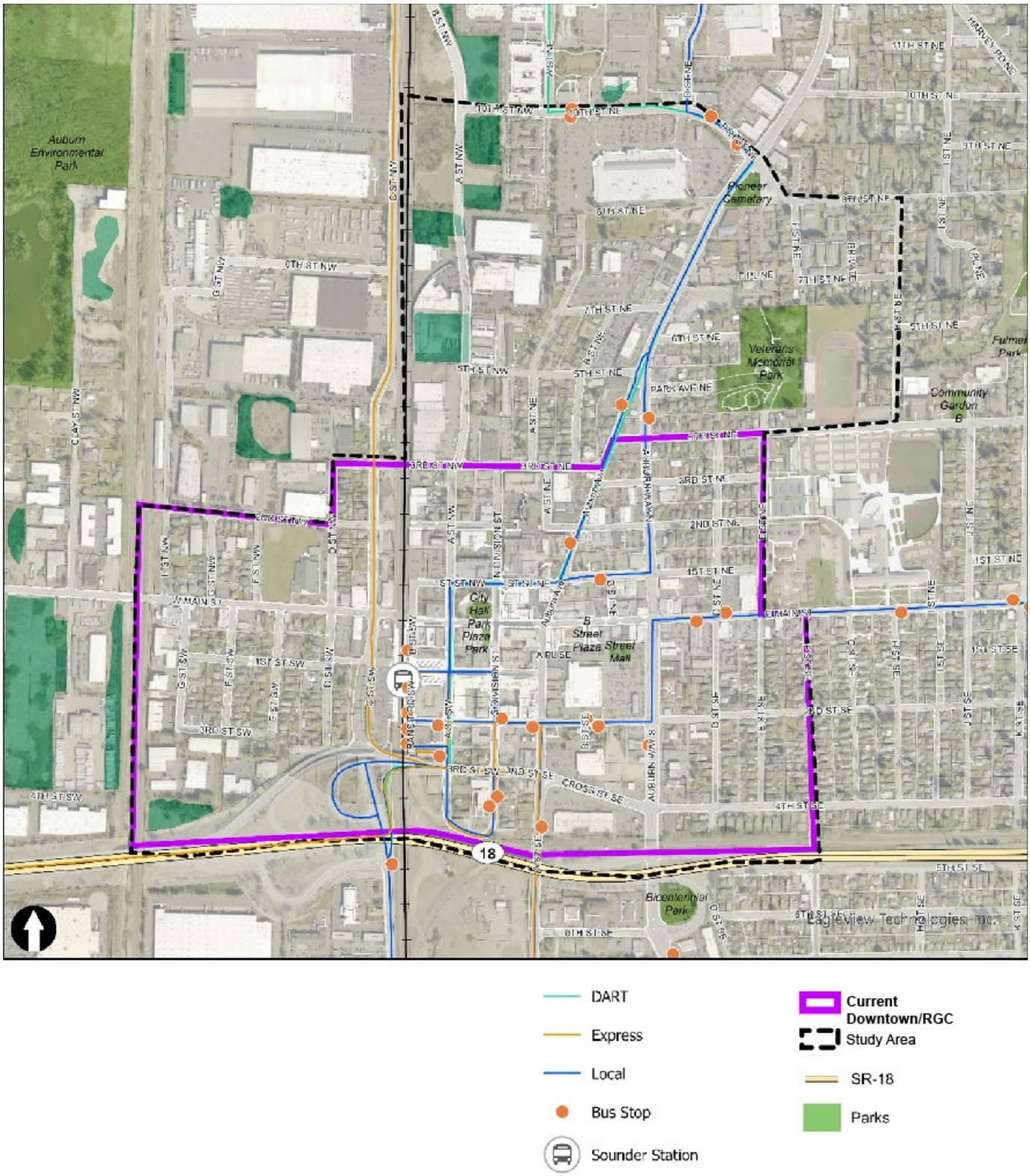


FIGURE 4-3 Transit

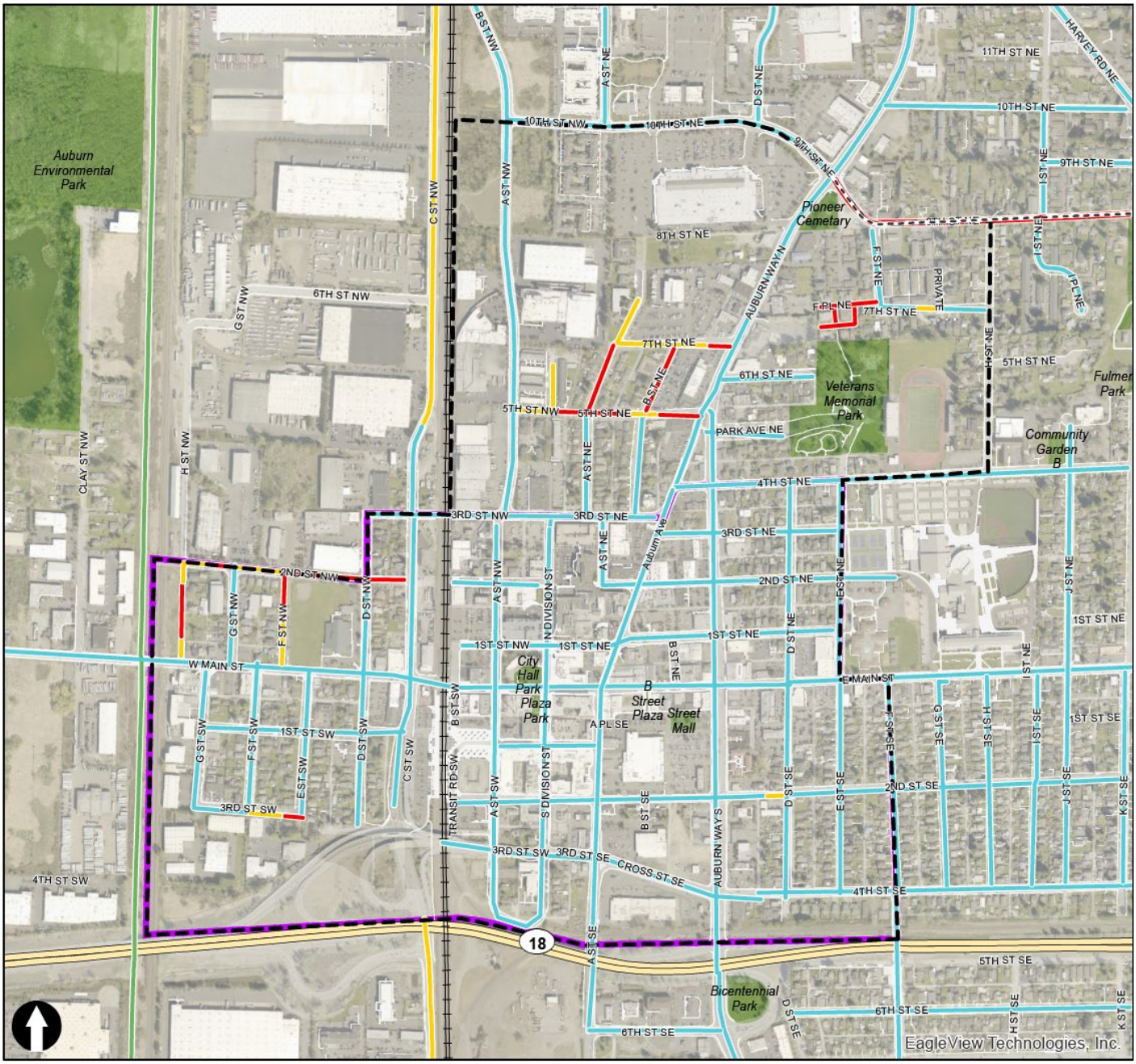


FIGURE 4-4 Pedestrian Network

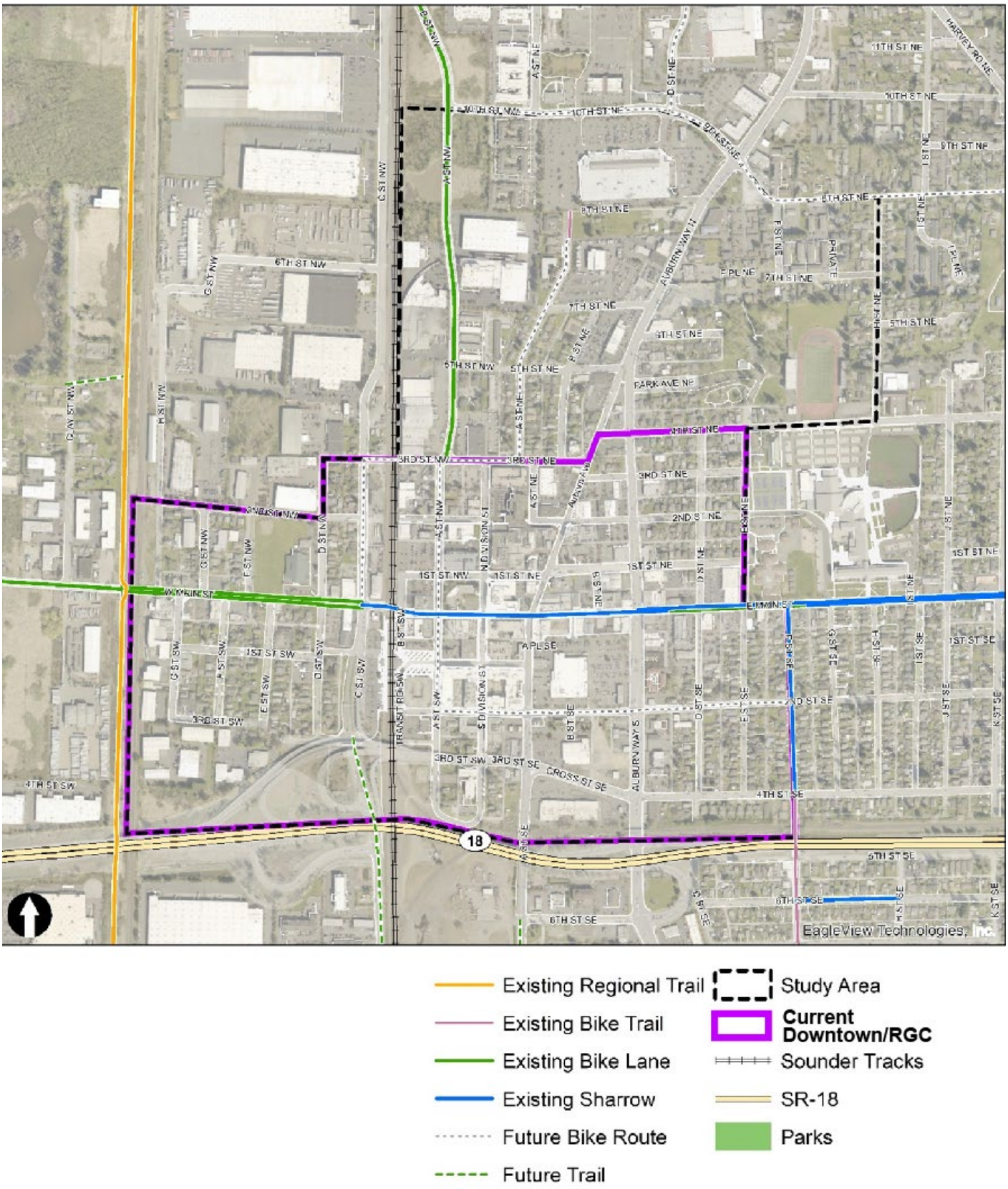


FIGURE 4-5 Bicycle Network

4.1.4 Parking

According to the Comprehensive Downtown Parking Management Plan (CDPMP), adopted January 2014, there were a total of 4,879 parking spaces in the Downtown Urban Center (DUC) as of December 2011. This includes on-street public parking, off-street public parking, and off-street private parking. Figure 4-6 shows the locations of parking lots downtown. Other parking is included on-street with time limits.

4.1.5 Safety

Safety is a high priority for the City to promote a downtown environment that accommodates multiple transportation modes. The City's comprehensive plan policies include a goal to "*significantly reduce or eliminate traffic fatalities and serious injuries through a safe systems approach*." Figure 4-7 shows the locations in downtown Auburn with the highest density of collisions, as reported in the City's 2020 Local Road Safety Plan. As shown by the heatmap, many collisions occurred along principal and minor arterial roadways, as well as major intersections. At-grade rail crossing intersections were also evaluated for safety, including several in the downtown study area. There have been recent upgrades to the rail crossings, such as pre-signals that prevent vehicles from stopping on the crossing.

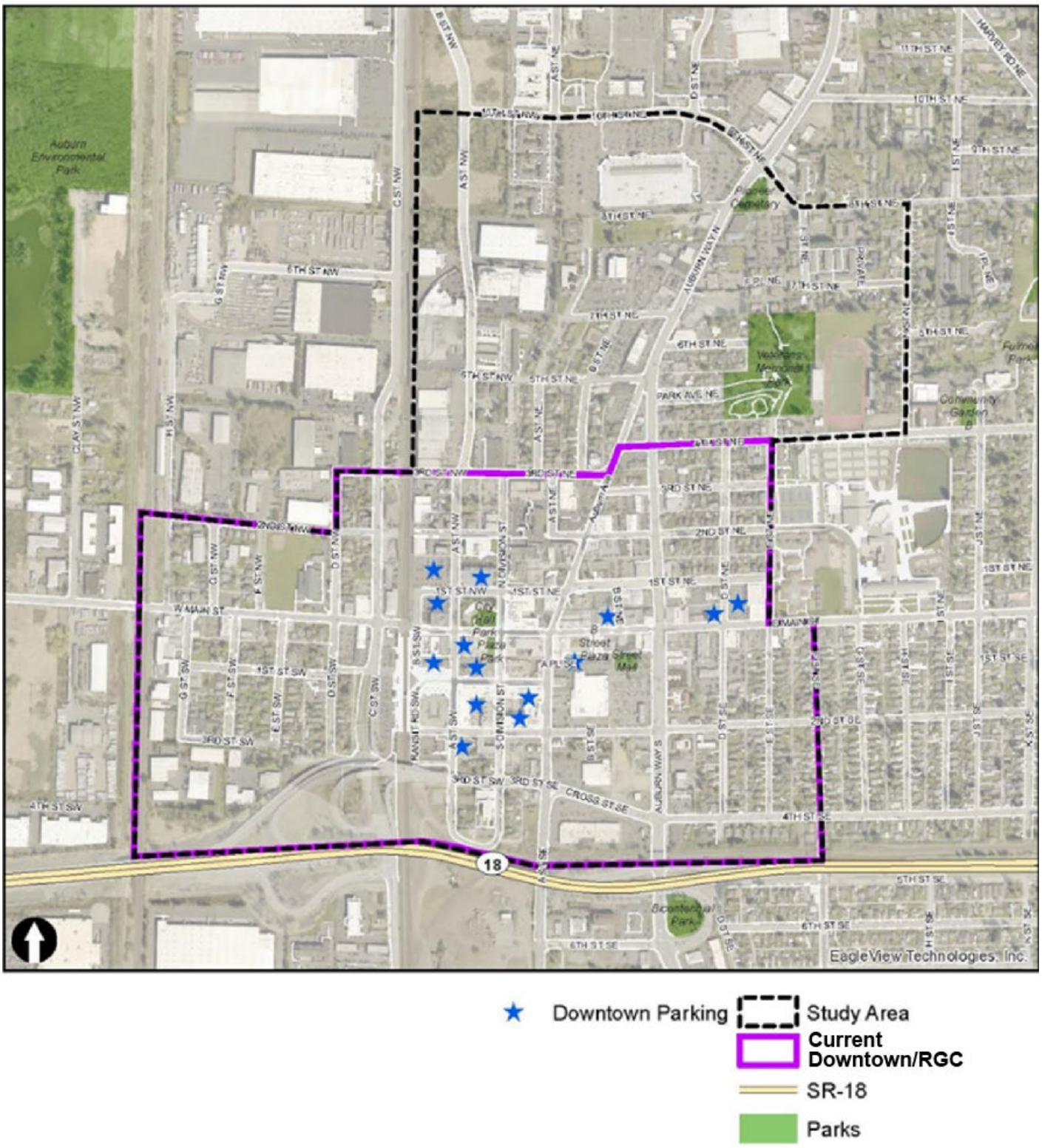


FIGURE 4-6 Parking

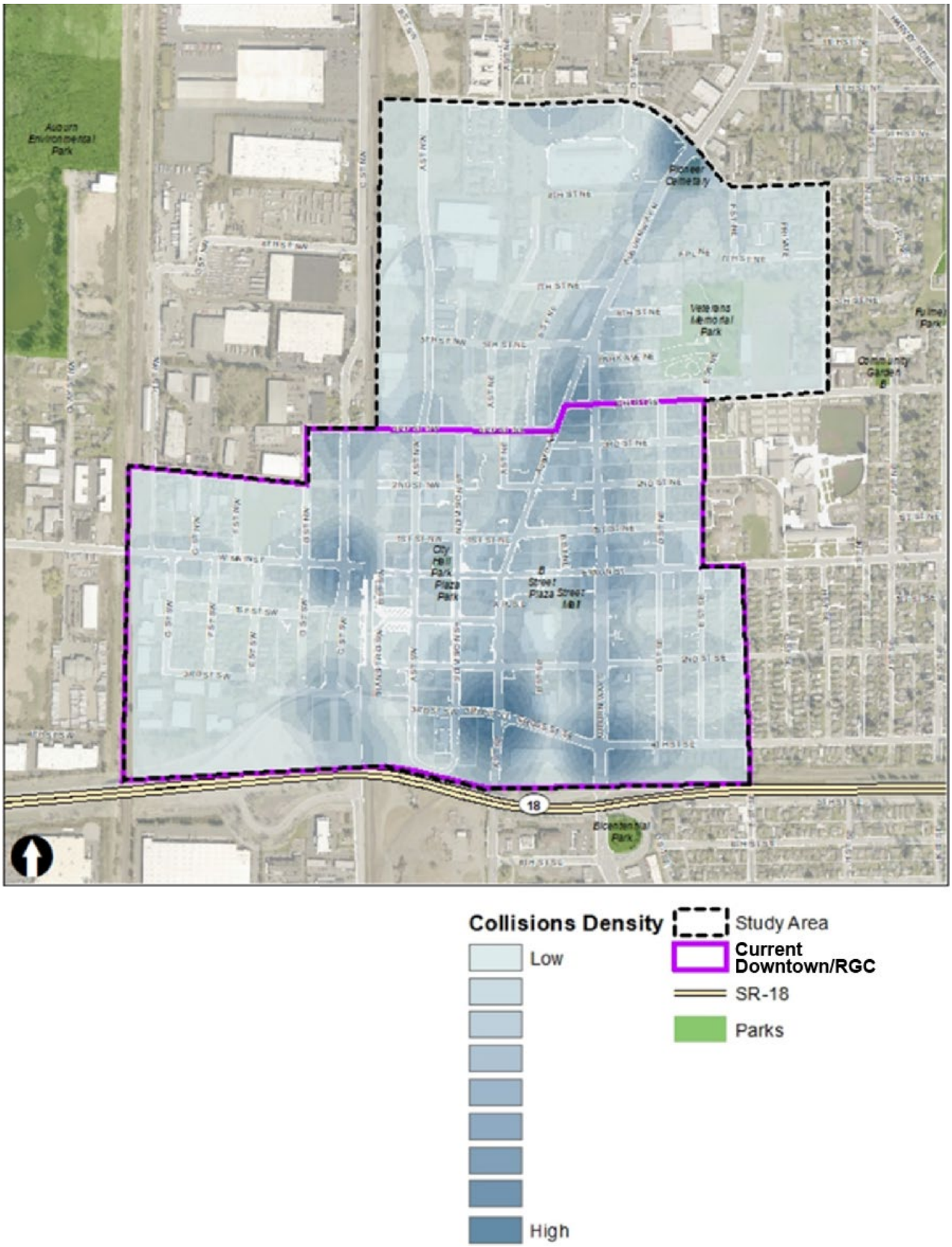


FIGURE 4-7 **Safety**

4.1.6 Truck Routes

Several freight routes traverse the study area. Freight and Goods Transportation System (FGTS) classification represents the freight tonnage moved on a certain corridor. **Table 4-3** references Washington State Department of Transportation (WSDOT) standards and FGTS classifications. **Figure 4-8** represents the freight network in the study area. There are four freight routes that run north/south through the study area with FGTS levels of T-3, T-2, and T-1. Freight routes that run east/west through the study area have FGTS levels of T-3. C Street SW operates with the highest FGTS classification.

TABLE 4-3 **WSDOT Freight Classifications and Standards**

Classification	Amount of Freight Carried
T-1	More than 10 million tons per year
T-2	4 million to 10 million tons per year
T-3	300,000 to 4 million tons per year
T-4	100,000 to 300,000 tons per year
T-5	At least 20,000 tons in 60 days and less than 100,000 tons per year

SOURCE: Washington State Freight and Goods Transportation System (FGTS) 2021 Update

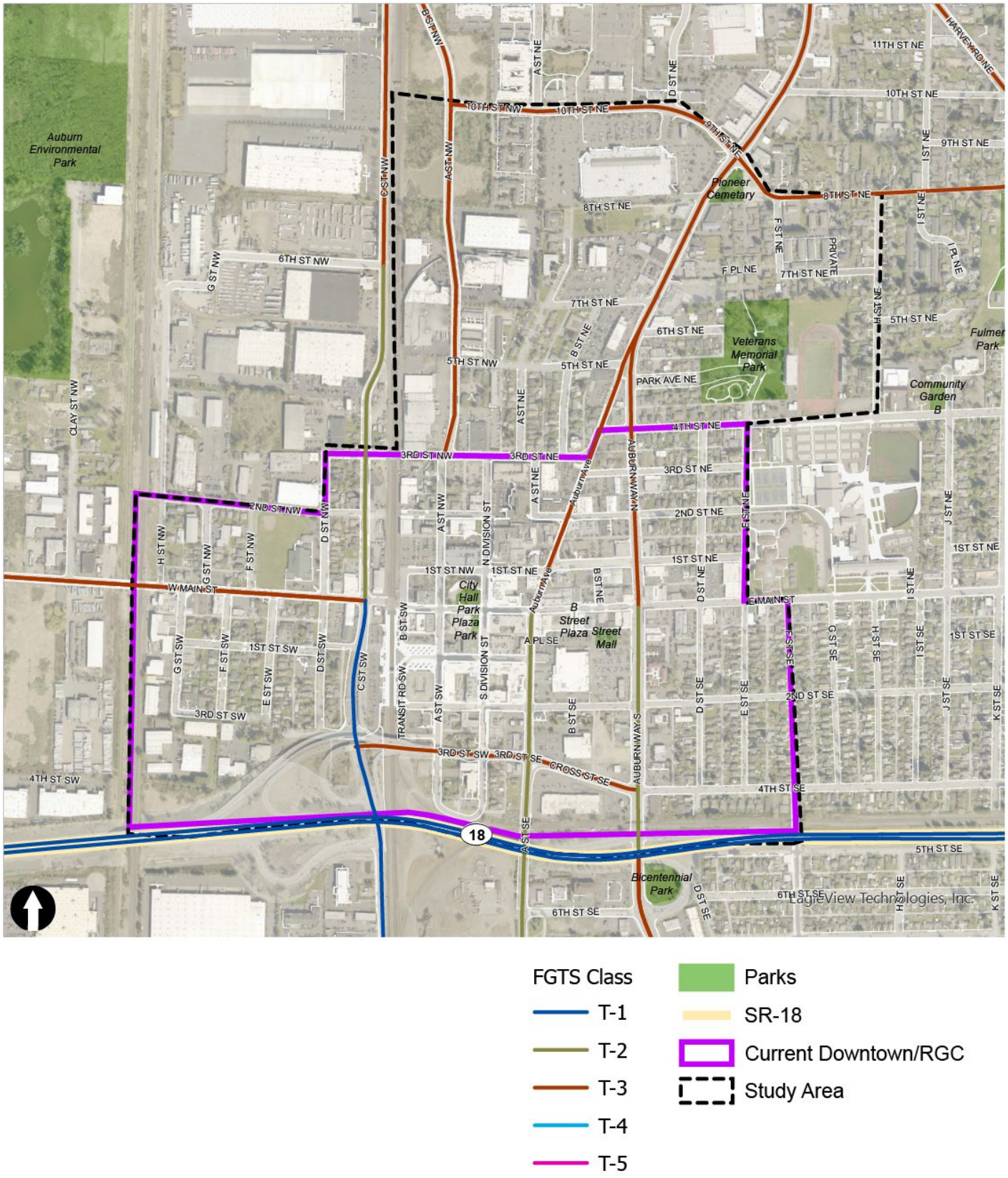


FIGURE 4-8 **Freight Network**

4.1.7 Rail

The Union Pacific (UP) Railroad and Burlington Northern Santa Fe Railway (BNSF) have rail lines running through Auburn, as indicated in Figure 4-9. The UP Railroad runs north–south along the western edge of the study area boundary. BNSF also runs north–south, has a triple track through downtown, and operates the rail yard between A Street SE and C Street SW, south of SR 18. This area may develop as a multimodal rail yard in the future, which could necessitate capacity improvements due to increased truck traffic. While the rail yard is outside the study area, future development could impact traffic flow through downtown. Finally, the Sounder runs through downtown Auburn on BNSF tracks, with the Auburn Transit station located downtown with one existing parking garage and a second parking garage undergoing planning development with a tentative completion date of 2027.



FIGURE 4-9 **Rail**

4.1.8 Relevant Studies

This section provides summaries of recent plans, programs, and studies related to the City of Auburn Downtown Subarea. These summaries provide a background understanding of the prior transportation planning and regulatory framework in the study area. Plans and studies are presented in chronological order, with most recent plans last.

AREA PLANS

Auburn Downtown Plan & EIS (2001)

The Auburn Downtown Plan was adopted in May 2001. The goal of the plan was to strengthen the downtown community, economy, and image by building on existing assets, facilitating catalyst projects in key locations, stimulating infill and redevelopment, and influencing the design and construction of high-quality public infrastructure. The vision of the downtown plan included key features to enhance transit accessibility, such as clearly identified wayfinding opportunities and maintaining historic railroad design.

The plan identified the Auburn Transit Center (Transit Center) as a key hub to providing connections to Main Street and the core retail area. The Transit Center, opened in 2000, is located in the heart of downtown Auburn, south of W Main ST, west of A ST SW, and east of C ST SW. The Transit Center houses a parking garage to help accommodate the parking needs of transit users. It is served by Sounder commuter rail, regional express bus, and several bus connections.

Also identified were challenges to mobility in the downtown area, including a need for enhanced mobility connections between downtown districts, as well as development of underutilized properties. A well-designed and defined pedestrian environment is also not present off of Main Street due to the presence of heavy

commercial, industrial, and auto-oriented uses. The plan also acknowledges the challenges that heavy freight traffic places on the walkability and desirability of downtown Auburn.

Comprehensive Downtown Parking Management Plan (2014)

The CDPMP manages existing parking assets, assesses current parking demand, forecasts future parking needs, and endeavors to develop a first-rate downtown parking system. The CDPMP was adopted in January 2014.

As of the 2014 plan, there were no considerations to expand the on- and off-street parking supply in the DUC. However, Sound Transit is planning to construct a second garage at the Auburn Transit Center. In 2022, Sound Transit hosted virtual engagement opportunities to determine the location of the garage. This construction project is estimated to be complete in 2027.

PROJECT-SPECIFIC PLANS

Auburn Station Parking and Access Improvements

Auburn Station is a train station served by S Line of the Sounder commuter rail network. It is located southwest of downtown Auburn and consists of two train platforms, a bus station, a parking garage, a public plaza, and a pedestrian bridge. Sound Transit is improving access to the Auburn Sounder Station for riders, whether they access the station by walking, bicycling, connecting buses or driving. This project includes a new parking garage located at 1st Street NW and is expected to be completed by 2027.

This parking garage will add parking as the existing Auburn Station parking garage is filled to capacity during the morning commute for riders using the Sounder S Line train travelling between Lakewood

and downtown Seattle. This train completes 13 roundtrips each weekday and runs special service for select events. Construction is expected to start as early as 2024 with opening to the public in 2027.

LOCAL JURISDICTION AND AGENCY PLANS

Auburn Comprehensive Plan – Transportation Element (2015)

The Auburn Comprehensive Plan was adopted in 2015 and recently updated in December 2021. Starting in summer 2022, the City of Auburn embarked on a major update to its Comprehensive Plan, last updated in 2015. This process is running concurrent to the analysis and planning work done for the 2024 Auburn Downtown Subarea Plan Update. The City coordinated the two planning efforts, and the Downtown Plan Update is central to helping the City meet the Comprehensive Plan's 2044 growth targets.

The plan as updated in December 2021 describes existing transportation conditions and future changes and needs as they relate to growth in the City. December 2021 updates included changes to the existing transportation network, an updated current needs evaluation, and identification of standards for future development and infrastructure improvement scenarios.

The Comprehensive Plan details anticipated land use development patterns and transportation capital needs citywide through 2044. The Comprehensive Plan identifies the following major transportation investments in downtown as summarized in Table 4-4.

TABLE 4-4 Transportation Investments in Downtown Auburn

Proposed Investment	Description
Auburn Way Corridor Improvements	Construct pedestrian accessibility and aesthetic enhancements on Auburn Way between 4th Street NE and 4th Street SE, including curb-bulbs at intersections adjacent to on-street parking, a new northbound left-turn at 3rd Street SE, and signal and channelization improvements at E Main Street.
Main Street TOD Infrastructure Improvements – Western Main Street	W Main Street, B Street NW/SW to Division Street, replace roadway, parking, sidewalks, and utilities.
Main Street TOD Infrastructure Improvements – Central Main Street	E Main Street, Auburn Avenue to Auburn Way N – replace roadway, parking, sidewalks, and utilities.
Main Street TOD Infrastructure Improvements – Eastern Main Street	E Main Street, Auburn Way to F Street SE/NE, replace roadway, parking, sidewalks, and utilities.

TOD = Transit-Oriented Development

Puget Sound Regional Council VISION 2050 (2021)

The City of Auburn Downtown Subarea is identified in PSRC's VISION 2050 plan as a Regional Growth Center (RGC) intended to accommodate a significant share of future growth. To achieve regional growth goals, Auburn should encourage development near high-capacity transit stations and within RGCs.

2024–2029 Transportation Improvement Program (2023)

The City of Auburn Transportation Improvement Program (TIP) was adopted in June 2023; it sets priorities for the allocation of secured and unsecured funding and coordinates future transportation projects with needed utility improvements. Projects in the TIP that

fall within the Downtown Subarea study boundary are included below:

- I-7: Downtown Infrastructure Improvement Project: The purpose of this project is to construct infrastructure improvements in downtown Auburn that will support existing development and future redevelopment activities and to replace infrastructure that is at or near the end of its useful service life. This project will design and construct street and utility improvements in the alley along the north side of the Auburn Avenue Theater building, Auburn Avenue from the alley to E Main Street, and on E Main Street from Auburn Avenue to the B Street Plaza. The project includes replacing the existing traffic signal at the intersection of E Main/Auburn Avenue, installing decorative overhead street lighting on E Main Street and the B Street Plaza, replaced sidewalks on E Main Street, sewer and water utility main construction, and other work to improve and enhance the project area.
- I-15: 10th Street NW/A Street NW Intersection Improvements – New Signal: The project will construct a new traffic signal in place of the existing stop-control on the 10th Street NW approach. The project is needed to address an LOS deficiency at the intersection. The project will also evaluate intersection control, channelization, and pedestrian crossing improvements along 10th Street NW to the east of the intersection.
- N-5: 1st Street NE/NW and Division Street Pedestrian Improvements: The project will implement non-motorized improvements at the 1st Street NE/NW/N Division Street intersections in downtown Auburn. The proposed improvements will create a raised intersection to reduce speeds, and encourage motorists to yield to pedestrians using the crosswalks; add curb bulbs where they are not currently provided to reduce crossing distances and improve pedestrian visibility; construct new Americans with Disabilities Act (ADA) complaint ramps; and both pedestrian-level and street lighting improvements.
- P-3: 10th Street NE Preservation: The project will preserve 10th Street NE between B Street NW and Auburn Way N. The project

will also rechannelization the roadway to convert the existing four-lane cross-section to a three-lane section incorporating bike lanes and a center two-way left-turn lane. The existing intersection control at the intersection with A Street NE will be revised to remove the east/west stop-control, and the installation of a new north/south crosswalk to the east of the intersection. The new crosswalk is proposed to be enhanced with a median island and a Rectangular Rapid Flashing Beacon (RRFB). The existing signal at D Street NE will require modification to match the new roadway cross section.

- R-5: A Street NW, Phase 2 (W Main Street to 3rd Street NW): The project will widen A Street NW to create a three-lane roadway section between W Main Street and 3rd Street NW. This project will improve the connection between the A Street NW Extension (Phase 1) and Auburn Station and Central Business District. The project is approximately 0.2 mile long.
- R-16: Regional Growth Center Access Improvements: The project will construct a northbound left-turn lane and a northbound/southbound crosswalk at the 3rd Street NE/Auburn Avenue intersection, and realign the 4th Street NE/Auburn Way N intersection to eliminate the split phase signal operation, improving circulation and access. The project will improve traffic operations, safety, and circulation for both vehicles and non-motorized users.

City of Auburn Local Road Safety Plan (2022)

The City of Auburn Local Road Safety Plan was adopted in March 2022 and summarizes a systemic safety analysis of Auburn's citywide transportation network. The plan found that factors such as high-speed roadways (with posted speeds greater than 35 miles per hour), widely spaced street lighting, the presence of industrial land uses, streets with higher functional classifications, and alcohol/drug use are all contributing factors to the most to serious or fatal collisions in Auburn. Within the downtown study area, Auburn Way was found to have the highest collision risk factors for serious or fatal collisions.

East Main Street Traffic Analysis (2024)

The 2024 East Main Street Traffic Analysis recommends changing traffic patterns along E Main Street to provide more space for people walking and biking and promote commercial activity along this key business corridor. The City conducted a preliminary traffic analysis of modifying E Main Street from Auburn Avenue to Auburn Way. Four options were studied in the analysis:

- Option 1 – Keep the road in its existing two-way traffic configuration.
- Option 2 – Close the road to all vehicle traffic.
- Option 3 – Close the road to eastbound traffic.
- Option 4 – Close the road to westbound traffic.

All scenarios utilized the 2044 Draft-Preferred Land Use Alternative Scenario (2044 Land Use) from the City's Draft Comprehensive Plan Update as the background traffic demand model, which is also consistent with the methodology used for this Draft EIS. This preliminary traffic analysis shows that, from a traffic operations perspective, Options 1 and 3 are feasible. However, a more detailed traffic analysis would be required prior to implementation of any changes.

4.2 Impacts

4.2.1 Impacts Common to All Alternatives

This section evaluates future transportation conditions under three alternatives: Alternative 1, No Action; Alternative 2, Moderate Growth; and Alternative 3, High Growth. Alternative 1 represents the expected growth under existing zoning and laws if the City were to make no changes to the 2021 Downtown Plan. Alternative 2 assumes moderate growth in the study area that is somewhat higher

than with Alternative 1. Finally, Alternative 3 represents the highest growth in the study area. Chapter 3, Section 3.2.1, of this EIS presents detailed land use assumptions for Alternative 1, Alternative 2, and Alternative 3.

This analysis identifies future-year deficiencies, as well as locations where either Alternative 2 or 3 would impact the transportation system in 2044 compared to Alternative 1. **Table 4-5** represents projects in downtown Auburn that are expected to be constructed by 2044 and thus are assumed for all three future-year alternatives.

TABLE 4-5 **2044 Future Project List for Downtown Auburn**

Proposed Project	Description
A Street Loop	Construct a new one-way (eastbound) roadway connection between A Street SW/S Division Street and A Street SE
3rd Street NE/Auburn Avenue	Construct a northbound left-turn lane and a northbound/southbound crosswalk at the 3rd Street NE/Auburn Avenue intersection and realign the 4th Street NE/Auburn Way N intersection to eliminate the split-phase signal operation.
Auburn Way S/6th Street SE	Construct a dedicated southbound right-turn pocket on Auburn Way S at 6th Street SE and other improvements to support the new right-turn pocket.
10th Street NE Non-Motorized Improvements	Convert the existing four-lane cross-section to a three-lane section with bike lanes and a center two-way left-turn lane and changes to the existing intersection control at the intersection with A St NE.

TRAFFIC OPERATIONS ANALYSIS

Traffic operations were analyzed using Synchro 11 software. The existing Synchro network was updated to reflect roadway modifications planned to be in place by 2044 (identified in Table 4-5) as well as the forecasted vehicle volumes under each alternative. Signal phase timings for 2044 were optimized based on the projected future-year vehicle volumes. The signal timings were kept consistent between Alternative 1, Alternative 2, and Alternative 3.

SHORT-TERM CONSTRUCTION IMPACTS

Redevelopment would occur under all three alternatives. During redevelopment, localized and temporary construction impacts could impact transportation in the immediate vicinity of a project site, for example a sidewalk closure or increased truck traffic. The City will manage such temporary uses through their street use permit process. As a result, **the short-term (construction) impacts are assumed to be less-than-significant**.

LONG-TERM IMPACTS

Long-term impacts are explored for Alternative 1, Alternative 2, and Alternative 3 below.

4.2.2 Impacts of the No Action Alternative

Alternative 1, No Action, serves as the baseline for the impact analysis of the development alternatives (Alternatives 2 and 3). Conditions may change in the future but they would not be triggered by changes suggested in Alternatives 2 and 3 of this analysis. Alternative 1 represents the operations of the transportation system if no actions were taken by the City Council

and no zoning changes were made in the study area as part of the Downtown Subarea Update.

THRESHOLDS OF SIGNIFICANCE

The following definition is used to identify significant impacts under Alternative 1:

- Vehicle LOS below the LOS standard at a study intersection.

ANALYSIS RESULTS

The following section describes the results of the evaluation of transportation conditions under Alternative 1. Transit impacts are discussed qualitatively. As defined above, this Draft EIS identifies impacts if future transportation operations are not expected to meet the City's adopted LOS standards.

Intersection LOS

Table 4-6 summarizes the average vehicle delay for each study intersection/corridor compared to its LOS standard in the PM peak hour. By 2044, traffic volumes would increase due to the land use growth that would occur within downtown Auburn and other parts of the City as well as regional growth not associated with Auburn. Therefore, delay at most intersections is expected to increase to some degree. Operations at two intersections would fall below the City's standard:

- C Street SW & 3rd Street NW – LOS F
- A Street NE & 10th Street NE – LOS E

Figure 4-10 shows intersection operations, in terms of LOS for Alternative 1. Note that colors represent LOS grades, not whether operations meet the City's standard.

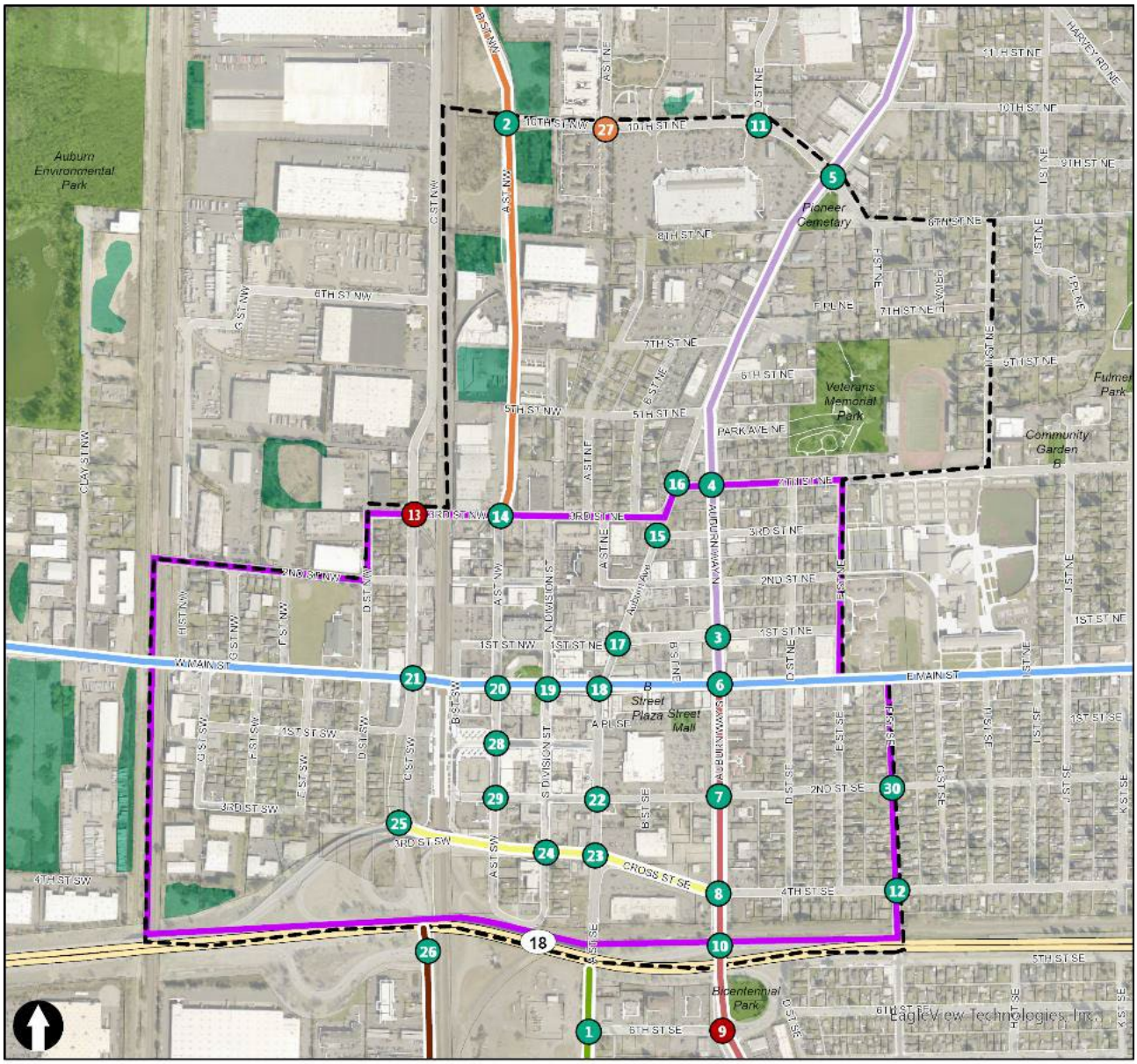
TABLE 4-6 2044 Alternative 1, No Action, PM Peak Hour Corridor Level of Service and Delay

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS						
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C / 24	C / 24
		4	Signal			
		5	Signal			
		6	Signal			
3	Auburn Way S from E Main St to M St SE	7	Signal	D	C / 28	D / 38
		9**	Signal			
		6	Signal			
		8	Signal			
		10	Signal			
10	Auburn Ave/A St from 6th St SE to E Valley Access Rd	1**	Signal	D	A / 9	B / 11
11	Main St from West Valley Hwy to R St	18	Signal	D	C / 20	C / 23
		19	Signal			
		20	Signal			
		6	Signal			
		21	Signal			
13	C St SW from Ellingson Rd to SR 18	25**	Signal	D	B / 19	C / 22
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC	D	C / 22	C / 21
		14	Signal			

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to AWS	23	Signal	E	B / 19	C / 23
		24	Signal			
		8	Signal			
		25	Signal			
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS						
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B / 19	B / 19
N/A	F St SE & 4th St SE	12	Signal	E	B / 15	B / 19
N/A	C St SW & 3rd St NE	13	Signal	E	F / 90	F / >120
N/A	Auburn Ave & 3rd St NE	15	Signal	E	B / 14	B / 12
N/A	Auburn Ave & 4th St NE	16	Signal	E	A / 4	A / 4
N/A	Auburn Ave & 1st St NE	17	Signal	E	A / 9	B / 12
N/A	A St SE & 2nd St SE	22	Signal	D	C / 30	C / 30
N/A	10th St NE & A St NE	27	TWSC	D	B / 11	E / 40
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC	D	A / 8	B / 10
N/A	A St SE & 2nd St SE	29	Signal	D	B / 13	B / 18
N/A	F St SE & 2nd St SE	30	AWSC	D	A / 8	A / 8

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan



Note: Downtown Urban Center area shown on this map is consistent with the Current Downtown/ RGC area shown on other maps. The Downtown Auburn Boundary shown on the map and legend refers to the study area.

FIGURE 4-10 Intersection Level of Service PM Peak Hour – Alternative 1, No Action

Transit

In 2044, King County Metro will operate a new RapidRide route in Auburn. The proposed route is prepared to launch in 2026 and will run north/south through Auburn, with a starting point at Auburn Station and terminus in the Renton Transit Center. The route will run primarily along Auburn Way N.

King County Metro Route 181 is under consideration for a future RapidRide, within the agency's interim network, and will likely be a RapidRide line before 2044. The agency is currently evaluating the potential RapidRide lines in the interim network and will make a decision in 2024 as to which line will move into the planning phase next. Route 181 connects the Federal Way Transit Center to the Auburn Transit Center and Green River College, serving the Lea Hill area of Auburn.

The failing performance at C Street SW & 3rd Street NE, under Alternative 1 could impact transit operations.

4.2.3 Impacts of Alternatives 2 and 3

The development alternatives (Alternatives 2 and 3) are evaluated against Alternative 1 to identify transportation impacts. This approach compares the changes in the transportation system expected to result from Alternatives 2 and 3 against transportation changes expected under Alternative 1.

THRESHOLDS OF SIGNIFICANCE

The following definition is used to identify impacts for Alternatives 2 and 3:

- Vehicle LOS below the LOS standard at a study intersection.

2044 ALTERNATIVE 2 RESULTS

Alternative 2, Moderate Growth, was assessed for this EIS. In 2044, growth under Alternative 2 is expected to be moderate and less intense than growth in Alternative 3. Therefore, the number of impacts would be less than or equal to Alternative 3.

Since Alternative 3 has a significant adverse impact, it is conservatively expected that Alternative 2 would also have a significant adverse impact.

2044 ALTERNATIVE 3 RESULTS

Table 4-7 summarizes the average vehicle delay and LOS for each study intersection compared to the existing conditions and Alternative 1 results. Figure 4-11 summarizes the LOS for each study intersection under Alternative 3. Under Alternative 3, land use growth would result in increased vehicle volumes compared to Alternative 1. Results and impacts are evaluated in comparison to existing conditions and Alternative 1.

One significant adverse traffic operation impact is expected under Alternative 3 (and shown in **bold** in Table 4-7):

- C Street SW & 3rd Street NW – LOS F exacerbated

This intersection is signalized. Vehicles experience excessive queuing when traveling eastbound along 3rd Street NW in the PM peak due to higher volumes and delay along the rail line. Because this intersection is located along a Sound Transit express route that runs frequent service in the PM peak period, it is considered to have significant auto and transit impacts.

A review of traffic operations shows a similar deficiency under Alternative 1. Potential measures to mitigate the impact on the impacted intersection are presented in the *Mitigation Measures* section.

TABLE 4-7 2022 Downtown Auburn Corridor Level of Service

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)	2044 Alternative 3 LOS/Delay (seconds)
INTERSECTIONS ALONG DESIGNATED CORRIDORS							
2	Auburn Way N from E Main St to 15th St NE	3	Signal	E	C / 24	C / 24	C / 30
		4	Signal				
		5	Signal				
		6	Signal				
3	Auburn Way S from E Main St to M St SE	7	Signal	D	C / 28	D / 38	D / 38
		9**	Signal				
		6	Signal				
		8	Signal				
		10	Signal				
10	Auburn Ave/A St from 6th St SE to E Valley Access Road	1**	Signal	D	A / 9	B / 11	A / 14
11	Main St from West Valley Hwy to R St	18	Signal	D	C / 20	C / 23	D / 36
		19C	Signal				
		20	Signal				
		6	Signal				
		21	Signal				
13	C St SW from Ellingson Rd to SR 18	25**	Signal	D	B / 15	C / 22	C / 20
18	A St NW/B St NW from 3rd St NE to S 277th St	2	TWSC	D	C / 22	C / 21	C / 35
		14	Signal				

Corridor ID	Location	Intersection ID	Control Type	LOS Standard*	2022 Average LOS/ Delay (seconds)	2044 Alternative 1 Average LOS/Delay (seconds)	2044 Alternative 3 LOS/Delay (seconds)
31	3rd St SW/Cross St from C St to AWS	23	Signal	E	B / 19	C / 23	C / 31
		24	Signal				
		8	Signal				
		25	Signal				
INTERSECTIONS OUTSIDE OF DESIGNATED CORRIDORS							
N/A	10th St NE/9th St NE & D St NE	11	Signal	D	B / 20	B / 19	C / 24
N/A	F St SE & 4th St SE	12	Signal	E	B / 15	B / 19	C / 28
N/A	C St SW & 3rd St NE	13	Signal	E	**F / 90**	**F / >120**	**F / >120**
N/A	Auburn Ave & 3rd St NE	15	Signal	E	B / 14	B / 12	B / 15
N/A	Auburn Ave & 4th St NE	16	Signal	E	A / 4	A / 4	A / 5
N/A	Auburn Ave & 1st St NE	17	Signal	E	A / 9	B / 12	C / 22
N/A	A St SE & 2nd St SE	22	Signal	D	C / 30	C / 30	D / 43
N/A	10th St NE & A St NE	27	TWSC	D	B / 11	E / 40	D / 33
N/A	A St SW & Transit Driveway/1st St SW	28	AWSC	D	A / 8	B / 10	B / 12
N/A	A St SE & 2nd St SE	29	Signal	D	B / 13	B / 18	B / 18
N/A	F St SE & 2nd St SE	30	AWSC	D	A / 8	A / 8	A / 9

* Corridor segments within downtown Auburn may operate at LOS E in accordance with the 2001 Auburn Downtown Plan. All other arterial and collector corridors must operate at LOS D or better, unless otherwise indicated.

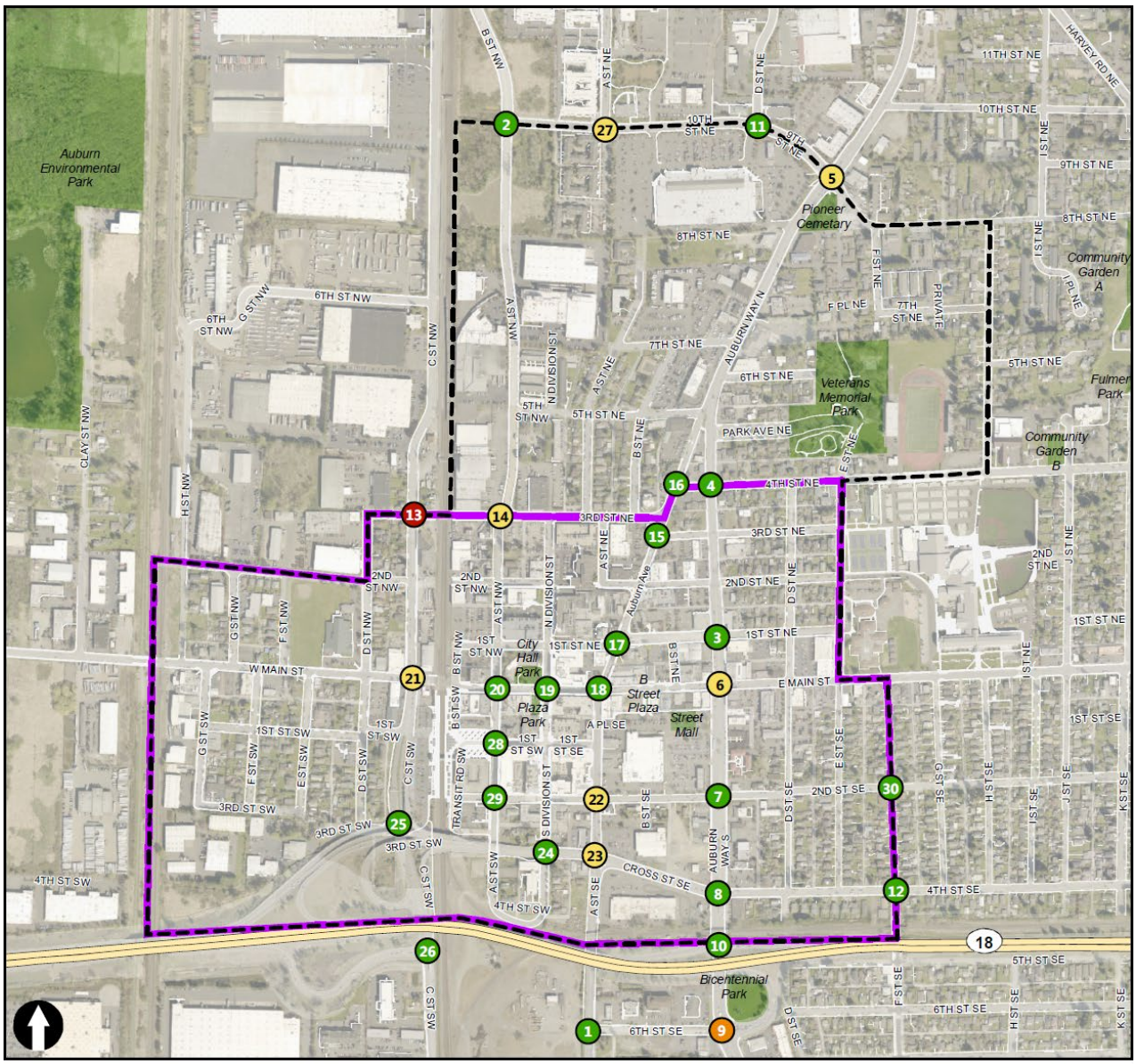
** Study intersections fall outside of the downtown boundary but were included in analysis for the 2001 Auburn Downtown Plan.

Transit

Sound Transit Route 566 runs north/south along C Street NW, which includes the impacted intersection in Alternative 3. The increased delays will impact this transit route in addition to vehicles. As a result, Alternative 3 would have a **significant impact on transit operations**.

4.2.4 Summary of Impacts

Figure 4-10 above and **Figure 4-11** below represent the intersection LOS results for Alternative 1 and Alternative 3, respectively. Please note that the colors represent intersection operations, in terms of LOS grades, not whether the intersection meets the City's standard.



Note: Downtown Urban Center area shown on this map is consistent with the Current Downtown/ RGC area shown on other maps.

Alternative 3 LOS

- A - C
- D
- E
- F
- Study Area
- Downtown Urban Center
- SR-18
- Parks

FIGURE 4-11 Intersection Level of Service PM Peak Hour – Alternative 3, High Growth

4.3 Mitigation Measures

This section identifies a range of potential mitigation strategies that could be implemented to reduce significance of adverse impacts identified in the previous section for 2044 Alternative 3.

4.3.1 Incorporated Plan Features

The City could make changes to signal operations at C Street NW and 3rd Street NW. Currently, the signal operates only with protected permitted phasing when the rail crossing is activated; otherwise, it operates with permitted left-turn phasing. If the signal were updated to protect permitted left-turn phasing during peak periods, the LOS results show a D, which is acceptable under the City's LOS standards. This signal phasing update would also reduce the identified transit impact.

4.4 Significant Unavoidable Adverse Impacts

With some combination of the potential mitigation measures outlined in the previous chapter, all impacts could be mitigated to a less-than-significant level. Therefore, **no significant and unavoidable adverse impacts on transportation are expected**.

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CHAPTER 5 Distribution List

The Draft EIS has been issued with a notice of availability, consistent with Washington Administrative Code (WAC 197-11-455), including distribution to the following:

TRIBAL AND FEDERAL AGENCIES

- Federal Emergency Management Agency
- Muckleshoot Indian Tribe Environmental Department Fisheries Office, Planning, Cultural Program, Fisheries Division
- U.S. Army Corps of Engineers, Seattle District Regulatory Branch
- U.S. Department of Agriculture Natural Resources Conservation Service

REGIONAL AND COUNTY AGENCIES

- Auburn School District
- King County Area Developer Services, Department of Natural Resources, Department of Permitting and Environmental Review, Environmental Health Division, Local Services, Metro, Waste Division, Wastewater Treatment Division
- Lakehaven Utility District Development Engineering
- Lake Meridian Water District

- Pierce County Master Builder Association
- Pierce Transit, Land Use Review Capital Development
- Puget Sound Clean Air Agency
- Puget Sound Regional Council
- Soos Creek Water and Sewer District
- Sound Transit
- South King Housing and Homelessness Partners

STATE OF WASHINGTON

- Department of Archaeology and Historic Preservation
- Department of Commerce
- Department of Ecology
- Department of Fish and Wildlife
- Department of Health
- Department of Natural Resources
- Department of Social and Health Services Land and Buildings Division
- Department of Transportation

CITY OF AUBURN, AUBURN SERVICE PROVIDERS, ADJACENT CITIES

- City of Algona
- City of Bonney Lake Planning and Community Development
- City of Federal Way Community Development
- City of Kent Planning Department
- City of Kent School District
- City of Pacific Community Development

OTHER INTERESTED PARTIES

- Alpine Ridge Insurance Agency
- Washington Environmental Council
- Futurewise
- Rainier Audubon
- King County and Snohomish County Master Builder Association

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EXHIBIT 4

CITY OF AUBURN
DOWNTOWN SUBAREA PLAN & PLANNED ACTION EIS

BASELINE REPORT

DRAFTED DECEMBER 2022

(PARTIALLY UPDATED SEPTEMBER 2024)

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KEY TAKEAWAYS

This document is an early step in the planning process and is intended to describe existing conditions in the study area. Topics addressed in this report include:

Land Use
Urban Form
Natural Environment
Housing and Socioeconomics
Economics
Transportation
Public Services
Utilities and Stormwater

While each chapter in the report explores a unique aspect of the study area, some recurring themes cut across chapters. A short summary of these overarching themes and key findings associated with each of the topics is included below.

Overall Themes

Expanding Downtown. The existing regional growth center (RGC) boundary will likely meet current and future target activity levels required by PSRC. Expanding the Regional Growth Center (RGC) to include the entirety of the Downtown Study Area meets current minimum PSRC activity unit targets but will likely not meet future targets under a "No Action" scenario. However, the expanded study area provides more opportunities for concentrated growth in Regional Centers, following the PSRC VISION 2050 framework, that could allow the City to meet targets through moderate or high rezoning.

Mix of interests and activities. Recent development has started to revitalize downtown, but more work is needed to make it a mixed-use urban center. The need for more things to do downtown and a focus on making the area feel welcoming and safe was common feedback from early engagement with stakeholders and community members.

Multimodal Access – challenges and opportunities. Multimodal access challenges include limited separated bike infrastructure, wide arterial streets with long crosswalks, and streets with five-foot-wide sidewalks that may or may not have a planter strip. Planned RapidRide service along Auburn Way N will provide opportunities to improve transit access.

Main Street Corridor. Main Street corridor is unique within Auburn and an asset to the overall downtown area. Programs to help property owner's improve facades and make building improvements could help continue the revitalization of the area. The area also has many existing small businesses that have struggled to find affordable retail space in newer buildings in the area.

MultiCare Hub. The MultiCare Auburn Medical Center (MultiCare) is a major employer and anchor within Downtown Auburn. Future expansion plans may continue to develop this hub within downtown.

Displacement Risks. PSRC has indicated elevated risks of displacement within the study area and a diverse overall community. Commercial displacement risk may also be a challenge for some existing businesses.

West Downtown. West Downtown area has been considered part of downtown in past planning cycles, but there are both access and market challenges for significant future development. Plan should consider what is feasible in this area in terms of growth and density and if it is included in the RGC. (See .

for a map of how the plan defines subdistricts within the study area.)

North Downtown. Expanding to the north downtown area could allow for Transit-Oriented Development (TOD) opportunities around upcoming Rapid Ride line. There are some large parcels and development opportunities in that area. (See .

on page 3-5 for a map of how the plan defines subdistricts within the study area.)

Arts and Cultural Public Investments. City's emerging plans for new opportunities at the current Arts and Cultural center and the Auburn Ave Theater properties could be a helpful theme to support revitalization efforts in the Main Street Corridor area.

Land Use

- The Downtown Urban Center (DUC) zone already applies to much of the DUC area (current RGC boundary). North Downtown offers opportunities for increasing density to bring in more mixed-use development.
- There are pockets of auto-oriented commercial areas that could provide opportunities for higher-density development.
- There are pockets of residential uses in some locations within the study area, which will need to be carefully assessed for displacement risk.
- The city-owned Auburn Avenue Theater and former Max Apartments site presents a significant opportunity for the city, as the vision is to recreate a theater along with arts-focused ancillary development. Implementation of this type of project can be complex and sometimes challenging, so ongoing planning may be needed to realize this vision.
- Other city-owned properties, such as surface parking lots, could offer additional sites for new development, or could continue to serve as surface parking. These property assets will enable the City to play a significant role in guiding Downtown's development in the coming decades, through renovations, modifications, and/or major redevelopment projects.
- There are a number of large and mid-size commercial properties in downtown that could redevelop within the timeframe of this plan.

Urban Form

- There is very little open space and tree canopy cover in the study area (except for some in residential areas and Veterans Memorial Park.) Downtown would benefit from more green open space and access to shade to reduce urban heat.
- Downtown has limited separated bicycle infrastructure and many arterial streets have minimum five-foot-wide sidewalks without planter strips.
- Redevelopment of Downtown Core is delivering a strong pedestrian built environment.
- Plan should explore opportunities to increase activation through groundfloor commercial uses, events, creative streetscape uses/programs, and/or linking of public space and streetscape improvements.
- There are several retail spaces in newer developments that have been slower to fill, leaving vacant groundfloor spaces at the street level.

- Arts and culture is a resonant theme within the community and could help support further revitalization, particularly between along the Main Street corridor.

Natural Environment

- There are wetlands present on highly developed properties within the study area. These natural elements could provide an opportunity to enhance ecological conditions in the subarea, if the plan explores redevelopment and new land uses adjacent to these areas.
- Downtown Auburn does not appear to be at elevated risk from riverine flooding, though stormwater flooding may present some challenges.
- Air pollution sources from arterial and rail corridors should be considered when locating new housing.
- Highly developed context of downtown Auburn limits natural environment processes within the study area. Redevelopment could offere opportunities for green stormwater infrastructure, urban trees canopy cover, parks and green open spaces, and other elements of green infrastructure.
- Urban heat is a challenge for the Downtown area. Lack of shade lead to higher temperatures, which can be very challenging for vulnerable populations (seniors, low-income, etc.)

Housing and Socioeconomics

- Auburn's population has grown significantly since the 1980s. PSRC forecasts a population increase of about 20 percent for the next two decades in Auburn.
- Auburn's downtown has smaller household sizes, smaller than shares of family households and a larger share of renters than the city overall, typical of downtown patterns nationally.
- The population of the downtown study area is significantly older than the citywide population and contains a number of large senior housing developments.
- About a quarter of downtown housing units in the study area are single-family homes, and a third of housing units are in large developments of 50 units or more.
- The downtown study area population is classified by PSRC as having moderate to high risk of displacement due to redevelopment.
- Auburn is a historically blue-collar city and the majority of jobs and of job growth in the past 20 years has been in manufacturing, though few of these jobs are in the downtown area. The downtown area accounts for around 9 percent of all jobs in the city.
- Retail jobs make up the largest share of jobs in the study area, at 21.6 percent. The health care sector accounts for another 20.5 percent of downtown jobs, and MultiCare is the largest employer in the study area with 635 employees.
- The majority of employees in downtown Auburn do not live in the downtown area.

Economics

- Development in downtown Auburn has taken place within a small part of the downtown core, and the majority of the development has been housing over some ground floor commercial space.
- Although information and technology jobs are growing the fastest, driven by Seattle's dominance in tech industries, health care and government are both expected to add significant numbers of jobs in the coming years regionally. Auburn's existing cluster of medical facilities makes the downtown well positioned to take advantage of this regional trend.
- Most new retail uses will likely occupy existing space in historic buildings, new ground floor space in mixed-use developments, and adaptive reuse projects.
- Various incentives or programs may be appropriate to help reduce retail vacancies downtown and help catalyze more activity in the area, such as a commercial vacancy tax, and continued funding for the Business Improvement Association. One key tool is the city's Downtown Façade Improvement Grant Program, which should continue into the future and potentially be provided with more funding in order to be applied to a wider range of buildings and projects. One focus area of this tool should be Historic Main Street.
- Opportunity locations for redevelopment in the downtown include several blocks in the downtown core east of the most recent developments and a cluster of underutilized sites in the north subarea south of Fred Meyer, near the forthcoming BRT line.

Transportation

- As the City of Auburn updates the Comprehensive Plan to reflect a 2044 future year, the Downtown subarea will receive subsequent updates. There are several projects in and around the downtown subarea, such as the Sound Transit construction of a new parking garage to accommodate demand around the Sounder rail line. Additionally, plans in the vicinity of the downtown subarea will impact traffic needs in and around the study area.
- The downtown subarea has adequate sidewalk presence, but sidewalks are varying in age and conditions. There is limited separated bicycle infrastructure in the City, but the downtown area is in proximity to regional trails. There are also principal and minor arterials and freight rail lines running through the study area boundary From a safety perspective, the city-wide Local Road Safety Plan found that a large number of collisions occur along principal and minor arterial roadways at major intersections.
- The City does not administer transit service. Transit service is provided through Sound Transit, King County Metro Transit, Pierce Transit, and Muckleshoot Tribal (MIT) Transit. The City also has Sounder rail service, operating on the north/south BNSF rail line.
- Finally, parking is offered through on-street public parking, off-street public parking, and off-street private parking.

- Currently, all intersections that fall within the downtown study area boundary operate at a Level of Service D or better, with the exception of one intersection (C St NW & 3rd St NW) operating at LOS F in the PM peak.

Public Services

- Public services that cover Downtown also serve areas beyond the study area. Public Services located within the study area are listed in this report. Future service needs will be assessed and identified in the City's 2024 Comprehensive Plan Update.
- There are two public high schools and one public elementary school located in or adjacent to the study area.
- There is already a need for new fire station that serves the Downtown area. Further development downtown may increase the need for that public service.
- The existing police station is planned to be moved elsewhere outside of downtown by 2044.
- The city's 2015 Park and Recreation Open Space Plan indicated Downtown as needing more open space, a finding that aligns with Urban Form section of this report.

Utilities and Stormwater

- Water service in the general downtown area is noted by staff as having existing and future capacity issues, which are being evaluated in an updated Water Services Plan and projects incorporated into the 2044 periodic comprehensive plan.
- Sewer lines run in alleyways throughout much of the downtown area, which can limit the type and size of development that can occur without moving these facilities.
- The City has regulations that must be adhered to in terms of utilities and stormwater. The City's Storm Drainage Utility coordinates the City's municipal NPDES permit compliance efforts and leads efforts to manage flooding in the City. In order to effectively plan for future activities and improvements for the storm drainage system, the City has undertaken comprehensive planning efforts specific to stormwater management that go beyond regulatory compliance.
- The City identifies the northeastern part of the Downtown study area – generally east of Auburn Ave. and north of Main St. – as within the City's Groundwater Protection Zone 1, where infiltration of stormwater runoff from pollutant generating surfaces is not allowed without enhanced treatment and approval from the City engineer, per the City's SWMM.
- Proposed development and growth should take into consideration potential adverse impacts to stormwater from potential increases in impervious surface.
- Public utilities should be upgraded and increased as necessary to accommodate growth and development.
- Attention to proper monitoring of water quality is crucial to public health and safety.

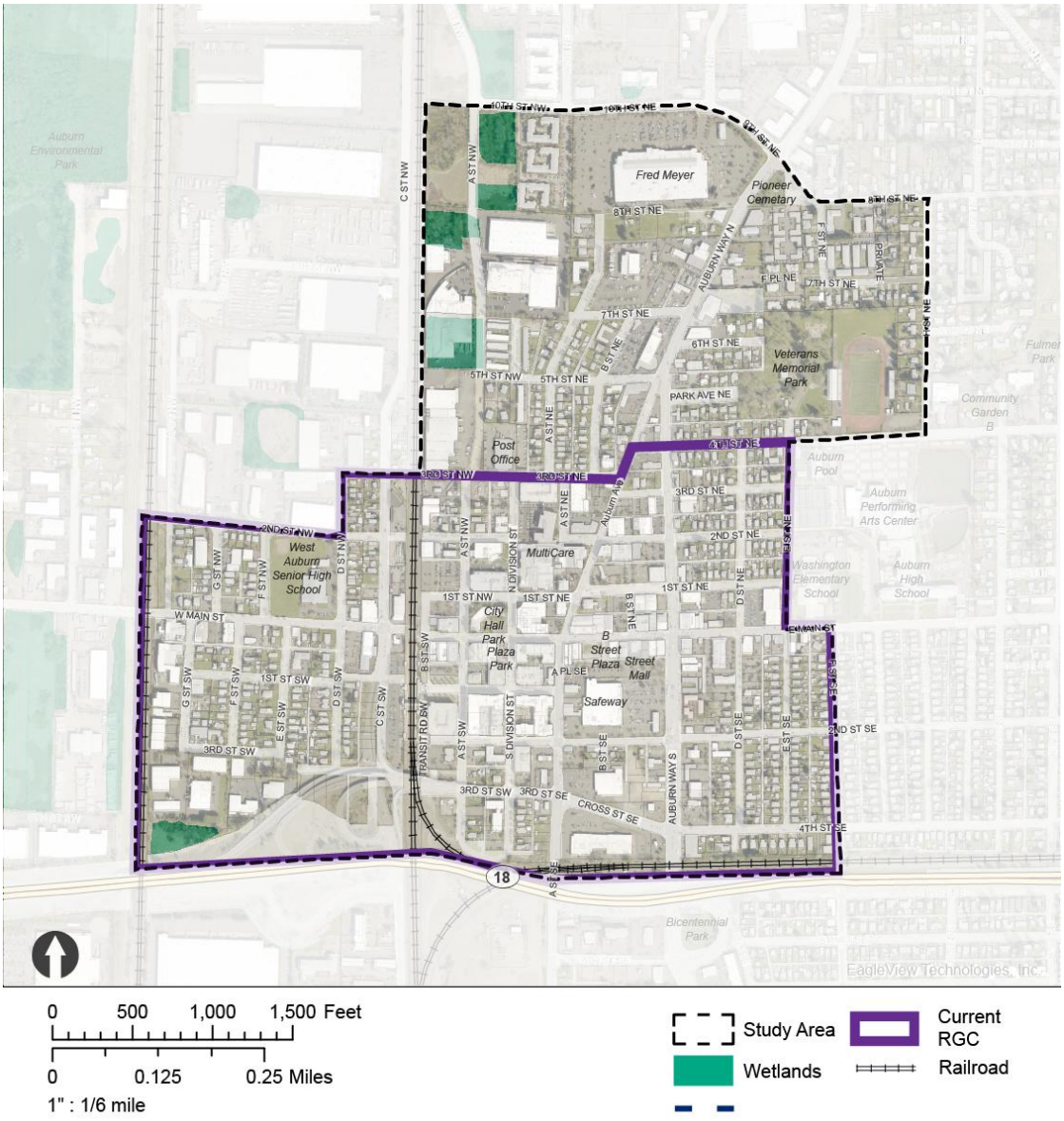
SECTION 1 INTRODUCTION

1.0 What Is the City of Auburn Downtown Subarea?

The City of Auburn Downtown Subarea is a unique and diverse area that includes a mix of land uses, sub-neighborhoods, and architectural styles. The Downtown Urban Center (DUC) zone applies to much of the DUC area and was intended to create a strong identity for downtown Auburn. The DUC also aligns with the Puget Sound Regional Council's (PSRC) Regional Growth Center area. The City of Auburn was first designated a regional growth center in 2003, and is now considered an Urban Growth Center, following the PSRC's Regional Centers Framework Update in 2018.

This Downtown Plan Update proposes a larger study area so that this plan may assess whether expanding the downtown to the north provides the City with new opportunities for residential and commercial growth while aligning with regional transportation investments. This new study area, which is 376 acres total, includes the DUC boundary, but expands to the north to 10th St NE and 8th St NE. The BNSF/Sounder rail corridor comprises the western border while the eastern border is defined by H St NE, 4th St NE, and E St NE.

FIGURE 1-1 Study Area Map



SOURCES: MAKERS (City of Auburn GIS data).

1.1 What Is the Subarea Plan?

The previous Auburn Downtown Plan & EIS was adopted in 2001 and has provided the framework for development of the City's downtown for the past 20-years. The document is now reaching the end of the planned time period and the City has also changed over that time. The revised Auburn Downtown Plan is envisioned to supplement the existing plan by providing a refreshed perspective of the land use, development, and transportation options serving the

downtown area. The City is also pursuing a Planned Action EIS with this project to streamline permitting and encourage more development within the downtown subarea.

1.2 What Is in This Report?

This document is an early step in the planning process and is intended to describe existing conditions in the study area. Topics addressed in this report are listed below. It should be noted that the order of topics in this report is based on the SEPA elements of the environment as listed in WAC 197-11-444.[1] This was done for convenience only and does not reflect importance or relative priority of any of the topics.

Natural Environment
Land Use
Urban Form
Housing and Socioeconomics
Economics
Transportation
Public Services
Utilities and Stormwater

The information in this report was compiled from existing available data and research findings; primary research was not conducted as part of this effort.

It is anticipated that this report will continue to be updated and revised as additional information is identified during the planning process. Ultimately, information in this report will help inform the future subarea plan.

A short summary of overarching themes and key findings associated with each of these topics is included in the section preceding this introduction. The balance of this report contains more detailed discussion of existing conditions for each topic area.

[1] The Urban Form and Economics are not specifically identified as SEPA elements of the environment and have been inserted near related topics.

SECTION 2 LAND USE

This chapter describes existing land use patterns, development types, mix of uses, scale and intensity of development, urban form, and land use compatibility. It also summarizes pertinent plans, policies and regulations, including the City's GMA Comprehensive Plan, land use and shoreline regulations, Puget Sound Regional Council requirements, and other applicable and adopted plans from the City of Auburn.

2.0 Existing Policies and Regulations

Local Policy Framework

CITY OF AUBURN COMPREHENSIVE PLAN

At the time this plan was developed the City of Auburn was in the process of updating the Comprehensive Plan, resulting in updates and changes to the existing plan's policies'. This Downtown Plan has every intent to follow the city's existing policies and procedures, but is also examining existing policies and procedures for potential needed revisions. Any proposed changes will follow all city code, ordinance, and processes needed if revisions are proposed and are not expected to have a significant adverse impact on the environment.

DOWNTOWN URBAN CENTER DESIGN STANDARDS

See Urban Form section.

2.1 Current Conditions

Current Land Use and Ownership

FIGURE 2-1 Land Uses

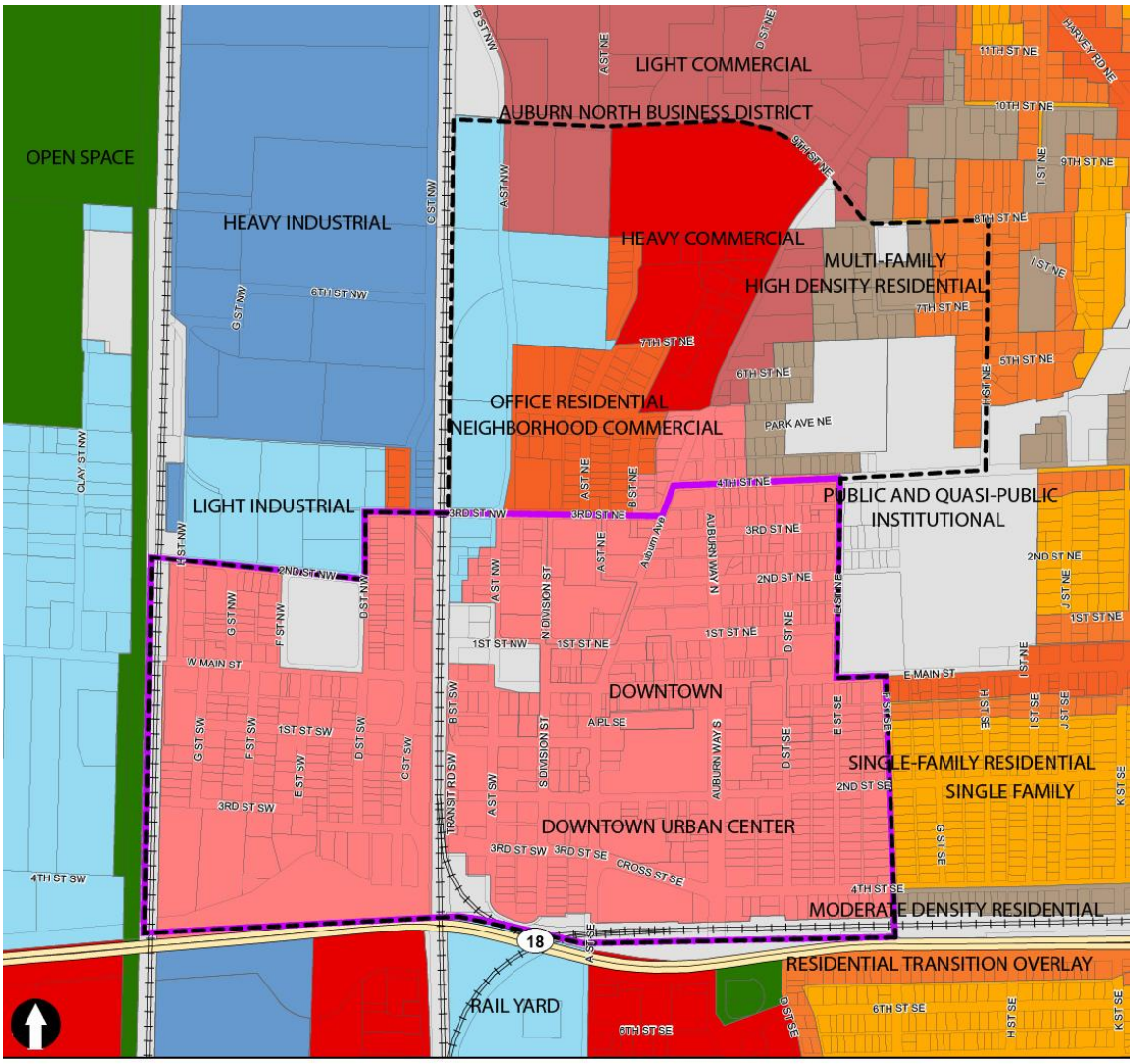


FIGURE 2-2 shows the current uses in the study area, as reported by the King County Assessor. Single-family residential development is clustered in the eastern and western areas, with a larger degree of multifamily development in the northern area. Retail and commercial uses are centered along Auburn Way and Main Street, with a cluster of medical uses in the central area. There are also numerous parking lots in the central core, as well as some industrial uses along the railroad tracks and in the far southwest of the study area.

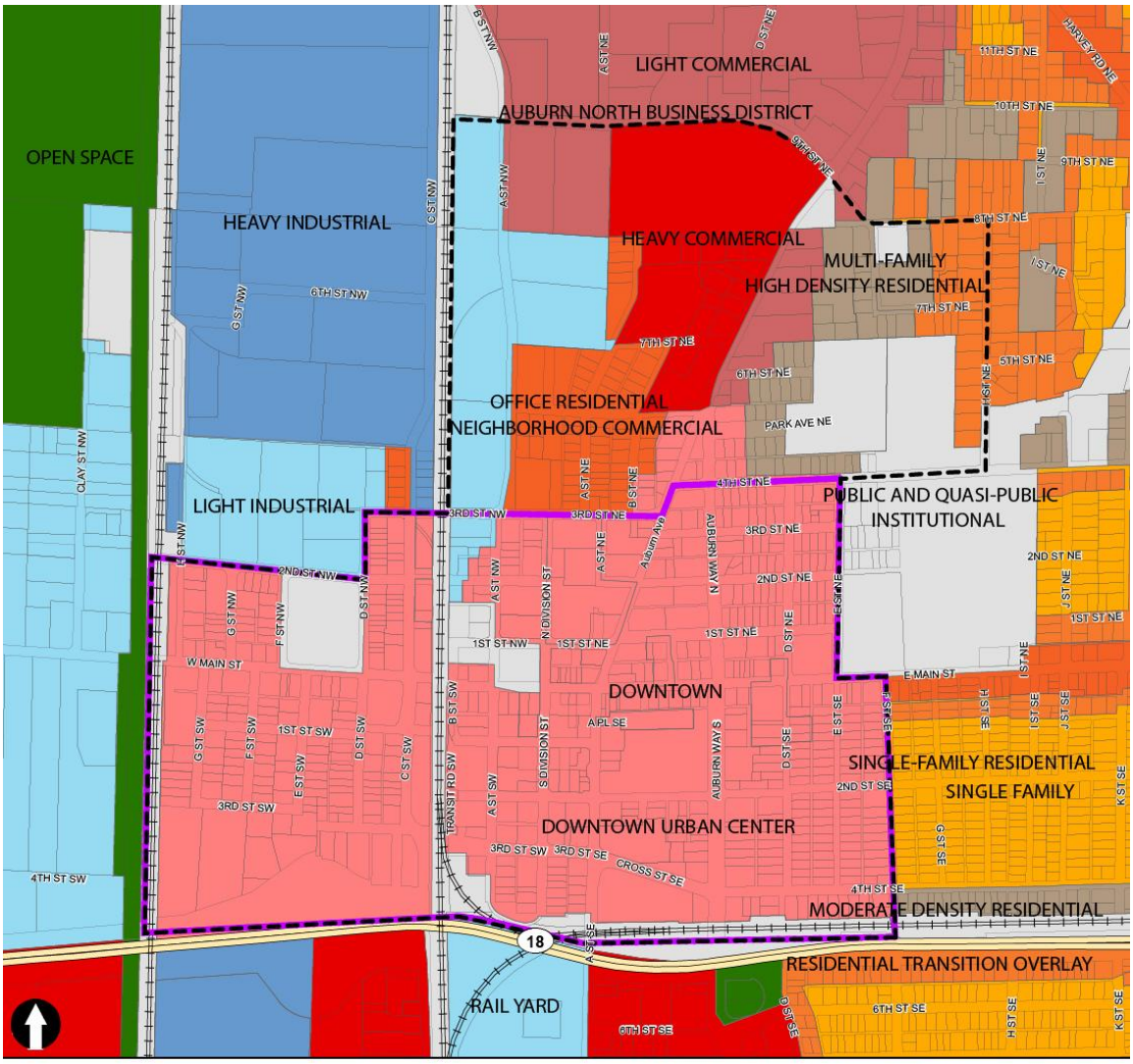
City-owned parcels within the study are shown in Figure 2-3. In addition to the Veterans' Memorial Park and several small parking lots, there are three main clusters of city-owned parcels:

- **City Hall** and the adjacent plaza in front of Legacy Plaza Senior Living

- The former **Auburn Avenue Theater** and adjacent apartment building, which were closed following a 2021 fire and purchased by the city. The Auburn Arts and Culture Center, currently being renovated on the site of a former post office, is located directly to the north of the former theater.
- The **Justice Center** complex, including the police station, justice center, and King County district court.

Currently underutilized and city-owned parcels may be potential sites for redevelopment, particularly the sites which were purchased by the city in the Downtown Core following the 2021 fire. Redevelopment opportunities will be discussed in section 6.3, "Development Areas."

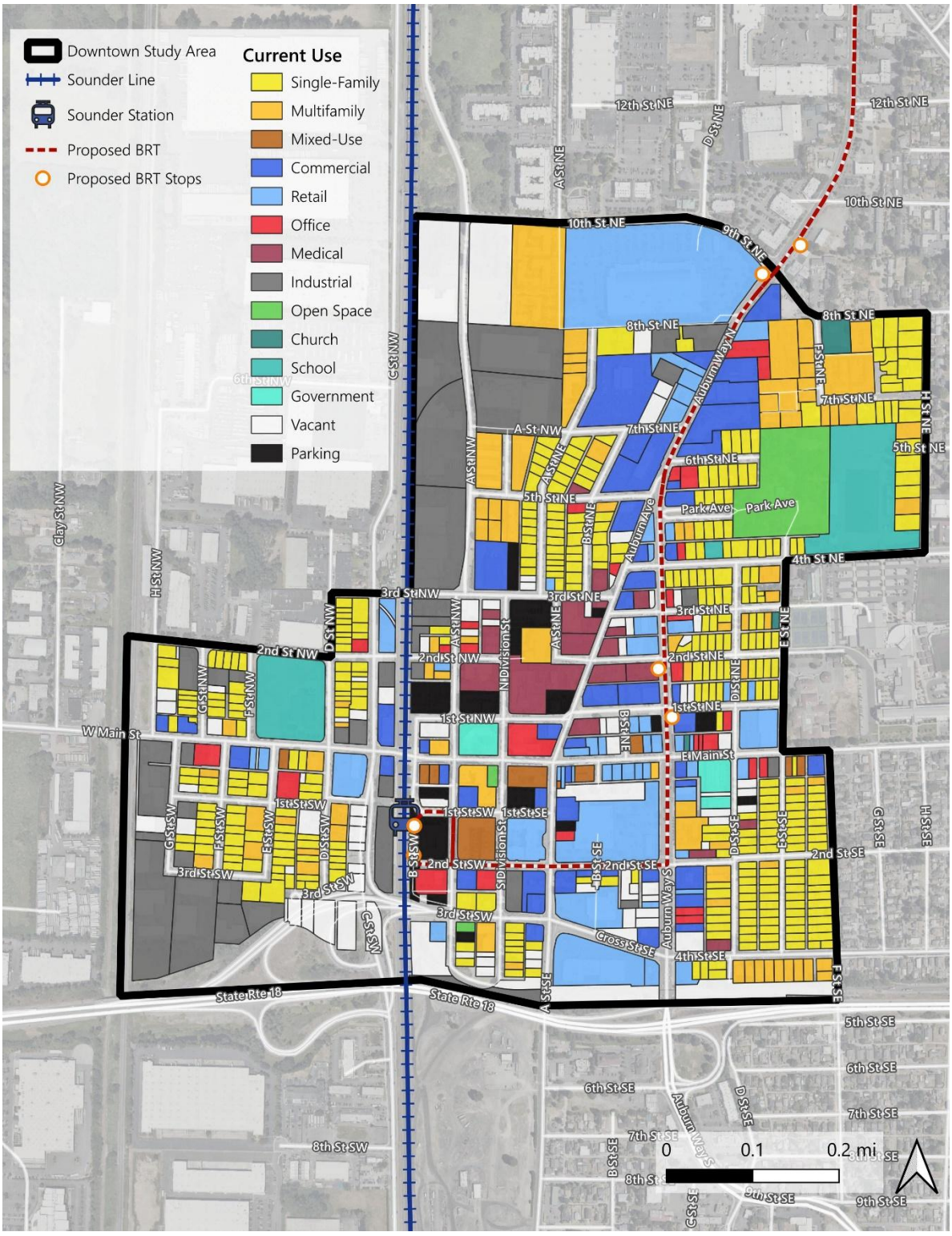
FIGURE 2-1 Land Uses



Land Use

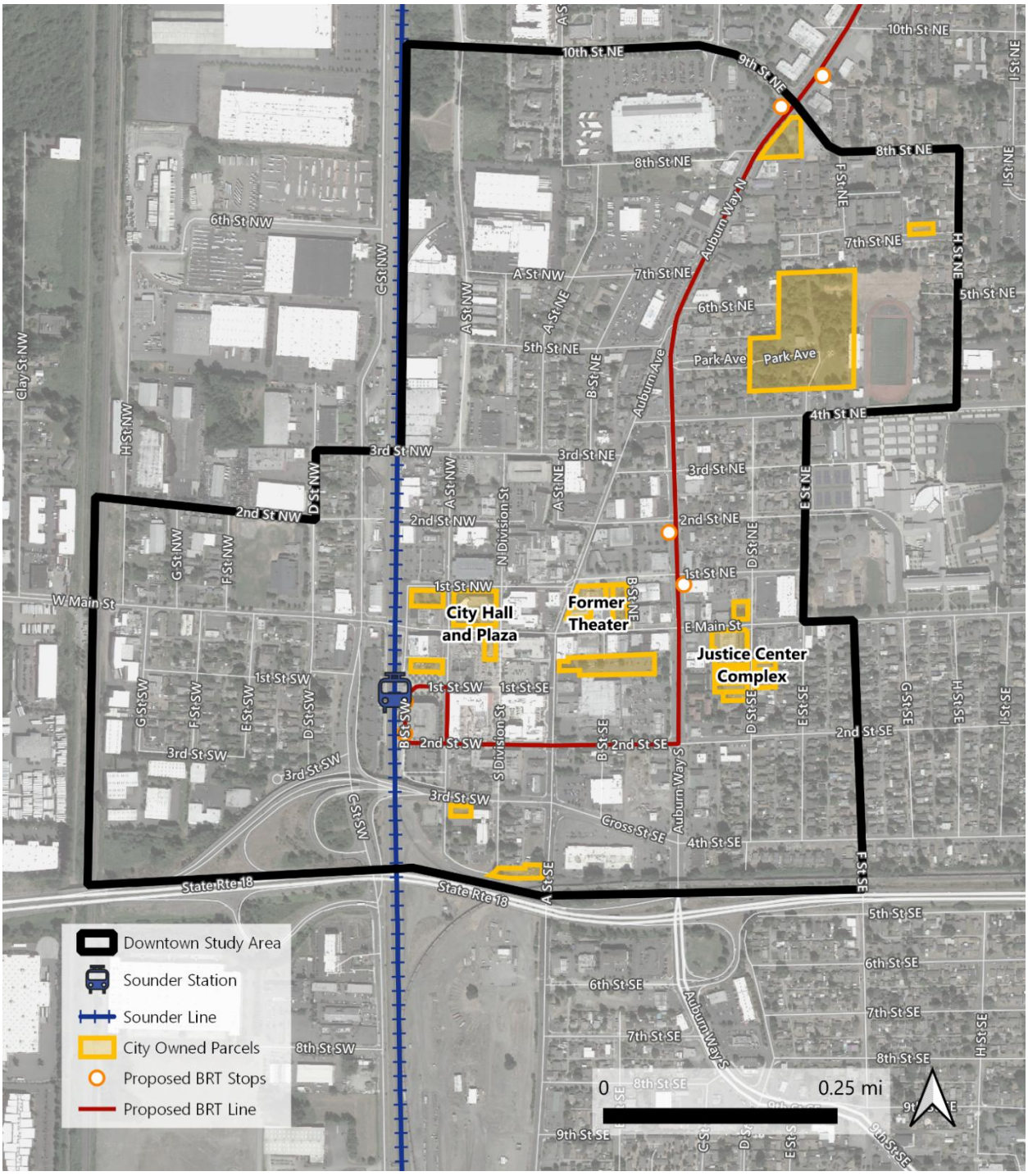
- ACADEMY
- AUBURN NORTH BUSINESS DISTRICT
- DOWNTOWN
- DOWNTOWN URBAN CENTER
- HEAVY COMMERCIAL
- HEAVY INDUSTRIAL
- HIGH DENSITY RESIDENTIAL
- INSTITUTIONAL
- LIGHT COMMERCIAL
- LIGHT INDUSTRIAL
- MODERATE DENSITY RESIDENTIAL
- MULTI-FAMILY
- NEIGHBORHOOD COMMERCIAL
- NEIGHBORHOOD COMMERCIAL OVERLAY
- NORTHEAST AUBURN
- OFFICE RESIDENTIAL
- OPEN SPACE
- PAA PIERCE COUNTY
- PUBLIC AND QUASI-PUBLIC
- RAIL YARD
- RESIDENTIAL TRANSITION
- RESIDENTIAL TRANSITION OVERLAY
- SINGLE FAMILY
- SINGLE-FAMILY RESIDENTIAL
- Study Area
- Current Downtown / RGC
- Railroad
- Auburn limits

FIGURE 2-2 Current Uses in Auburn Downtown Study Area



Source: King County Assessor, Leland Consulting Group

FIGURE 2-3 City-Owned Land in Downtown Study Area

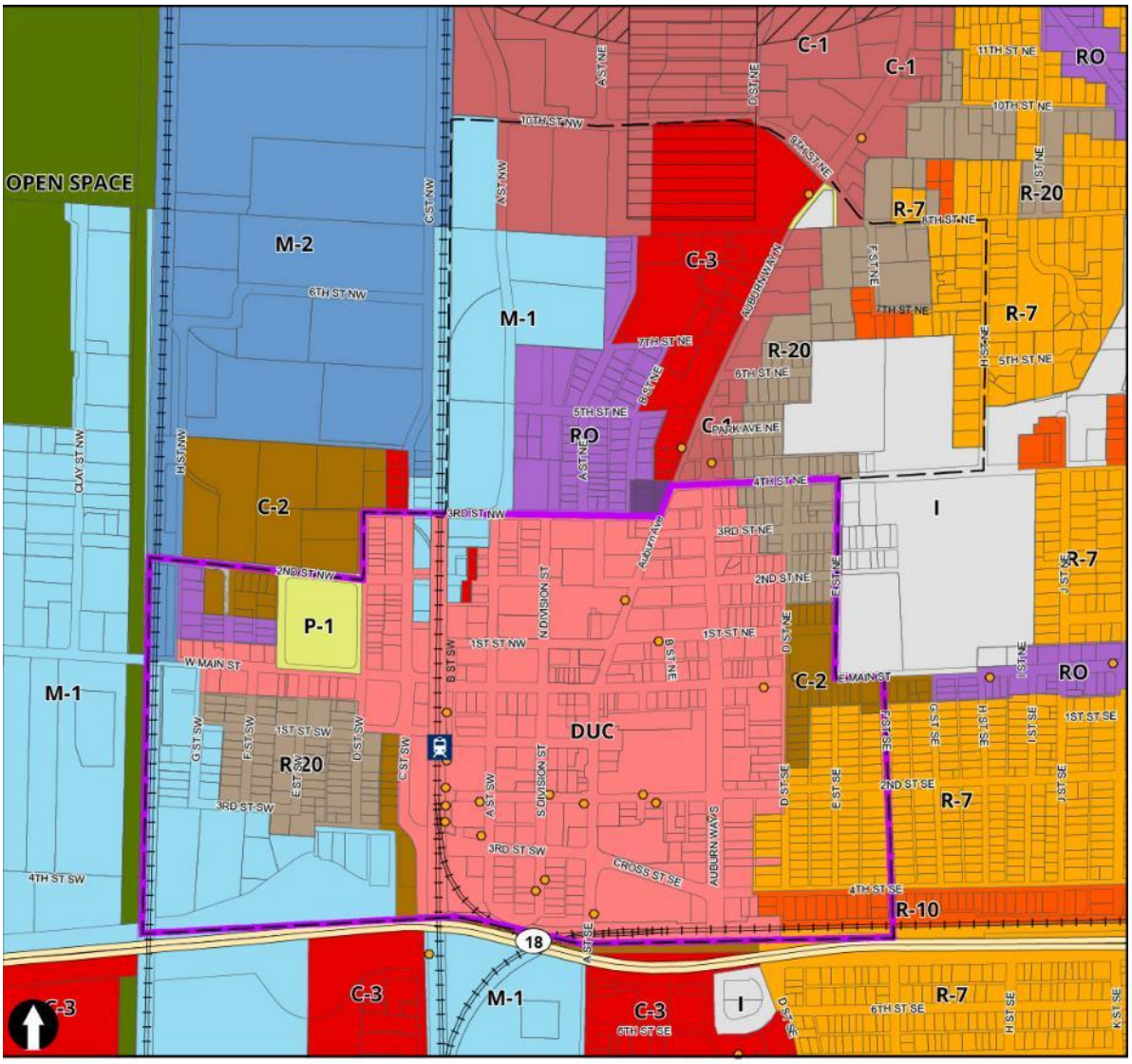


Source: King County GIS, Leland Consulting Group

Current Zoning

The study area includes a diverse mix of existing zones including light industrial, auto-oriented commercial areas, the mixed-use, pedestrian-oriented DUC zone, and residential areas that are predominatnly single-family houses. **FIGURE 2-4** Map of Existing ZoningFigure 2-4 below illustrates the distrbution of the zones across the subarea while Table 1-1 provides an overview of zones wihtin the study area.

FIGURE 2-4 Map of Existing Zoning



SOURCES: City of Auburn GIS data, MAKERS

TABLE 2-1 Existing Zones within the Study Area

Zone	Description/Intent	Size (acres)
Commercial Zones		
Downtown Urban Center - DUC	Create a distinct and strong identity for downtown Auburn that produces a concentration and mixture of commercial, office, medical, retail, residential and civic uses within the downtown area; encourages private and public investment, attract shoppers and visitors, and appeal to existing and new residents; and provides a development pattern that supports pedestrian movement, bicycles and use of public transit.	133.13
Light Commercial District - C1	Intended for lower intensity commercial adjacent to residential neighborhoods. This zone encourages leisure shopping and provides amenities conducive to attracting shoppers and pedestrians.	23.4
Central Business District - C2	Set apart the portion of the city proximate to the center for financial, commercial, governmental, professional, and cultural activities. Uses in the C-2 zone have common or similar performance standards in that they represent types of enterprises involving the rendering of services, both professional or to the person, or on-premises retail activities. This zone encourages and provides amenities conducive to attracting pedestrians.	11.9
Heavy Commercial District - C3	Allow for medium to high intensity uses consisting of a wide range of retail, commercial, entertainment, office, services, and professional uses. This zone is intended to accommodate uses which are oriented to automobiles either as a mode or target of the commercial service while fostering a pedestrian orientation.	29.09
Residential Zones		
Residential R7	Create a living environment of optimum standards for single-family dwellings. It is further intended to achieve development densities of five to seven dwelling units per net acre. This zone will provide for the development of single-family detached dwellings and for such accessory uses as are related, incidental and not detrimental to the residential environment.	24.46
Residential R10	Permit some increase in population density in those areas to which this classification applies by permitting single-family dwellings and duplexes … maintaining a desirable family living environment by establishing minimum lot areas, yards and open spaces. A related consideration is to provide a transition between single-family areas and other intensive designations or activities which reduce the suitability for single-family uses.	5.61
Residential R20	Provide for multiple-family residential development and is further intended as a residential zone primarily of multiple-family residences, except as specifically provided elsewhere in this chapter.	39.04
Residential Office District – RO	Accommodate small-scale business and professional offices, medical and dental clinics, and banks and similar financial institutions at locations where they are compatible with residential uses. Some retail and personal services may be permitted if supplemental to the other uses allowed in the zone. This zone is intended for those areas that are in transition from residential to commercial uses along arterials or near the hospital.	23.41
Residential Office District (Hospital) -RO-H	The RO-H designation is to be used exclusively for the hospital area, located in the vicinity of 2nd Street NE and Auburn Avenue, and is intended to be used for medical and related uses and those uses compatible with the medical community.	1.04

Industrial Zones		
Light Industrial District – M1	Accommodate a variety of industrial, commercial, and limited residential uses in an industrial park environment, … and to provide a greater flexibility within the zoning regulations for those uses which are non-nuisance in terms of air and water pollution, noise, vibration, glare or odor. The light industrial/commercial character of this zone is intended to address the way in which industrial and commercial uses are carried out rather than the actual types of products made.	58.79
Heavy Industrial District – M2	Accommodate a broad range of manufacturing and industrial uses. Permitted activity may vary from medium to higher intensity uses that involve the manufacture, fabrication, assembly, or processing of raw and/or finished materials. Heavy industrial uses should not be located near residential development.	2.29

SOURCES: Auburn City Code, Title 18 Zoning, MAKERS

2.2 Regional Growth Center Considerations

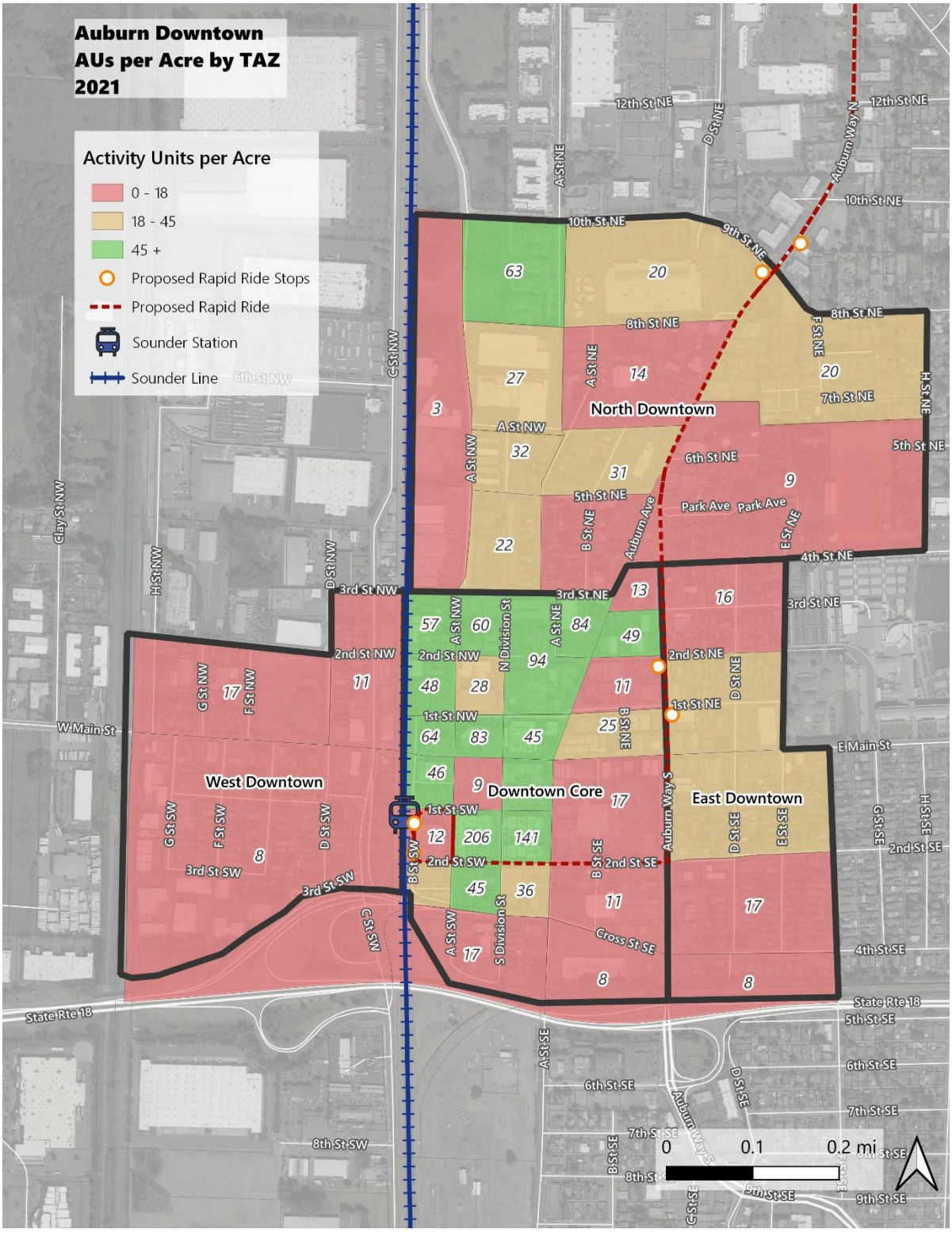
The Puget Sound Regional Council (PSRC) uses "Activity Units" to measure density of development and potential for growth within the Regional Growth Center framework. An "activity unit" is one person or one job. As discussed above, the current Auburn Downtown Urban Center Regional Growth Center (RGC) is comprised of the Core, East, and West Downtown subareas of the study area. RGCs and other types of centers are eligible as "priority areas for PSRC's federal transportation funding" and "support VISION 2050's objective of encouraging development of compact, livable centers as an opportunity to accommodate a significant portion of the region's growth." PSRC's requirements require a number of criteria for Urban Growth Centers:

- Minimum **18 activity units per acre** existing density
- Minimum **45 activity units per acre** planned density
- Size between **200 and 640 acres**
- Minimum mix of **15%** residential and employment activity[2]

Figure 2-5 shows the current RGC Boundary along with the activity unit density by Traffic Analysis Zone (TAZ). Auburn's TAZs have recently been updated as part of its current comprehensive planning process. The number shown below on the map is the total Activity Units (AUs) (people and jobs) per acre within each TAZ. Red TAZs represent an AU density **below** the current minimum RGC threshold of 18. Yellow TAZs show an AU density **between** the current minimum of 18 and the planned minimum of 45, and green TAZs are already **in excess** of the planned minimum of 45 AUs per acre

[2] Puget Sound Regional Council. "Regional Centers Framework Update." March 22, 2018. https://www.psrc.org/media/3038

FIGURE 2-5 Current Activity Units per Acre by TAZ with RGC Boundaries, 2021



Source: PSRC, City of Auburn, Fehr & Peers, Sound Transit, King County, Leland Consulting Group

The current and projected units, population, jobs, and AUs are shown below in Table 2-2 and Table 2-3. These projections were created using a number of assumptions:

- Population in the downtown area has increased rapidly in the past decade. It is forecast to continue to increase, but at a slower rate. This scenario assumes the next 20 years will see a **yearly population growth of 2.4 percent** – 25 percent less than the rate seen over the past decade.
- Most of the single-family neighborhoods in the study area are relatively built-out and most new residential development can be expected to occur in multifamily projects such as those recently seen in the downtown core. However, some middle housing (i.e., townhome development and ADUs) may take place. We estimate this would account for about 5 percent of new housing in the area, with **95 percent of housing in multifamily units**.
- The current household size in the study area is 2.12 people per household. These projections assume this will **remain consistent**, as it is already within the common range for downtown areas and Transit-Oriented Developments (TOD).
- This forecast assumes that jobs in the study area will increase at a rate of **0.6 percent per year**, an average between the rates seen over the past 10 and 20 years.

TABLE 2-2 2021 Activity Units in Downtown Study Area

Downtown Area	Housing Units	Population	Jobs	Activity Units	Acres	AUs/Acre
West	138	349	491	840	72	11.7
Core	664	1341	2618	3,959	90	44.0
East	231	563	445	1,008	55	18.2
North	691	1455	1245	2,700	144	18.8
Total	**1,724**	**3,708**	**4,799**	**8,507**	**361**	**23.6**
Current RGC Boundary	1,033	5,807	3,554	5,807	217	26.7

Source: Leland Consulting Group

TABLE 2-3 2044 Activity Units in Downtown Study Area (Projected)

Downtown Area	Housing Units	Population	Jobs	Activity Units	Acres	AUs/Acre
West	410	900	575	1,475	72	20.5
Core	2459	4931	3617	8,548	90	95.0

East	357	815	557	1,372	55	24.8
North	1031	2135	1553	3,688	144	25.7
Total	**4,257**	**8,781**	**6,302**	**15,083**	**361**	**41.8**
Net New	*2,533*	*5,073*	*1,503*	*6,576*		*18*
Current RGC Boundary	3,226	6,646	4,749	11,395	233	48.9

Source: Leland Consulting Group

This analysis suggests that the downtown study area would capture approximately 18 percent of new housing unit target (12,000 units) and 7 percent of its new jobs target (19,520 jobs) set forth in the PSRC VISION 2050 framework.

As shown above, the current AU density in the study area is 23.6, with a projected increase to 41.8 by 2044. The current RGC shows 26.7 AUs per acre with a projected increase to 48.9 by 2044.

2.3 Preliminary Land Capacity Analysis

Table 2-4 shows a preliminary analysis of the required land for the projected development needed to accommodate the population and job increases discussed above. The analysis uses the King County assessment of vacant and redevelopable parcels within the study area and their current zoning and finds that **if all vacant or redevelopable parcels were used, there would be a surplus of 34.4 acres of land beyond what would be required to accommodate the projected 2044 increases in population and jobs within the study area**. This analysis uses several assumptions as follows:

- As above, **95 percent** of new housing units are expected to be multifamily units, with the rest comprised of infill and middle housing development such as townhomes and ADUs.
- Allowed single-family density is assumed to be **13.5 units per acre**, an average of the allowed densities of single-family zones in the study area.
- Multifamily density is assumed to be **100 units per acre**. The average density of the five most recent developments in Auburn's downtown is 167 units per acre. Given that these are particularly dense developments, a more conservative estimate was used assuming there may be some smaller podium developments or lower density apartment development, potentially in the northern area.
- A figure of **400 square feet per job** was used, based on the assumptions in the 2021 King County Urban Growth Capacity Report

TABLE 2-4 Required and Available Land in Auburn Downtown Study Area, 2022

Acres Required	Vacant/Redevelopable	TOTALS

Downtown Area	Single-Family	Multifamily	Employment	Residential	Commercial/ Mixed	Total Available	Total Required	Surplus/ Shortage
West	0.3	1.7	1.6	5.5	2.2	7.7	3.6	4.0
Core	1.6	8.8	2.9	0.0	17.1	17.1	13.3	3.8
East	0.5	2.7	0.8	0.6	1.9	2.5	4.0	-1.5
North	1.6	9.1	2.6	4.3	24.7	29.0	13.3	15.8
Total	**3.9**	**10.1**	**7.9**	**10.4**	**45.9**	**56.3**	**21.9**	**34.4**

Source: City of Auburn, King County, Leland Consulting Group

2.4 Key Findings and Implications for Plan

POPULATION AND EMPLOYMENT FORECASTS

- By 2044, the downtown area can be expected to add 4,534 new residents in 2,196 new housing units and 1,356 new jobs, based on recent development and employment trends. Based on King County's assessment of vacant and redevelopable land, the downtown area has sufficient land capacity for this level of development.

ZONING CONSIDERATIONS

- The DUC zone already applies to much of the DUC area. Lower-density zone areas are primarily in West Downtown, East Downtown, and North Downtown areas.
- Zoning changes that increase density on current C1 areas could offer transit-oriented development opportunities.
- There is a small amount of Heavy Industrial zoning in the West Downtown Area, which may not be fully compatible with overall vision for the subarea.
- The Central Business District Zone, which covers East Main St has no setbacks and a different height limit from surroundings but still high parking requirement.

STRENGTHS AND OPPORTUNITIES

- Staff and stakeholders voiced a belief that the revitalization of downtown Auburn is underway, but that the revitalization process is not complete–there is more to come.
- Sounder and upcoming King County RapidRide services are assets to future development within downtown.
- The city-owned Auburn Avenue Theater and former Max Apartments site presents a significant opportunity and challenge for the city, as the vision appears to be to recreate a theater along with ancillary development.
- Other city-owned properties, such as surface parking lots, could offer additional sites for new development, or could continue to serve as surface parking. These property assets will enable the City to play a significant role in guiding Downtown's development in the

coming decades, through renovations, modifications, and/or major redevelopment projects.

- There are a number of large and mid-size commercial properties in downtown. Most have large surface parking areas that reflect parking ratios desired by commercial tenants in the mid- to late-20th century.
    - In the short and medium term, businesses on these sites may continue to operate as they have in the past. However, looking over a 20+ year time horizon, these sites appear to offer redevelopment opportunities that can accommodate more mixed-use development.
    - Some of the buildings will reach the end of their lifespan and the sites can be redeveloped in a way that reflects their highest and best use—as denser, mixed-use projects. Some existing tenants can be brought back into new mixed-use projects as ground floor tenants.

SECTION 3 URBAN FORM

This section covers the current form and condition of the built environment within the study area.

3.0 Existing Policies and Regulations

Local Policy Framework

DOWNTOWN URBAN CENTER DESIGN STANDARDS

The DUC Design Standards provide design direction and guidance for buildings, sites and landscape areas, streets and streetscapes, and signage to encourage a cohesive, pedestrian-oriented urban fabric. The guidelines were first adopted in 2007 and have been amended several times since.

MAIN STREET VISION PLAN

Vision plan for streetscape and pedestrian improvements for East Main Street. Thorough analysis highlights street grid and block length challnges, as well as pedestrian and bike access needs.

Current Conditions Overall Urban Form

Urban form within the subarea shows significant diversity within a small geographic area. Industrial areas along the two railway corridors reflect the industrial and agricultural heritage of the City of Auburn. Early and mid-20th century buildings within the Downtown Core and along W/E Main St ground more recent, dense urban development at the heart of the DUC. Public plazas, walkable streets, and permeable ground-floors further contribute to the pedestrian-oriented city-center area.

Auto-oriented commercial areas, particularly along arterials, support a range of commercial uses, but also create circulation challenges for people walking, biking, and accessing transit through the area. The office and medical hub around MultiCare feels distinct from the surrounding areas, and could offer more development opportunities.

Residential areas include single-family neighborhoods east of Auburn Way S and some multi-family complexes east of Auburn Ave. Veterans Memorial Park is key amenity for the area north of Downtown, providing green space and recreational opportunities.

The existing pedestrian environment ranges significantly throughout the study area, reflecting both the breadth of existing uses, recent investments and redevelopment, and aging infrastructure and

areas where updates are needed. Elements that contribute to safe and comfortable pedestrian environments include sidewalk widths adequate to support adjacent uses, street trees for shade and planting areas to provide buffer from vehicle traffic, buildings that relate to and engage streetscape, pedestrian lighting, seating opportunities, and public art.

Feedback from early stakeholder and community engagement identified several key themes and needs:

- Want more things to do downtown – place to eat, shop, etc. The theater that burned was mentioned as significant loss multiple times in both community event and at stakeholder meetings.
- Want downtown to be a central gathering place for all – needs to feed welcoming and safe, have good lighting at night to enhance security, etc.
- Need for more open space and green space
- Multimodal investments are important - Streetscape improvements are important for economic development
- Need for more diverse housing options – having more residents downtown will help with overall revitalization.
- Finding affordable commercial spaces are a key current challenge for existing local businesses.

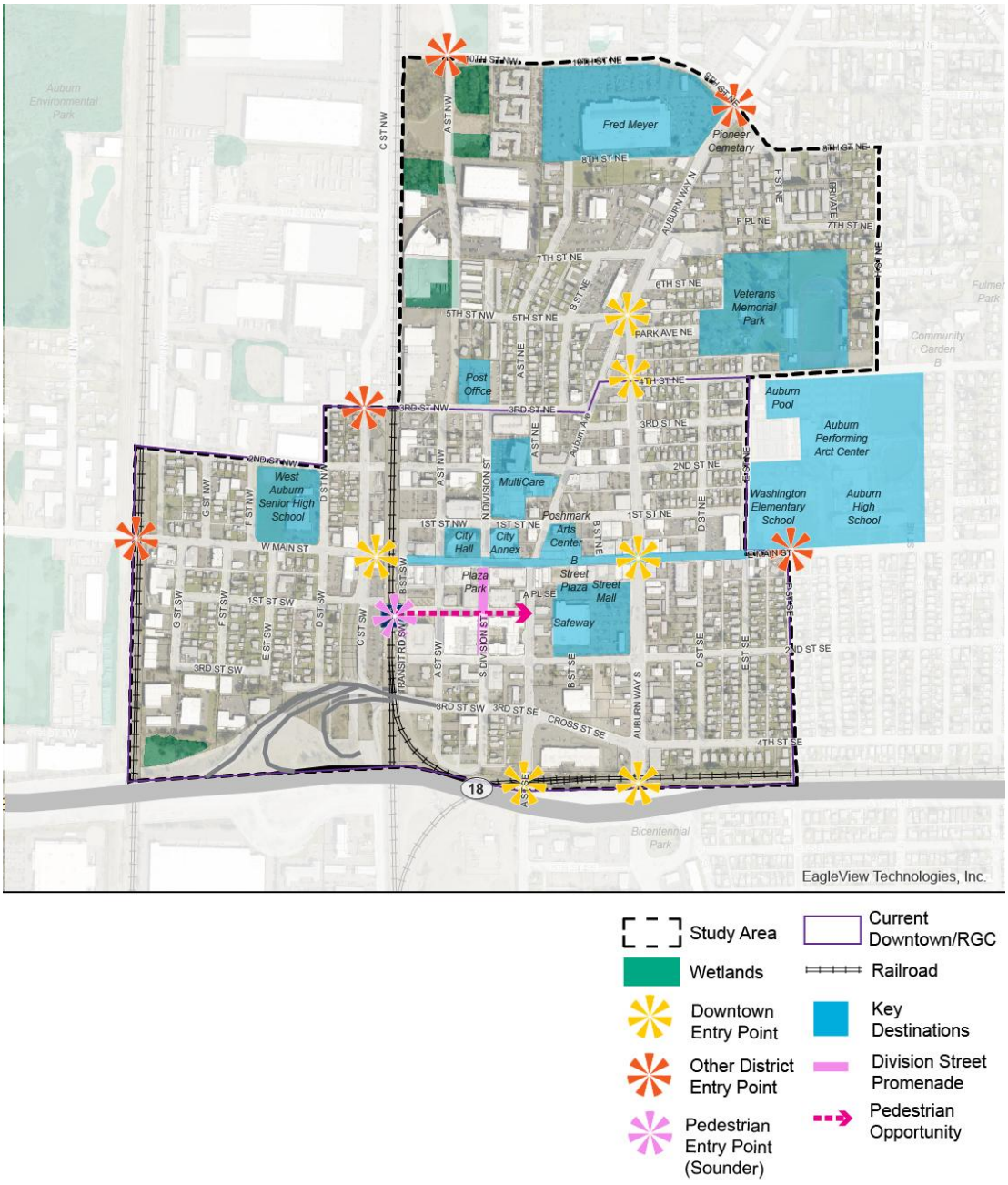
GATEWAYS AND DESTINATIONS

There are several natural gateways into the study area, as well as into the Core Downtown area. While most are currently auto-oriented, some could offer multimodal opportunities in the future. The Sounder Station offers an important pedestrian gateway into downtown.

Key destinations include:

- MultiCare
- Sounder Station
- City Hall
- Safeway
- Fred Meyer
- W/E Main Street Businesses
- Former Theater (planned future Arts/Community Hub)

FIGURE 3-1 **Gateways and Destinations**



SOURCES: MAKERS

PHYSICAL BARRIERS

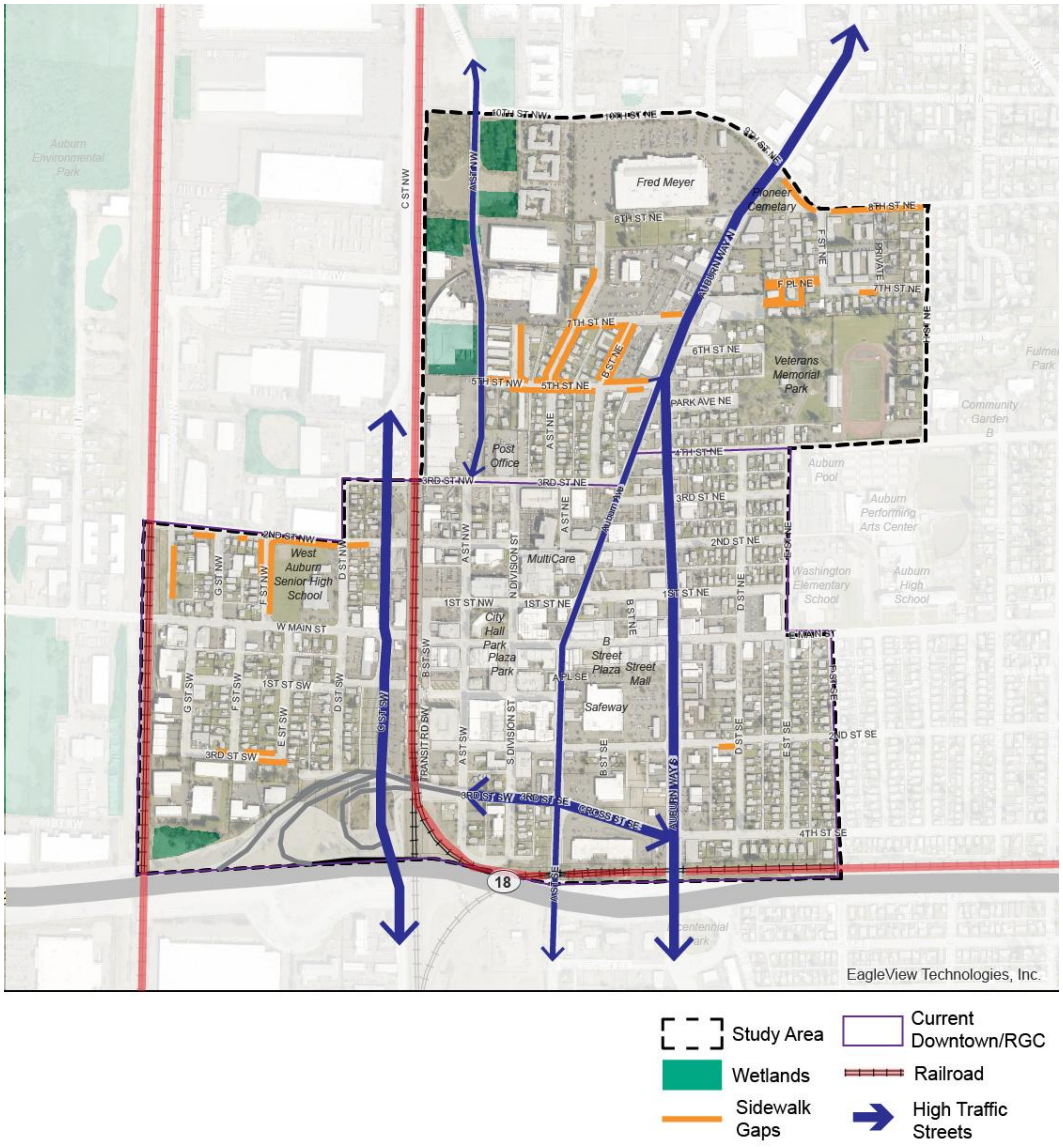
Recent mixed-use development and street improvements within the Downtown Core have improved the pedestrian environment, however arterial streets and auto-oriented commercial areas continue to present challenges to comfortable circulation for people walking, biking and using transit. The BNSF/Sounder railway corridor, coupled with the scale and traffic along the C St arterial do not promote a welcoming pedestrian environment between West Downtown and the Downtown Core. Pedestrian underpass connections below SR18 are not inviting for pedestrians and the area lacks a sense of welcome into the Downtown Core for traveling from South Auburn neighborhoods. A safety analysis found that some Principal Arterial and Arterial streets, which carry higher numbers of vehicles, have higher numbers of collisions. (See Safetyon page 7-16.)

The plan will review the arterials to determine what types of improvements (eg. streetscape improvements with redevelopment as well as crossing safety improvements at intersections) will be needed to enhance multimodal circulation and make the overall area more walkable.

Arterials to investigate include:

- Auburn Ave
- Auburn Way S
- C St NW
- 10TH St NE
- Cross Str SE

FIGURE 3-2 **Physical and Circulation Barriers**

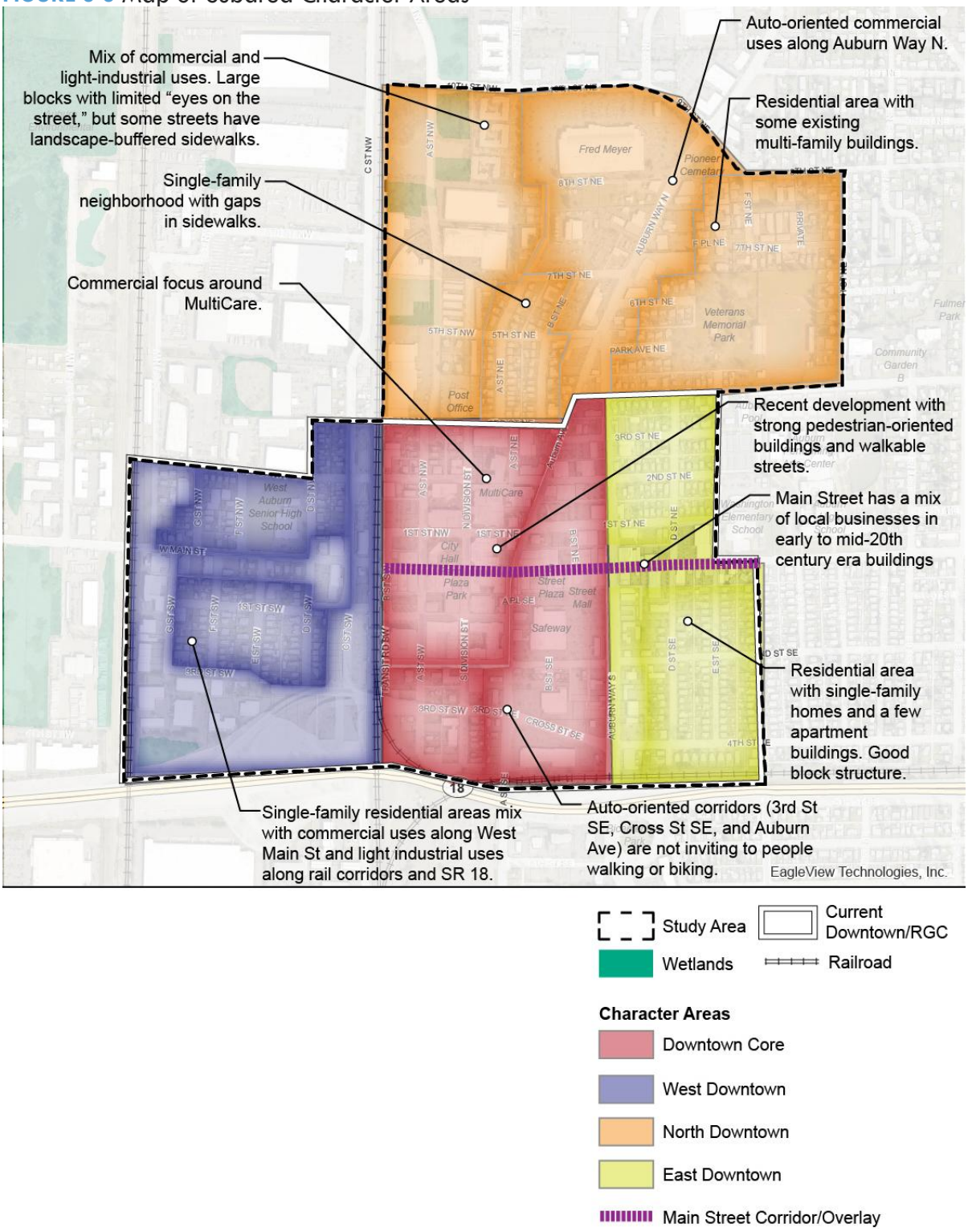


SOURCES: MAKERS

Downtown Districts

To better understand current conditions within the subarea and analyze future opportunities, the team divided the subarea into four districts and assessed current conditions within each: Core Downtown, West Downtown, North Downtown, and East Downtown.

FIGURE 3-3 Map of Subarea Character Areas



Source: MAKERS

DOWNTOWN CORE

The Core Downtown area was the primary focus of the 2001 Downtown Plan and has seen significant public and private investment over the last two decades. These investments have resulted in a strong pedestrian environment, with streetscapes that are accessible, support adjacent use need, and invite people to walk. The curbless design along a portion of S Division St is a key investment that supports a pedestrian-oriented core downtown area, and could be utilized for festivals or other public events. Public plazas within the Core Downtown area further support the pedestrian environment.

The Core Downtown area also retains some two and three-story older buildings, which reflects the historic built form of Downtown Auburn. These buildings are primarily located along the Main Street corridor, but are also present in other areas within the Downtown Core.

A mix of new and historic pedestrian-oriented building types and successful implementation of pedestrian-friendly street design has created a walkable urban form in many parts of the Downtown Core. With a walkable built form in place a remaining challenge is to increase activity by focusing on existing under-utilized commercial spaces, as well as programming of open spaces and streets. Even in relatively pedestrian-friendly areas, opportunities remain to reallocate street space and parking areas for uses that better support a more vibrant public realm and business environment, and to improve the comfort and interest of the public realm through street trees, water features, and art.

Recent Redevelopment

Redevelopment in this area has been concentrated in the blocks west of B Street NW, east of A Street SE, south of W Main Street, and north of 2nd Street SE, though some new developments are located outside of this area. Several sites with large parcels, older buildings, and/or car-oriented commercial uses with large parking lots in the Core Downtown could provide future infill development opportunities.

MultiCare Hub

MultiCare, located west of Auburn Ave, between 1st Street NE and 3rd Street NE, is a major employer and destination that anchors the northern end of the Core Downtown area. MultiCare plans to expand within existing parking areas of the site. Sound Transit also has plans to build a new parking garage structure in this area.

Auto-oriented Commercial

Some auto-oriented commercial uses remain in the downtown core, such as along the corridors of S 3rd St SE, Cross St SE, and Auburn Way S. The Safeway grocery store, an important community asset for downtown, has a large surface parking lot that could present future infill development opportunities. The east-west alignment of the Safeway site and the Sounder station and pedestrian plaza could offer a strong multimodal connection within downtown.

Industrial

There are also a few industrial commercial uses in the Core Downtown area west of A Street NW and north of 1st St NW, along the BNSF/Sounder railroad corridor. These include warehouses, surface parking lots, and some outdoor storage to support commercial activities.

FIGURE 3-4 Images of the Downtown Core



Source: MAKERS

MAIN STREET CORRIDOR

Once one of the principal shopping destination in the valley, Main Street retains a mid-20th century style, with single-story commercial buildings and small businesses lining the street. The commercial area engages pedestrians with small-scale storefronts, multiple windows and clear sidewalks, pedestrian lighting, and public art. The commercial street is home to a diverse mix of small and local businesses, many of which have multilingual signage and likely serve Auburn and South King County residents from diverse cultures and ethnic backgrounds. It crosses both the Core Downtown and the East Downtown character areas.

There are a few 2-3 story early 20th century buildings along W Main Street (west of N Division St) that connect to the history of downtown and include groundfloor uses that activate the corridor. Many of the buildings along E Main Street (east of N Division St) retain the mid-century architectural style of a commercial street, with small department stores and shops mixing with office and civic buildings. The aging buildings in this area also reflect a range of condition – some have been updated while others may require increased maintenance or renovation to continue to support existing or new commercial uses.

Sidewalk improvements along portions of E Main St also contribute to an inviting and comfortable pedestrian environment. Street parking buffers pedestrians from vehicle traffic in these areas, but as pedestrian volumes increase, these parking spaces could become opportunities to expand pedestrian space.

There is an emerging opportunity for the City to make new investments at the properties where the Auburn Arts and Culture Center and the Auburn Ave Theater are located. The Auburn Ave Theater was impacted by a fire at an adjacent building, but the City is exploring new opportunities for these sites, which could provide an arts and cultural hub between the Core Downtown are and East Downtown and Main Street.

FIGURE 3-5 Images of Main St Corridor



Source: MAKERS







Source: MAKERS

WEST DOWNTOWN

The West Downtown area is located west of the BNSF/Sounder railroad corridor and C ST NW arterial and east of the Union Pacific railroad corridor. The intersection of E Main St and B St NW is one of the key vehicle gateways into the Core Downtown area, but access is challenging for pedestrians and bikes in this location. The intersection is also a major barrier for people with limited mobility. The Sound Transit Sounder station overpass that is located to the south only crosses the railroad corridor, so people with limited mobility have to travel out of their way, and then still must cross a major arterial to get to West Downtown. (See Transportation for more information on multimodal access in the study area.)

West Main Commercial Uses

W Main St features a mix of commercial uses, some located in formerly residential buildings, including several small, locally-owned businesses. The west Main St corridor has sidewalks and

some public art, but intermittent parking areas and differing setback patterns along the corridor fail to provide strong definition to the space.

Residential/Industrial Mix

North and south of Main St, West Downtown has a small grid of streets, with inconsistently sized block featuring an eclectic mix of residential, commercial, and light industrial uses. West Auburn Senior High School, a technical high school alternative for Auburn students, anchors the area. A mostly residential neighborhood surrounds the school, comprised primarily of older single family houses.

The street grid in the area is somewhat irregular, with smaller blocks and parcels along W Main St, and larger blocks (a few with alleys) and larger parcels to the north and south. Industrial uses are most common at the extreme north and south of the area, with larger, more recently constructed warehouses and flexible business parks.

FIGURE 3-6 Images of West Downtown







Source: MAKERS

NORTH DOWNTOWN

Unlike other parts of downtown, the area north of 3rd Street NE was developed after WWII and has historically been somewhat separate from Downtown Auburn. It has a more-auto-oriented built form and less-complete street grid, but could present opportunities for future redevelopment and infill residential. This area has the most diverse mix of uses and existing building styles within the study area.

Commercial Corridors

Auburn Ave is a key arterial corridor through this area, creating some divisions and distinctions between uses. Commercial uses predominate along both the Auburn Ave and the Auburn Way N corridors, which are flanked by residential areas on both sides. Fred Meyer is the existing commercial anchor at the northern edge.

Industrial Uses and Business Parks

On the western edge industrial uses, similar to those in the Core Downtown area, extend from the BNSF railroad corridor east to A Street NW (and to A Street NE in some areas.)

Residential Pockets

Pockets of single family residential located between 3rd Street NW/NE and 7th Street NE that have a smaller street grid than the Core Downtown or and industrial portions of the study area. The presence of alleys in residential street grid areas both east and west of Auburn Ave provide good site access, creating the opportunity for infill housing.

East of the Auburn Way corridor is a mixed residential area with single-family and multifamily housing. The area has limited internal street connectivity, with many small private roads and driveways. Veterans Memorial Park is a key open space and cultural asset in this area. The boulevard style of the Park Ave entrance, with the alley of mature existing trees, is unique and adds green infrastructure to the area. This area is also close to Auburn High School and the Auburn Performing Arts center, and key community destination in Auburn.

FIGURE 3-7 Images of North Downtown Area



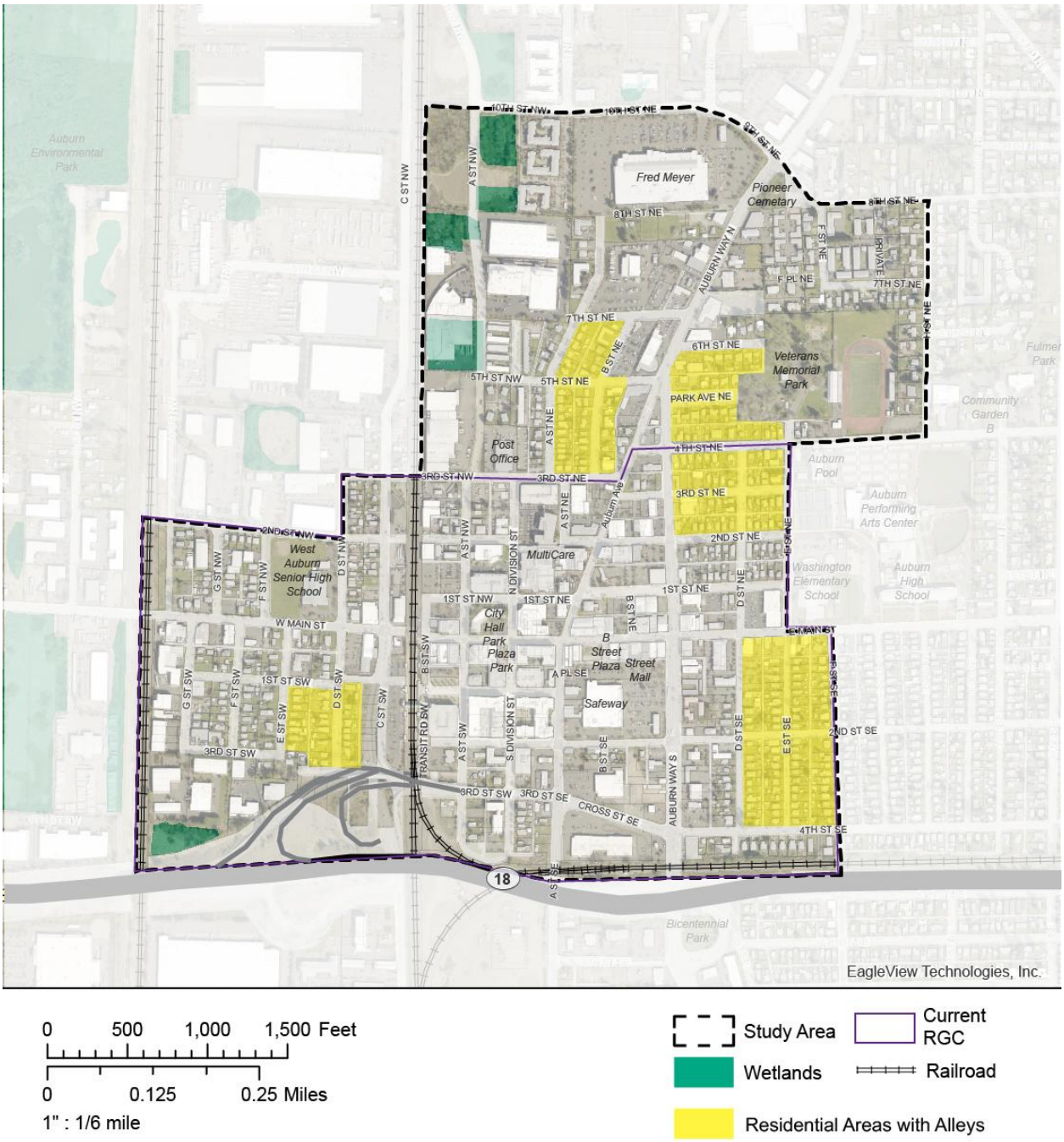
Source: Google Street View





Source: Google Street View and Google Maps

FIGURE 3-8 Residential Areas with Alley Access



SOURCES: MAKERS

EAST DOWNTOWN

Residential Surroundings

North and south of E Main Street is a single-family residential neighborhood with a well-connected street grid of blocks approximately 350 by 600 feet and pre-war houses on small lots. The neighborhood is within close and easy walking distance of E Main Street businesses and the Core Downtown area. There are a few multifamily developments along Auburn Way S as well.

FIGURE 3-9 Example MF and SF typical in the East Downtown Area



Source: Google Street View

Views and Solar Access

- Likely not a big driver for Downtown Plan – not a lot of existing views, streets not oriented to Rainier vistas
- Solar access may be a consideration for new park development

3.1 Key Findings and Implications for Plan

- Study area includes diverse range of existing housing – potential to increase multifamily, but also missing middle housing types.
- There is very little open space and tree canopy cover in the study area (except for some in residential areas and Veterans Memorial Park.) Downtown would benefit from more green open space and access to shade to reduce urban heat.
- Downtown has limited class II and class I[3] bikeways although the downtown area is in proximity to regional trails.

[3] This refers to the definitions for Biking LOS standards that the city is using for the 2024 Comprehensive Plan update. Class II bikeways are generally bicycle lanes in the roadway but separated from vehicular traffic. Class I bikeways are bicycle facilities that are outside the roadway and are usually separated from roadway traffic by curbing, landscaping, buffer hardscaping, or physical barriers.

- Many arterial streets have minimum five-foot-wide sidewalks without planter strips. Some busier streets with higher traffic volumes don't feel welcoming or comfortable for pedestrians.
- Historic buildings in many areas provide link to the past.
- Value of Veterans Park – asset for redevelopment in surrounding area around the park (North Downtown)
- School district facilities may also provide some open space benefit – need to confirm access by community
- Redevelopment of Downtown Core is delivering a strong pedestrian built environment.
- Plan should explore opportunities to increase activation through groundfloor commercial uses, events, creative streetscape uses/programs, and/or linking of public space and streetscape improvements.
- There are several retail spaces in newer developments that have been slower to fill, leaving vacant groundfloor spaces at the street level.
- MultiCare is a major employer, and anchors a small subdistrict within downtown. Expansion plans may bring opportunities to continue to develop this hub.
- Historic Main Street has a special form that cannot be duplicated in new suburban development. Main Street provides a sense of history and authenticity.
- Access through the area is challenged by arterials, sidewalks that don't meet current standards, and gaps in sidewalk infrastructure in some areas.
- Arts and culture is a resonant theme within the community and could help support further revitalization, particularly between along the East Main Street corridor.

SECTION 4 NATURAL ENVIRONMENT

This chapter describes existing natural environment conditions within the City of Auburn Downtown study area based on available city and regional GIS data. This is a high-level assessment of the natural environment within downtown Auburn to inform the development of the downtown Plan. Additional investigation may be needed if any of these elements are included in Planned Action EIS that is associated with this downtown Plan.

4.0 Existing Policies and Regulations

This section identifies City policies and regulations for critical or environmentally sensitive areas.

Critical Areas

The City of Auburn regulates six types of critical or environmentally sensitive areas, purusant to Washington State Law (RCW 36.70A.060 and WAC 197-11-908). Auburn City Code (ACC) Chapter 16.10 includes regulations for protecting and reducing and mitigating impacts to:

- Wetlands
- Streams
- Wildlife Habitat
- Aquifir Recharge Areas
- Geologically Hazardous Areas
- Flood Hazard Areas

4.1 Current Conditions

This section identifies the critical and environmentally sensitive areas that are on the site, as well as describes additional aspects of the natural environment of the City of Auburn Downtown Plan study area that may be considered as the plan develops.

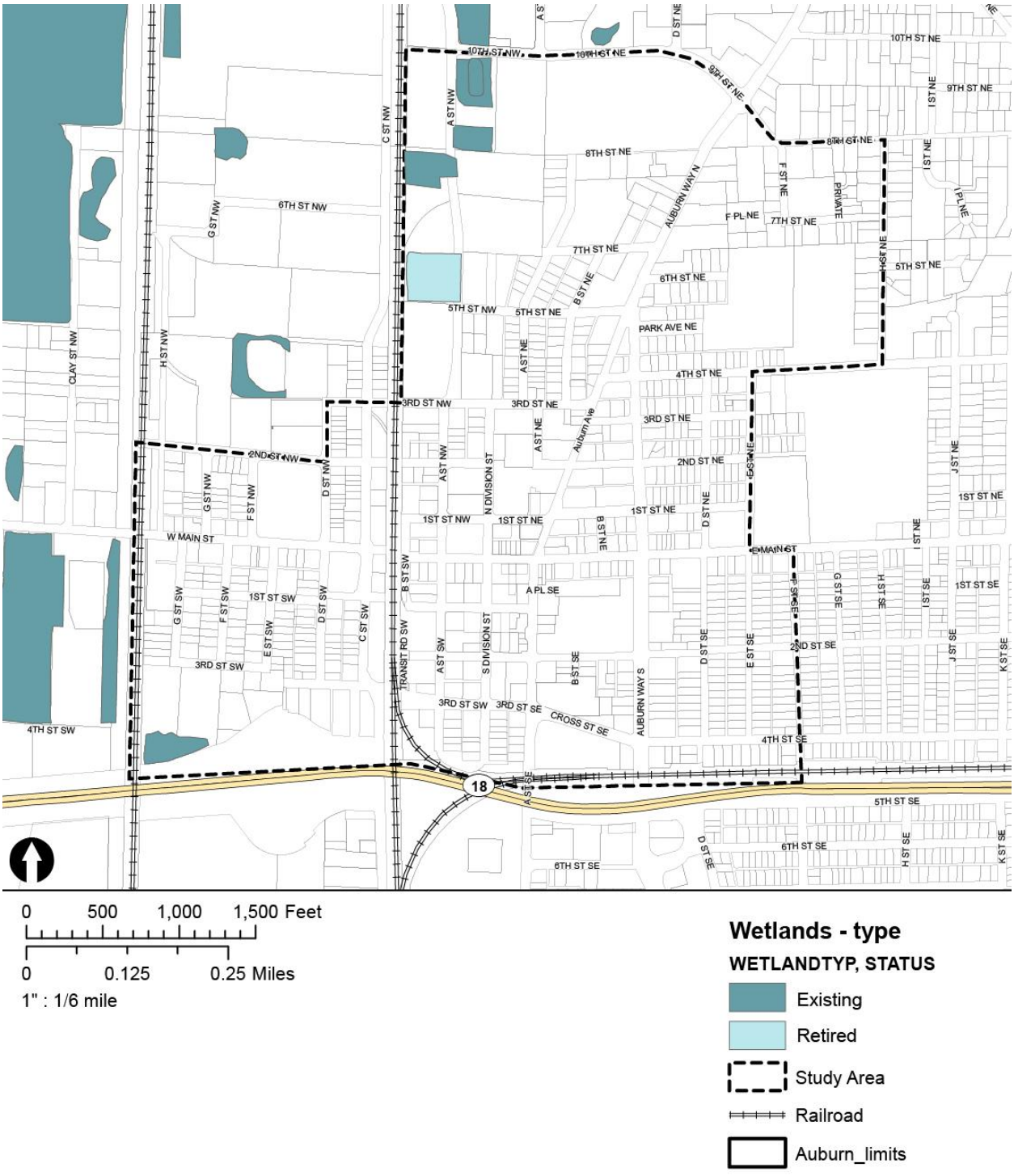
Wetlands, Streams, and Wildlife

WETLANDS

There are wetlands present within the study are in two general locations. North Downtown, adjacent ot the A St NW corridor, and in West Downtown in the very SE corner of the study area,

adjacent to SR 18. Exhibit ZZ illustrates the locations and categorization of each wetland. Identifieion of these critical areas is based solely on City GIS resources – no field investigations have been made to further delineate the boundaries of these wetlands. All the wetlands in the subare are located on heavily developed land, on or adjacent to industrial land uses and/or highway corridors.

FIGURE 4-1 Map of Existing Wetlands



SOURCES: City of Auburn GIS Data, MAKERS

STREAMS

No existing streams are shown within the City of Auburn Downtown Plan study area on the City's online GIS map or the King County Critical Areas online GIS map.

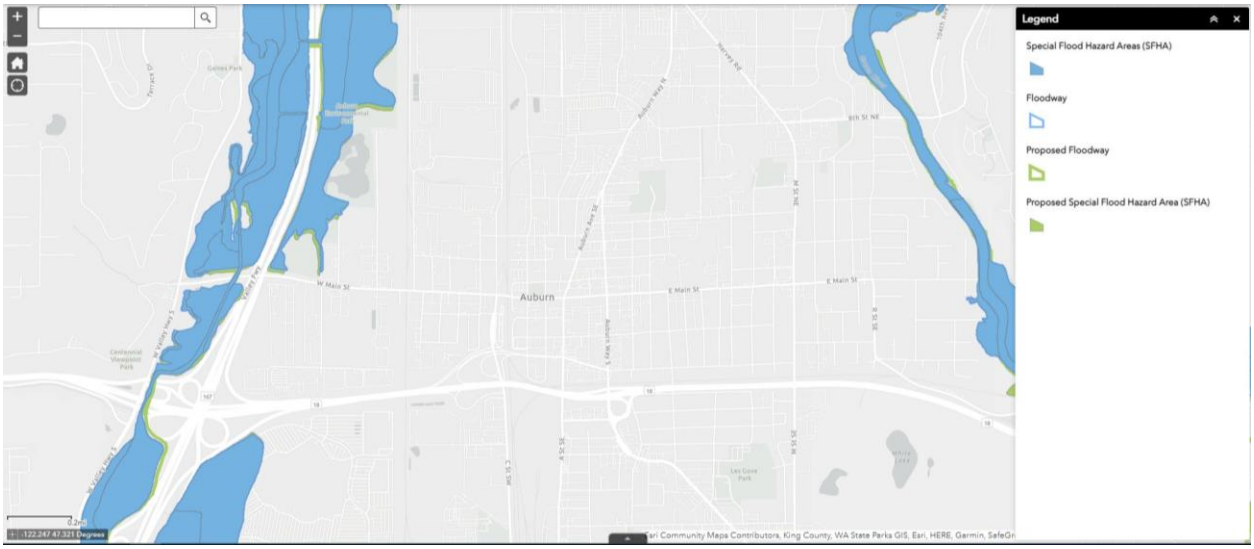
WILDLIFE

Given the highly developed context of Downtown Auburn, there is limited current opportunity for wildlife habitat. Some wildlife are likely present in existing wetland areas but there are no fish-bearing streams or habitat areas mapped by City or King County in the study area.

Flood Hazard Areas

No existing flood hazard areas are shown within the City of Auburn Downtown Plan study area, though there are some mapped flood hazard areas to the east along 167 and the Auburn Environmental Park.

FIGURE 4-4-2 Existing FEMA Flood Hazard Map

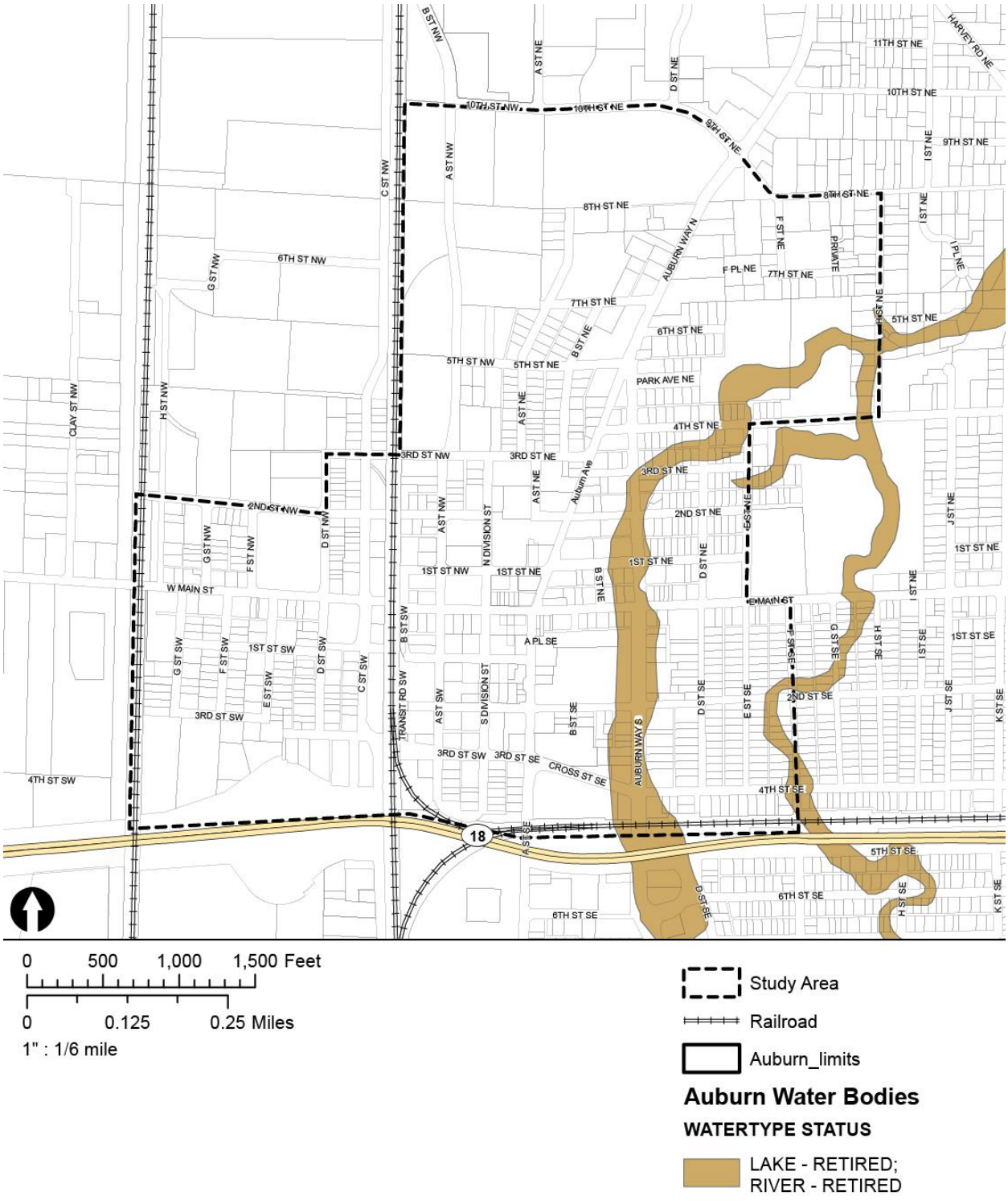


Source: City of Auburn Interactive GIS Map

Flood Historic River flows

The land on which downtown Auburn is located was shaped by the historic flows and flood patterns of the Green and White Rivers. The Green and White River Valleys were once active floodplains, prone to periodic flooding and channel migrations. Prior to 1906 the White River flowed through Downtown Auburn, along the general alignment of today's Auburn Way S corridor. A major flood in 1906 permanently changed the course of the White River, which allowed for the development of downtown Auburn in the early 20th Century. The construction of the Howard Hanson Dam further regulated river flows in the area, protecting Green River Valley communities from repeated flood risk.

FIGURE 4-3 Historic river flows through Downtown Auburn



SOURCES: City of Auburn GIS Data, MAKERS

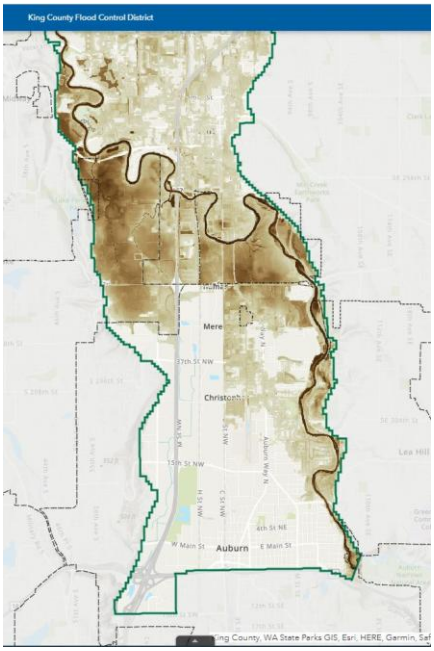
ADDITIONAL FLOOD INFORMATION

Lower Green River Flood Hazard Mitigation Plan

The King County Flood Control District is currently preparing a Lower Green River Corridor Flood Hazard Management Plan to address flood hazard challenges for communities along the Lower Green River. The Study Area for that plan includes Downtown Auburn. However, interactive maps developed for the study's EIS show no elevated flood risk for areas within the City of Auburn Downtown Plan study area boundaries.

The King County Flood Control District is currently studying flood control options for the Lower Green River Valley. The study area for the project includes downtown Auburn. However, the sites interactive map does not show an elevated flood risk for the area.

FIGURE 4-4 Lower Green River Flood Hazard Management Plan



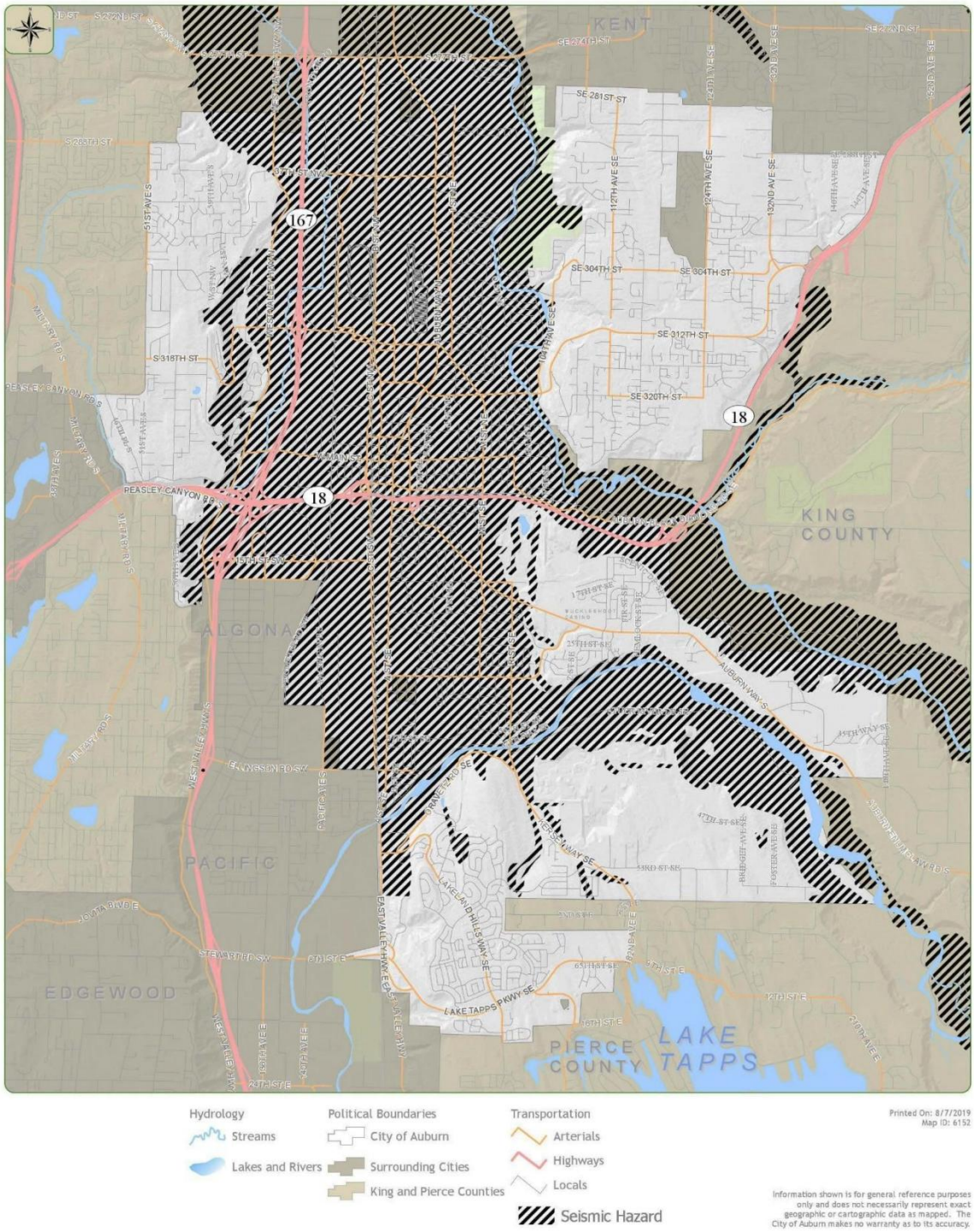
SOURCES: King County Flood Control District, Lower Green River Corridor Flood Hazard Management Plan.

Landslide, Geologic Hazards, and Volcanic Hazards

No existing landslide hazards or critical aquifer recharge areas are shown within the City of Auburn Downtown Plan study area on the City's online GIS map or the King County Critical Areas online GIS map.

The City of Auburn, like communities throughout the Puget Sound Region, is susceptible to major earthquakes. The soils throughout the study area are at a high-risk of liquefaction in the event of an earthquake. Older buildings, particularly unreinforced masonry structures, can be particularly susceptible to earthquake damage.

FIGURE 4-5 Seismic Hazards



Source: 2019 Auburn Plan Annex – King County Mitigation Plan

Past eruptions of Mt. Rainier have resulted in lahar flows that impacted the Auburn Area. Downtown Auburn is just north of the lahar risk area, but is within an area that could be impacted by sediment and post-lahar flooding. (Auburn Hazard Mitigation Plan)

Air Quality

Air quality is likely degraded in the are due to the present of two industrial rail corridors that run through or adjacent to the site, as well as a number of regional highways and local arterial streets that produce fine particle emissions.

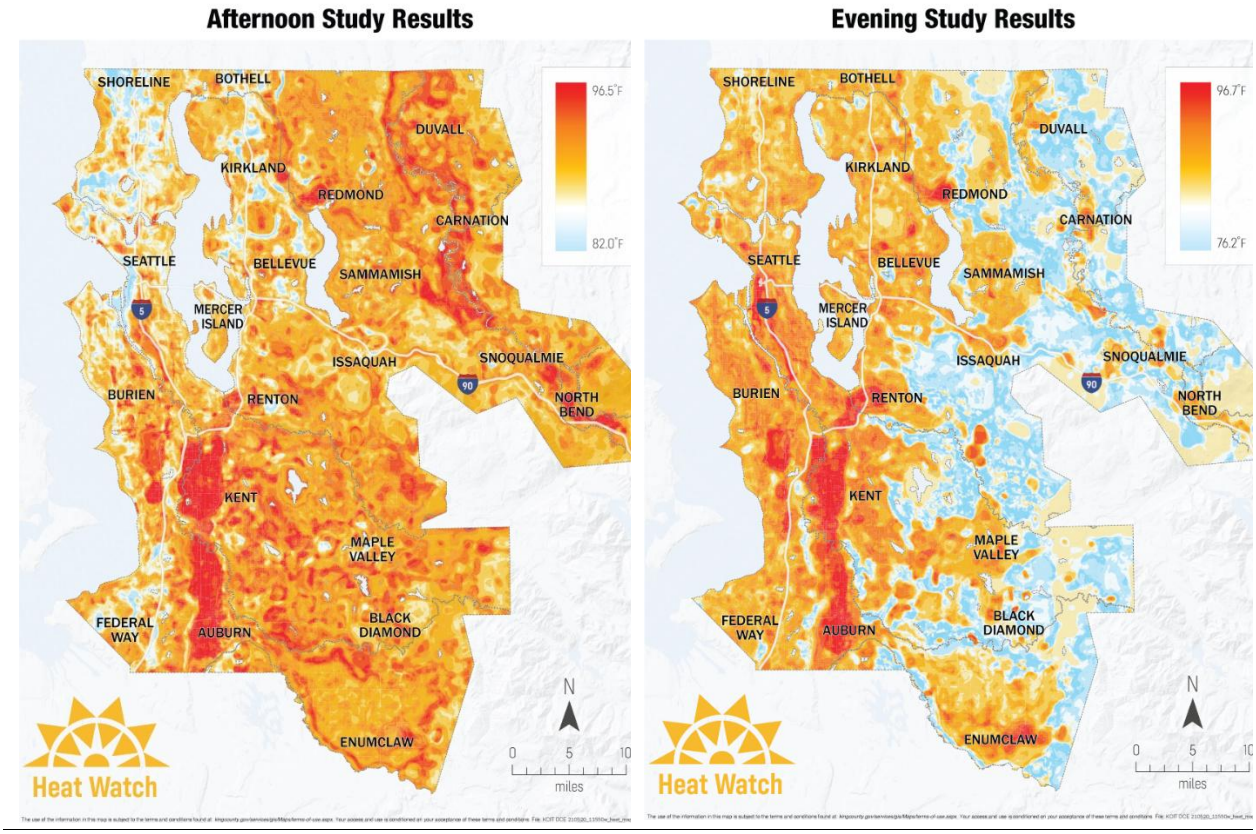
Climate Change

Climate change has had an increased impact on the City of Auburn in recent years, resulting in extreme heat, increased wildfire risks and smoke exposure, and changes in precipitation patterns.

EXTREME HEAT

Recent research by King County Public Health illustrated the impacts of urban heat on the region, which highlighted clear hot-spots in Green River Valley communities. Exhibit XX below shows that while heat is relatively distributed during the day, developed and industrial areas with lots of impervious surface cover retain heat into the evening much longer than communities with more tree canopy cover and green space. King County Public Health is now developing a heat mitigation strategy, which will include funding and strategy resources to help communities address urban heat impacts.

FIGURE 4-6 Urban Heat Mapping Results (KC Public Health)



SOURCES:King County Public Health, Heat Mapping Project
(https://kingcounty.gov/depts/dnrp/newsroom/newsreleases/2022/June/24-extreme-heat-mitigation-strategy.aspx)

4.2 Key Findings and Implications for Plan

- There are wetlands present on highly developed properties within the study area. These natural elements could provide an opportunity to enhance ecological conditions in the subarea, if the plan explores redevelopment and new land uses adjacent to these areas.
- Downtown Auburn does not appear to be at elevated risk from riverine flooding, though stormwater flooding may present some challenges.
- Air pollution sources from arterial and rail corridors should be considered when locating new housing.
- Highly developed context of downtown Auburn limits natural environment processes wthin the study area. Redevelopment could offere opportunities for green stormwater infrastructure, urban trees canopy cover, parks and green open spaces, and other elements of green infrastructure.
- Urban heat is a challenge for the Downtown area. Lack of shade lead to higher temperatures, which can be very challenging for vulnerable populations (seniors, low-income, etc.)

SECTION 5 HOUSING AND SOCIOECONOMICS

This chapter describes existing housing and socioeconomic conditions and adopted Comprehensive Plan targets for the City of Auburn Downtown study area, based on available city, regional, state and federal data, and on adopted plans.

5.0 Existing Policies and Regulations

Housing Action Plan

The City recently completed a housing action plan, which included a number of recommendations relevant to the downtown and the study area:

- Objective – Encourage Market Rage Development Downtown
  - A1. Reduce Parking Requirements to Support Development in Downtown Auburn
  - A2. Offer a Density Bonus to Support Denser Residential Development and Mixed-Income Housing
  - A3. Promote Lot Aggregation in Downtown Auburn
  - A4. Explore Fee Waivers for Targeted Development Types in Downtown Auburn
- Objective – Encourage Affordable Housing Downtown
  - B1. Create Policies to Lower the Cost of Affordable Housing Development
  - B2. Consider a Voluntary Inclusionary Housing Program Paired with a Density Bonus
  - B3. Reduce Parking Requirements for Micro Units
- Objective – Encourage missing middle housing in R-7 zones.

5.1 Population

Downtown Population and Comparisons

Table 5-1 shows 2022 data on downtown Auburn's population and households compared with other South Puget Sound comparison downtown areas. Many of the characteristics of downtowns discussed above apply to both Auburn and the comparison downtown areas, including **small**

household size, smaller than regional shares of family households and a larger share of renters. Notably, Auburn's downtown has grown considerably more quickly than the comparison downtown areas since 2010.

TABLE 5-1 Auburn Downtown Population and Households With Regional Comparisons (2022)

	Auburn		Comparison Downtown Areas			Counties		State
	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
2010 Population	2,313	70,389	1,799	3,328	4,097	1,931,269	795,205	6,724,540
2022 Population	3,352	89,746	2,072	4,288	5,052	2,334,990	944,204	7,895,191
Population Change 2010-2022	45%	28%	15%	29%	23%	21%	19%	17%
Households	1,529	31,564	925	1,722	2,420	944,171	347,698	3,046,982
Average H'hold Size	2.1	2.8	2.2	2.2	2.0	2.4	2.7	2.5
Family Households	44%	66%	44%	47%	47%	57%	66%	63%
Owners	18%	58%	12%	27%	30%	53%	61%	59%
Renters	73%	38%	83%	61%	66%	42%	33%	34%

Source: ESRI

5.2 Demographics

This section discusses the demographics of Auburn's downtown residents compared with the city as a whole and other regional comparisons. Understanding the demographics of the study area is important in considering the types of future housing and commercial development in the downtown.

Auburn's population when broken down by age is similar to many South Puget Sound municipalities, and to the county and statewide averages. **The population of the downtown study area is significantly older,** with 22 percent of residents over 65, compared with 15 percent citywide. This likely reflects the large number of senior housing in the area – 521 units in three multi-family developments.

TABLE 5-2 Auburn Downtown Age with Comparison Cities (2022)

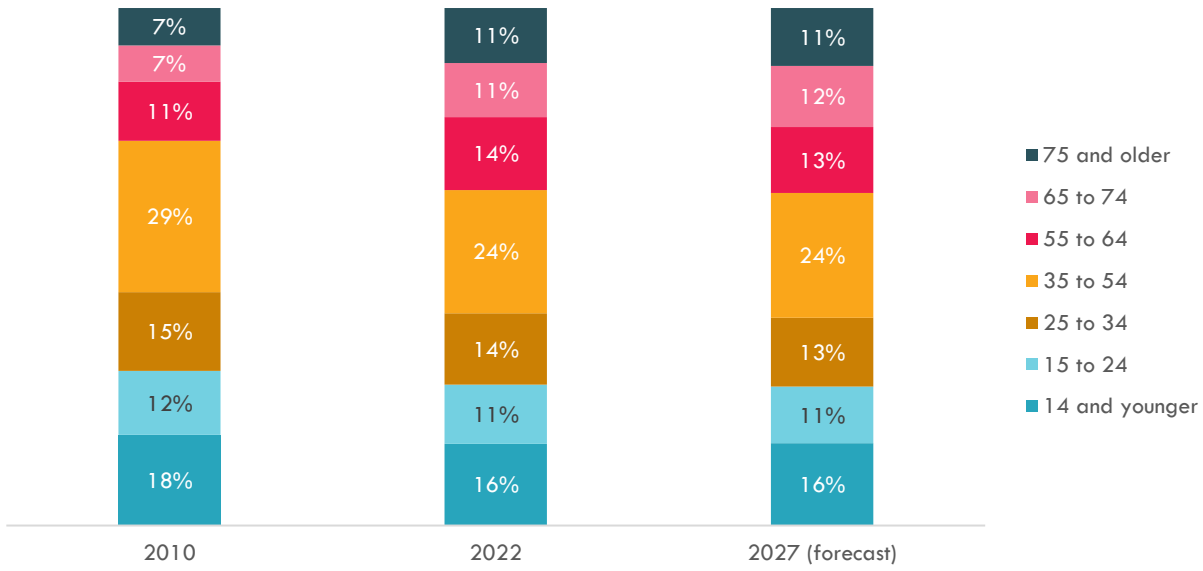
Auburn	Comparison Downtown Areas	Counties	State

AGE	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
14 and younger	16%	20%	20%	18%	16%	17%	19%	18%
15 to 24	11%	12%	10%	15%	10%	12%	13%	12%
25 to 34	14%	16%	14%	17%	15%	16%	15%	14%
35 to 54	24%	25%	23%	27%	27%	28%	25%	25%
55 to 64	14%	12%	11%	11%	14%	13%	13%	13%
65 to 74	11%	9%	10%	7%	11%	9%	10%	10%
75 and older	11%	6%	13%	6%	8%	6%	6%	7%

Source: ESRI

Figure 5-1 shows the historic, current and future forecast population by age in Downtown Auburn. **The study area population has aged significantly since 2010**, but the age distribution is projected to remain essentially consistent over the next five years. However, the overall higher age of downtown residents, propensity for downtown populations to skew older, and the aging of the Baby Boomer generation suggest the continued need for senior and accessible housing in the area.

FIGURE 5-1 Age of Auburn Downtown Population (2010-2027)



Source: ESRI

The racial and ethnic breakdown of Auburn's downtown residents is less diverse than the city as a whole, as shown in Table 5-3TABLE 5-1TABLE 5-3 Auburn Downtown Race/Ethnicity with Comparison Cities (2022) . Most notable is the smaller concentration of Asian populations downtown. Auburn's downtown area is also less diverse than Federal Way, Kent, and Burien's central areas. This is somewhat unusual in light of the trends towards more diversity in downtown areas discussed above.

TABLE 5-3 Auburn Downtown Race/Ethnicity with Comparison Cities (2022)

	Auburn		Comparison Downtown Areas			Counties		State
RACE/ETHNICITY	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
White Alone	56%	51%	35%	45%	54%	55%	64%	66%
Black Alone	9%	8%	19%	15%	6%	7%	7%	4%
American Indian Alone	2%	2%	2%	1%	2%	1%	1%	2%
Asian Alone	7%	14%	17%	12%	8%	20%	7%	10%
Pacific Islander Alone	4%	3%	4%	3%	1%	1%	2%	1%
Some Other Race Alone	11%	10%	13%	13%	13%	5%	5%	7%
Two Or More Races Alone	11%	12%	10%	11%	15%	11%	13%	11%
Hispanic / Latino	17%	19%	24%	22%	25%	11%	12%	14%

Source: ESRI

FIGURE 5-2 **Map Showing Race and Ethnicity in Study Area**



Source: MAKERS (2020 Census)

Downtown Auburn residents earn significantly less than the citywide median income, as shown in Table 5-4. Downtown household incomes in Auburn are similar to those in Federal Way, Kent, and Burien, and all of these comparison cities show lower incomes in their downtown areas than in the cities overall. Many of these cities, particularly Auburn and Federal Way, contain a large amount of senior housing in their downtown areas, which could partially account for this trend. Additionally, downtown Auburn contains a wide mix of housing types, from older single-family homes to new multifamily developments as discussed below in "Housing Profile," accounting for a wide range of incomes in the area. In addition, the smaller household size seen in the downtown area may partially account for this data, since a larger share of one-person households also equates to a larger share of single-income households. Overall, this data suggests the **need for a variety of housing price points in the downtown area, for existing lower-income residents as well as to cater to potential new residents across the income spectrum,** particularly considering the large gap between Auburn's downtown and citywide incomes and King County median incomes.

TABLE 5-4 Auburn Downtown Income with Comparison Cities (2022)

	Auburn		Comparison Downtown Areas			Counties		State
INCOME	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
Median Household Income	$52,838	$86,533	$45,781	$60,313	$57,398	$116,151	$87,553	$88,312

Source: ESRI

As discussed previously, educational attainment is also a key metric in downtown areas. Contrary to national trends, Auburn's current downtown population has a much smaller share of college-educated residents than the city as a whole, and then county and statewide averages, as shown in Table 5-5. **This reflects Auburn's character as a historically blue-collar city,** and downtown stakeholder focus groups conducted by the project team in July 2022 indicated community preferences for downtown revitalization and improvement while retaining Auburn's traditional smaller-town feeling.

TABLE 5-5 Auburn Downtown Educational Attainment with Comparison Cities (2022)

	Auburn		Comparison Downtown Areas			Counties		State
EDUCATIONAL ATTAINMENT	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
Less than 9th Grade	6%	4%	7%	5%	5%	3%	2%	3%
9th - 12th Grade, No Diploma	7%	6%	9%	8%	10%	3%	5%	4%
High School Graduate	32%	23%	27%	24%	19%	12%	23%	18%
GED/Alternative Credential	8%	7%	2%	11%	4%	2%	5%	4%
Some College, No Degree	20%	21%	24%	25%	22%	15%	23%	21%
Associate Degree	12%	11%	9%	10%	10%	8%	13%	11%
Bachelor's Degree	11%	21%	19%	11%	20%	33%	19%	24%

Graduate/Professional Degree	7%	9%	4%	7%	9%	23%	10%	15%

Source: ESRI

5.3 Housing Profile

This section discusses the existing housing stock in Auburn's downtown compared with the city and region. An analysis of existing housing trends can inform potential development, redevelopment, current and future residents, and understanding of Auburn's built environment and character.

Housing Stock

As shown in Auburn Downtown Housing Profile with Comparison Cities (2022) Table 5-6, downtown Auburn's housing stock is a mix of single-family and multifamily development. **About a quarter of the housing units in the study area are single-family homes**, primarily in the western and eastern quadrants. **Almost a third of housing units in the downtown are in large developments of 50 units or more**. The share of multifamily units in Auburn's downtown is much higher than that in the city as a whole, which is about half single-family homes. Like Auburn, Federal Way, Kent, and Burien have the majority of their downtown housing units in multifamily buildings. Federal Way has a particularly small share of single-family units in its core due to its newer and more suburban development patterns.

Also illustrated below is the **significantly higher age of housing in Auburn's downtown when compared with the region**. Almost a quarter of housing units downtown were built before 1940, compared with only 4 percent in the city as a whole. This reflects Auburn's longer history as a city at an important railway junction dating back to the early 20th century, compared with more recently incorporated suburban jurisdictions such as Federal Way and Burien, where only a small portion of housing units were built before World War II.

Also notable is the 14 percent of housing in Auburn's downtown which was built since 2014. This **faster pace of recent development** is greater than that seen city- and county-wide, and of the regional comparison downtown areas, only Kent has a similar share of houses built in the past decade. Recent downtown development will be discussed more thoroughly in Section 6.0, "Auburn Downtown Development Trends."

TABLE 5-6 Auburn Downtown Housing Profile with Comparison Cities (2022)

	Auburn	Comparison Downtown Areas	Counties	State

UNIT TYPE	Downtown	City	Federal Way	Kent	Burien	King	Pierce	Washington
1, detached	27%	52%	10%	32%	27%	53%	66%	63%
1, attached	3%	6%	3%	3%	2%	5%	5%	4%
2	7%	4%	1%	2%	1%	2%	3%	2%
3 or 4	11%	6%	5%	5%	7%	4%	4%	4%
5 to 9	7%	6%	17%	6%	14%	6%	5%	4%
10 to 19	6%	8%	18%	13%	14%	7%	5%	5%
20 to 49	7%	4%	10%	7%	12%	8%	3%	5%
50 or more	31%	7%	34%	31%	21%	14%	4%	7%
Mobile home	1%	7%	1%	1%	1%	2%	5%	6%
Boat, RV, van, etc.	0%	0%	0%	0%	0%	0%	0%	0%
AGE OF HOUSING								
Built 2014 or later	14%	6%	4%	15%	7%	6%	4%	5%
Built 2010 to 2013	1%	5%	5%	1%	0%	4%	4%	4%
Built 2000 to 2009	4%	18%	2%	1%	13%	13%	16%	15%
Built 1990 to 1999	12%	17%	34%	12%	6%	13%	18%	17%
Built 1980 to 1989	8%	15%	28%	13%	16%	14%	14%	13%
Built 1970 to 1979	10%	14%	15%	14%	17%	13%	15%	16%
Built 1960 to 1969	6%	13%	10%	14%	17%	12%	9%	9%
Built 1950 to 1959	15%	6%	2%	10%	13%	8%	6%	7%
Built 1940 to 1949	7%	2%	0%	4%	8%	5%	4%	5%
Built 1939 or earlier	23%	4%	0%	15%	3%	12%	10%	10%

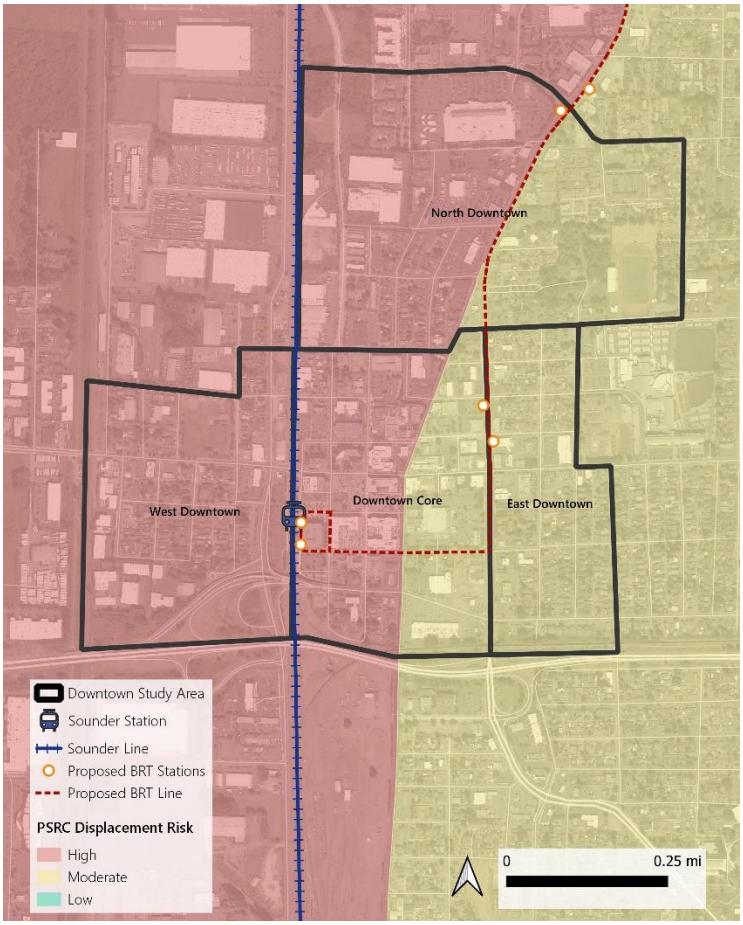
Source: 2020 American Community Survey 5-Year Estimates, ESRI

Displacement Risk

The Puget Sound Regional Council (PSRC) has taken steps to analyze and map displacement risk in the region. According to PSRC, "In the central Puget Sound region, communities of color, low-income households, small businesses, and renters are recognized as being at higher risk of displacement." To visualize and help plan to mitigate these pressures, PSRC developed five key categories of metrics which can be used to help identify populations at risk of displacement:

- **Socio-Demographic Indicators,** including race, ethnicity, linguistic isolation, educational attainment, housing tenure, cost burden, and household income
- **Transportation Indicators,** including access to jobs by car and transit and proximity to current and future transit service.
- **Neighborhood Characteristics,** including proximity to grocery stores, restaurants, parks, and schools

FIGURE 5-3 PSRC Displacement Risk in Auburn (2019)



Source: Puget Sound Regional Council, Sound Transit, King County, MAKERS

- **Housing Indicators,** including development capacity and rental costs
- **Civic Engagement,** measured by voter turnout.

PSRC developed a mapping tool which aggregates these indicators into high, medium, or low displacement risk areas. As shown in **Error! Reference source not found., the downtown study area is split between "high" and "moderate" risk areas, with much of North and all of West Downtown at high risk of displacement.** A recent meta-analysis of anti-displacement by researchers at UC Berkeley and UCLA found that neighborhood stabilization and tenant protection strategies in the short-term and the production of subsidized housing in the long-term

had the highest potential to prevent displacement.[4] **The downtown study area currently contains 426 subsidized affordable units** in several developments, slightly more than a quarter of the housing units in the area.

5.4 Employment Profile

This section discusses employment in Downtown Auburn, its major employers and sectors, and comparisons with Auburn as a whole and the region. It also discusses commuting patterns and changes in the downtown's economy over time.

Major Sectors and Employees

Table 5-7 shows the top employment sectors in downtown Auburn. As with many downtowns, **retail jobs make up the largest share of jobs in the study area**, at 21.6 percent. There are several large grocery stores including Safeway and Fred Meyer, numerous smaller retail jobs on Main Street, and a small shopping center in the core area. The health care sector accounts for another 20.5 percent of downtown jobs, and the **MultiCare is the largest employer in the study area with 635 employees**, as shown in Table 5-8. Other sectors with a high share of jobs in the downtown study area include Public Administration, due to the presence of Auburn's city hall, manufacturing, administration, accommodation and food service.

When compared with Auburn as a whole, the downtown has a higher share of retail, health care, and public sector jobs whereas the city's top sectors are more traditional blue-collar jobs in manufacturing, construction, and wholesale. **Regional comparisons illustrate differing trends in the South Sound**. In nearby Federal Way, retail makes up an even larger share of jobs in the town center area, which is centered around several malls and generally features more recent suburban development patterns. The presence of several hotels in central Federal Way near I-5 also makes up a large portion of downtown jobs there. In Kent, on the other hand, there is very little retail downtown, but instead there is a strong cluster of medical clinics, local and county government offices.

Overall, Auburn's downtown employment mix reflects its older development patterns, Main Street retail businesses, and the economic anchor provided by MultiCare. Leveraging the historic nature of downtown and Main Street and the strength of the medical sector will be key elements in downtown Auburn's future.

[4] Chapple, Karen and Loukaitou-Sideris, Anastasia. "White Paper on Anti-Displacement Strategy Effectiveness." Prepared for the California Air Resources Board. February 28, 2021.

TABLE 5-7 Top Employment Sectors in Auburn Downtown With Comparisons (2019)

	Auburn Downtown	Auburn City	Kent Downtown	Federal Way Town Center
Retail Trade	21.6%	10.6%	5.0%	41.6%
Health Care / Social Assistance	20.5%	5.1%	27.9%	12.8%
Public Administration	19.2%	3.9%	30.3%	0.0%
Manufacturing	12.6%	21.3%	1.8%	0.4%
Administration & Waste Management	6.4%	5.9%	13.4%	1.8%
Accommodation and Food Services	4.8%	4.7%	9.5%	30.8%
Finance / Insurance	2.8%	2.3%	4.6%	2.6%
Wholesale Trade	2.7%	9.8%	0.4%	0.6%
Other Services	2.7%	3.0%	1.1%	3.4%
Professional Services	1.6%	1.5%	1.6%	2.1%
Construction	1.4%	11.0%	1.2%	0.4%
Educational Services	1.3%	6.8%	0.6%	1.1%
Transportation / Warehousing	1.1%	6.9%	1.1%	0.0%
Information	0.6%	0.9%	0.8%	1.0%
Real Estate	0.5%	1.0%	0.7%	1.1%
Arts, Entertainment, and Recreation	0.1%	4.7%	0.0%	0.4%

Source: LEHD Census On The Map

TABLE 5-8 Top Ten Private Employers in Auburn Downtown Study Area (2020)

Employer	Employees	Share of all Downtown Jobs
MultiCare Auburn Medical Center	635	20%
Fred Meyer	320	10%
ProAmpac	240	8%
Safeway	90	3%
Trillium Employment Services	80	3%
Scarff Ford/Isuzu	74	2%
Auburn Dairy Products	70	2%
Merrill Gardens at Auburn II	59	2%
Cascade Orthopedics	50	2%
Oddfellas Pub & Eatery	47	1%
Total Jobs in Downtown Study Area	**3162**	**100%**

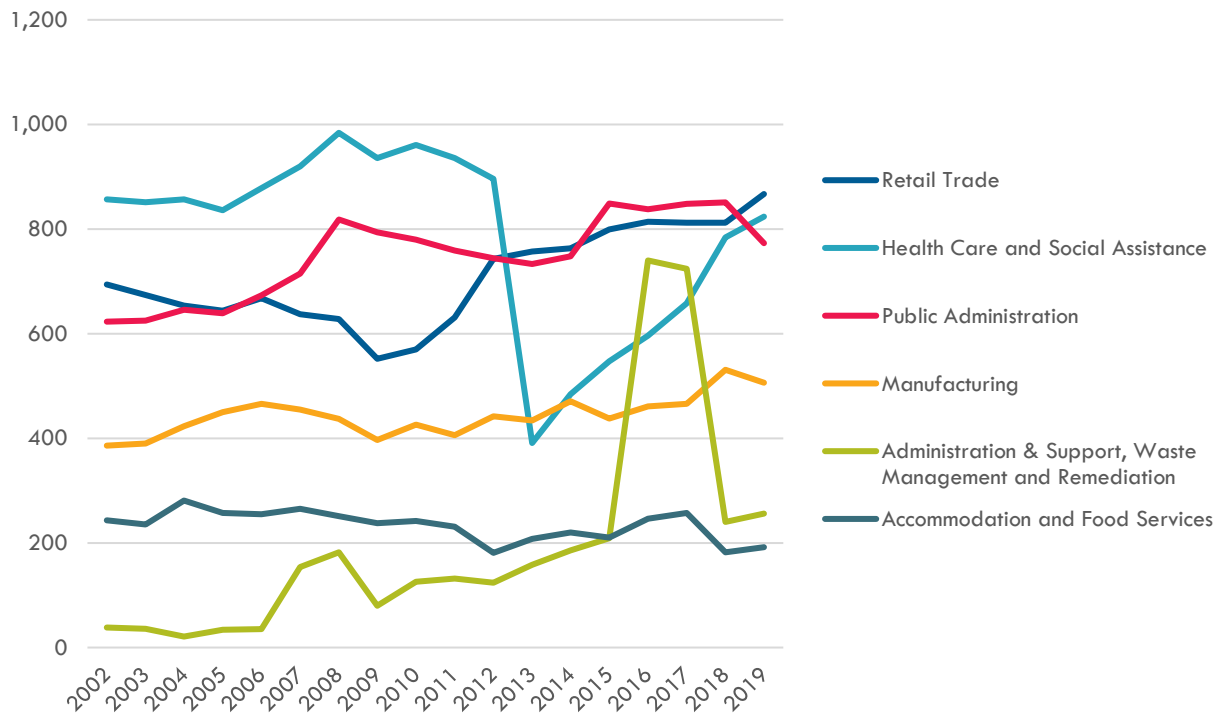
Source: City of Auburn Business License Data

Employment Change Over Time

Analyzing employment trends over time can shed light on potential changes in the downtown's economy.

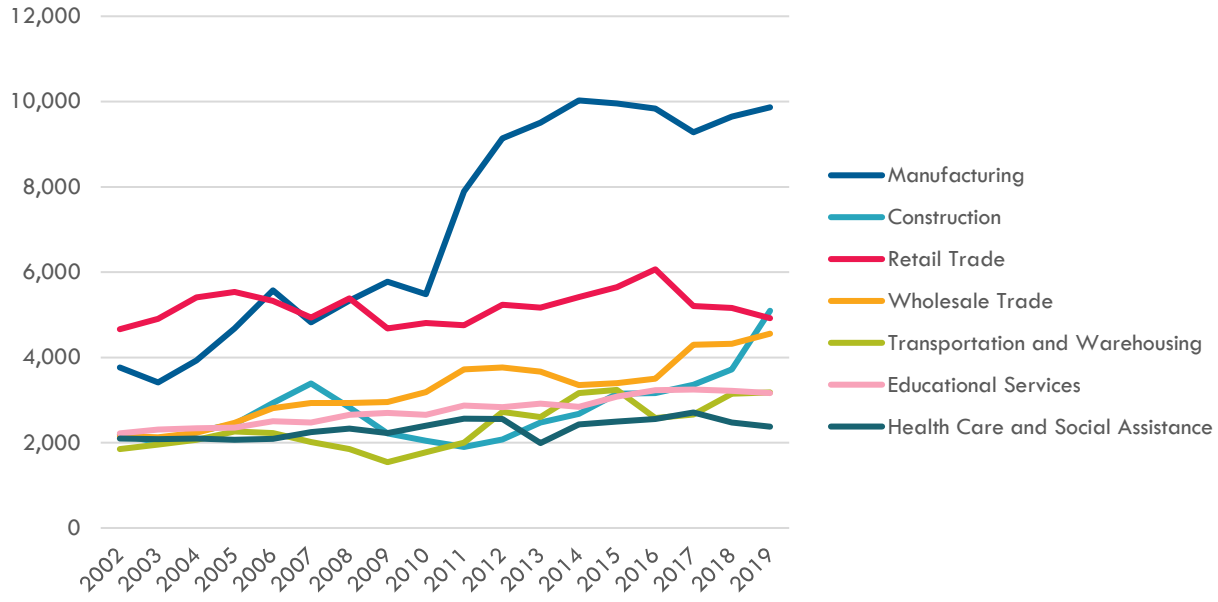
Figure 5-4 and Figure 5-5 show the change in employment for the top job sectors in the downtown study area and Auburn as a whole. Despite a loss of jobs around 2012, health care remains a major factor in the downtown as discussed previously. In fact, **most of the top employment sectors in the downtown area have remained relatively consistent over the past 20 years,** though with some fluctuations which may be due to Census data classifications. Auburn's citywide job mix has been dominated by manufacturing jobs over the past 20 years, which have increased remarkably from around 3,700 to around 9,800 jobs between 2002 and 2019. Other job sectors have remained relatively constant citywide, with recent notable increases in wholesale trade and construction.

FIGURE 5-4 Top Job Sectors in Auburn Downtown Study Area (2002-2019)



Source: Census On The Map

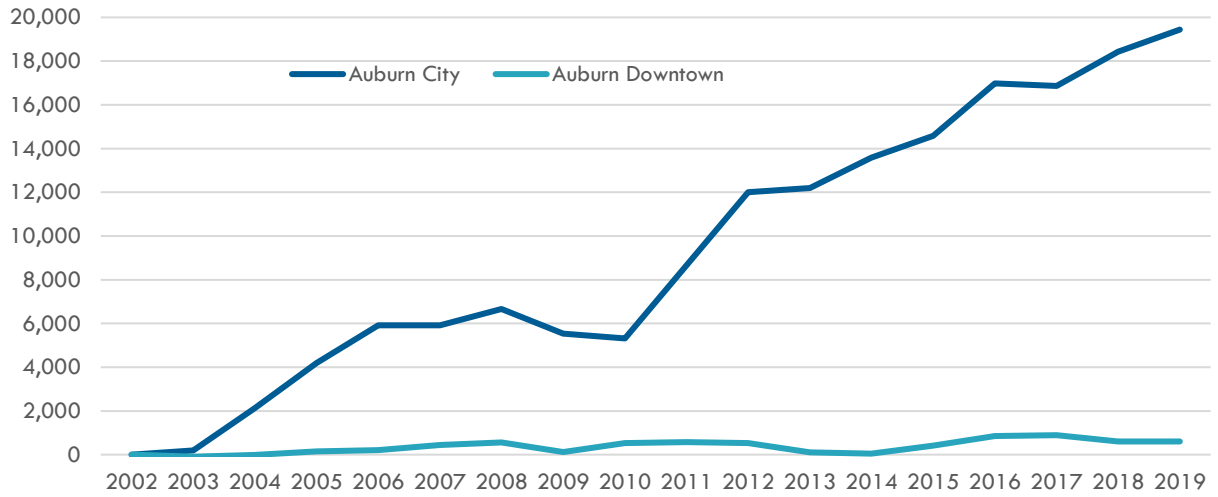
FIGURE 5-5 Top Job Sectors in Auburn City (2002-2019)



Source: LEHD, Census On The Map

The vast majority of job gains in the city have been outside of the downtown area, as shown in Figure 5-6. The downtown area accounted for about 9 percent of all jobs citywide in 2019, down from 13 percent in 2002. Although future development in the downtown may increase this ratio somewhat, it is notable that the majority of job growth has been in manufacturing and outside of the downtown area.

FIGURE 5-6 New Jobs since 2002 in Auburn and Downtown Study Area



Source: LEHD, Census On The Map

Commuting Patterns

The majority of employees in downtown Auburn do not live in the downtown area. As shown in Figure 5-7, about 1,432 employees per day who live in the downtown area commuted to jobs elsewhere and about 3,990 downtown employees commuted into the area. This data is from 2019, the most recent available Census commuting data, so it reflects pre-pandemic trends which have likely changed significantly. However, the data shows that downtown Auburn has a net influx of workers, as expected of a downtown area.

As of 2019, **about 11 percent of downtown employees lived in the city of Auburn**, with smaller numbers of employees commuting from Tacoma, Kent, Federal Way, and Seattle, as shown in Table 5-9. The remainder of downtown employees commuted from other municipalities, showing the wide range of commuting patterns in the South Puget Sound area.

FIGURE 5-7 Commuting Patterns in Auburn Downtown (2019)



Source: LEHD, Census On The Map

TABLE 5-9 Home Location of Auburn Downtown Employees (2019)

Home Location	Share
Auburn	11.0%
Tacoma	7.7%
Kent	5.7%
Federal Way	4.7%
Seattle	3.4%
All Other Locations	67.4%

Source: LEHD, Census On The Map

5.5 Key Findings and Implications for Plan

- Auburn's population has grown significantly since the 1980s. PSRC forecasts a population increase of about 20 percent for the next two decades in Auburn.
- Auburn's downtown has smaller household sizes, smaller than shares of family households and a larger share of renters than the city overall, typical of downtown patterns nationally.
- The population of the downtown study area is significantly older than the citywide population and contains a number of large senior housing developments.
- About a quarter of downtown housing units in the study area are single-family homes, and a third of housing units are in large developments of 50 units or more.
- The downtown study area population is classified by PSRC as having moderate to high risk of displacement due to redevelopment.
- Auburn is a historically blue-collar city and the majority of jobs and of job growth in the past 20 years has been in manufacturing, though few of these jobs are in the downtown area. The downtown area accounts for around 9 percent of all jobs in the city.
- Retail jobs make up the largest share of jobs in the study area, at 21.6 percent. The health care sector accounts for another 20.5 percent of downtown jobs, and MultiCare is the largest employer in the study area with 635 employees.
- The majority of employees in downtown Auburn do not live in the downtown area.

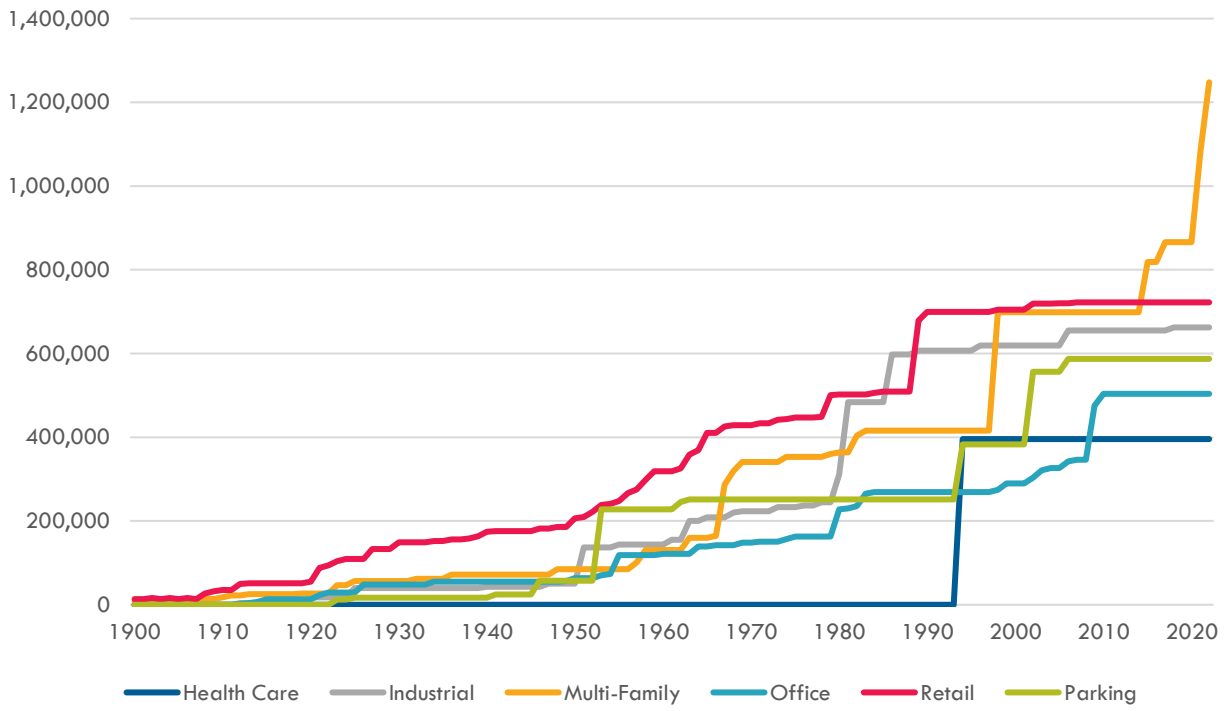
SECTION 6 ECONOMICS

This chapter describes existing economic activities, market conditions, policies and regulations related to economic development, and identified findings and implications for the Subarea Plan.

6.0 Auburn Downtown Development Trends

Downtown Auburn has a relatively long history compared with many South Sound municipalities, due to its location at an early important railway junction. Figure 6-1 shows the development patterns over time since 1900. Retail has always made up a large share of the building area, with steep increases in space devoted to parking seen in the post-WWII years and again in the 1990s. Office development has also increased consistently over time, particularly with the development of the medical center in the 1990s. Recent trends move away from new retail development and towards more industrial and multifamily development, particularly since 2000.

FIGURE 6-1 Square Feet (RBA) of Development in Study Area since 1900

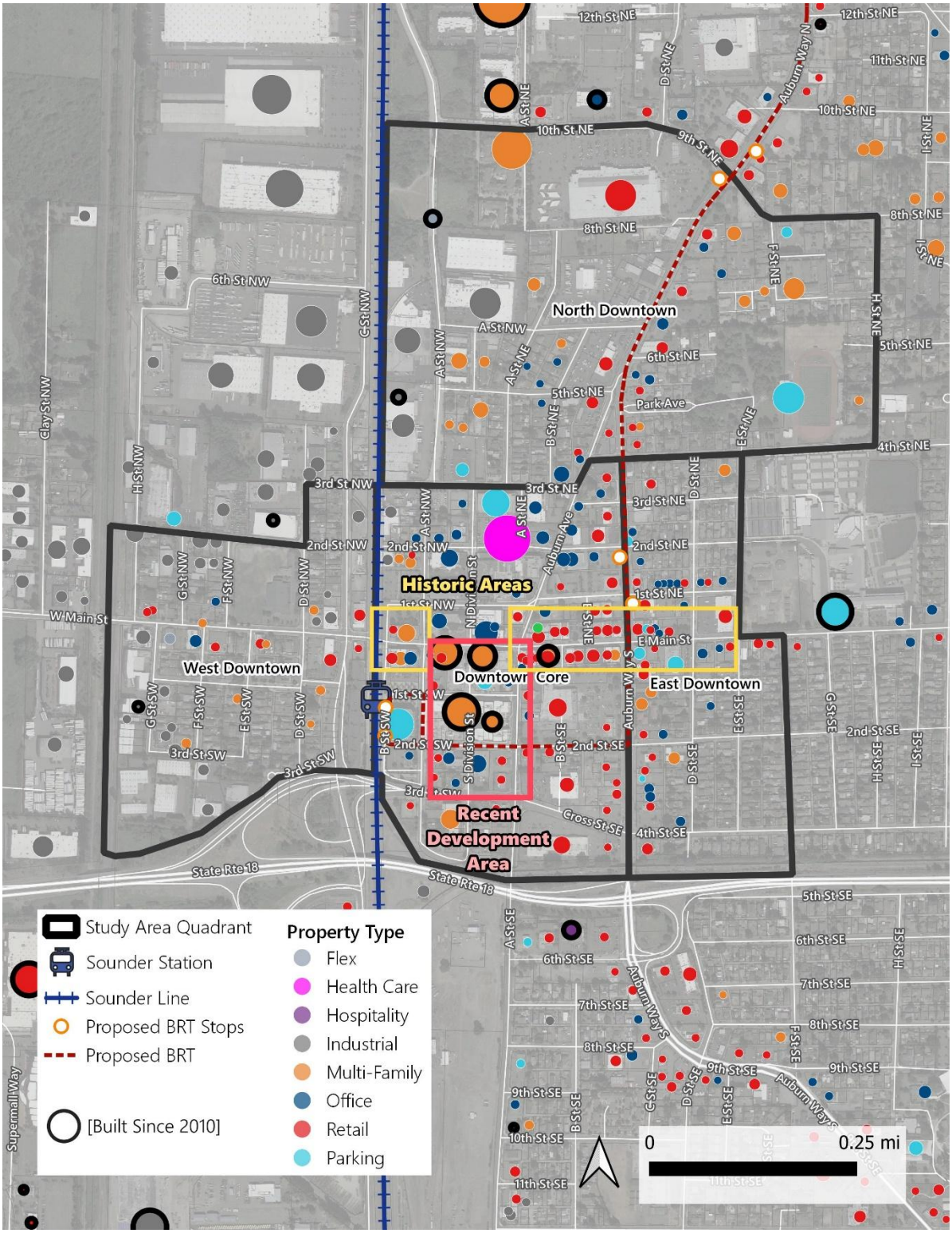


Source: Costar

Figure 6-2 shows downtown development spatially, with more recent developments highlighted in black. The yellow boxed areas contain many of Auburn's historic stores and buildings, a unique

asset of the downtown. **Most recent development has taken place within the pink area, a small part of the downtown core, and the majority of the development has been housing over some ground floor commercial space.** MultiCare, the downtown's largest employer, is the large purple dot in the center of the study area.

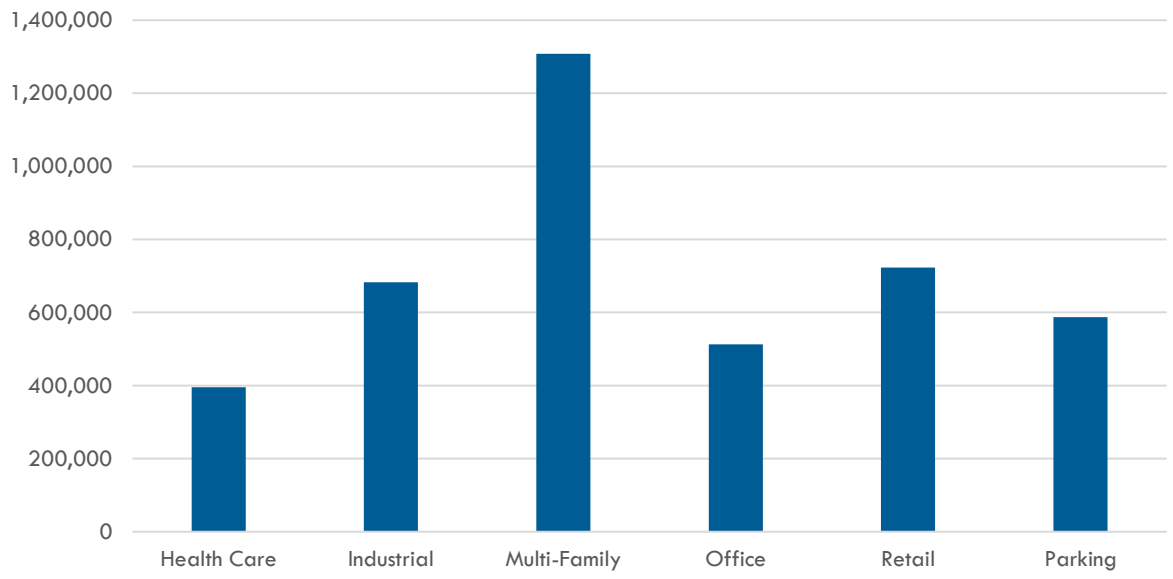
FIGURE 6-2 Development Type and Age in Study Area



Source: Costar

When considering building types in the study area, **multifamily units make up by far the largest amount of square footage in the downtown,** followed by industrial and retail uses. Parking lots are also a substantial use in the downtown, as well as health care as discussed above.

FIGURE 6-3 Total Square Footage (RBA) by Building Type in Study Area

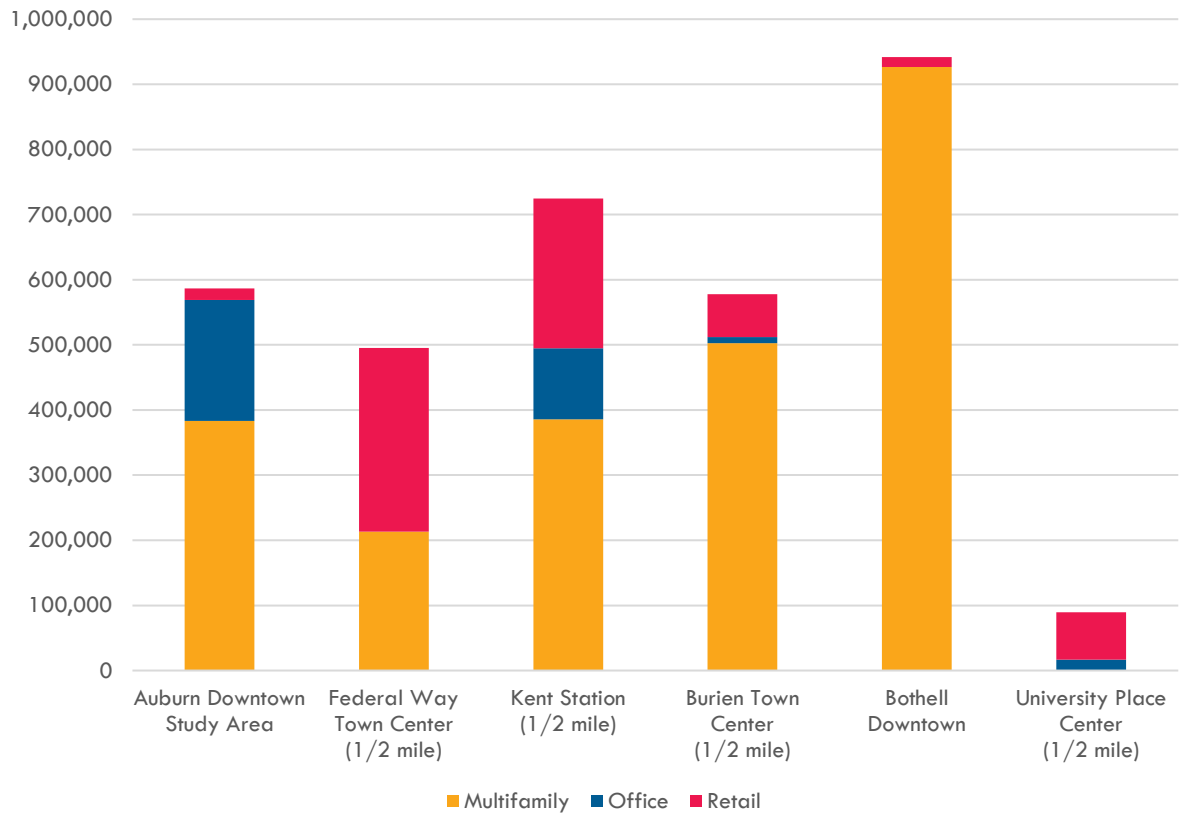


Source: Costar

Regional Comparisons

Figure 6-4 shows downtown Auburn's development patterns compared with regional comparison areas. The majority of development in the past 20 years in the South Sound area has been multifamily development, with some retail also built in Federal Way and Kent. **Auburn is clearly an outlier in the quantity of office development seen in the past two decades, particularly considering the overall decline in office demand.** (For more information see Appendix A – Market Study - Section 3)

FIGURE 6-4 Multifamily, Office, and Retail Development (RBA) 2002-2022



Source: Costar

Table 6-1shows the details of the office developments in Auburn's downtown constructed since 2002 and demonstrates that downtown Auburn's large quantity of recent office development is anchored in health care and the public sector.

TABLE 6-1 Downtown Auburn Office Development with Tenants, 2002-2022

Building	Address	RBA	Tenants
Armory Office Bldg	602 W Main St	13,416	Public School Employees of Washington
Auburn Medical Plaza II	121 N Division St	41,311	MultiCare Medical Offices
One Main Street Professional Plaza	1 E Main St	88,000	City of Auburn, Medical Offices, Key Bank, Chocolate Manufacturer
The Truitt Building	102 W Main St	17,460	Pub, Wholesale Distributor, Law Firm, Management Company
122 3rd St NE	122 3rd St NE	25,286	Medical Offices
310 6th St NE	310 6th St NE	5,319	Medical Offices
724 Auburn Way N	724 Auburn Way N	3,888	Business School

Source: Costar

Health care is a leading sector nationally and has been shown to be a strong driver of economic development. A study by the Brookings Institution found several key factors that health care jobs can bring to cities:

- Medical facilities bring **new income** to a metropolitan area by bringing in residents who would not otherwise come to the area
- Medical jobs **raise residents' earnings** by improving their skills
- Medical research **spurs metropolitan economic development** by fostering creation of new businesses and involvement with other businesses in the area
- Health care jobs pay **higher than average wage**s regardless of employees' skills and demographics[5]

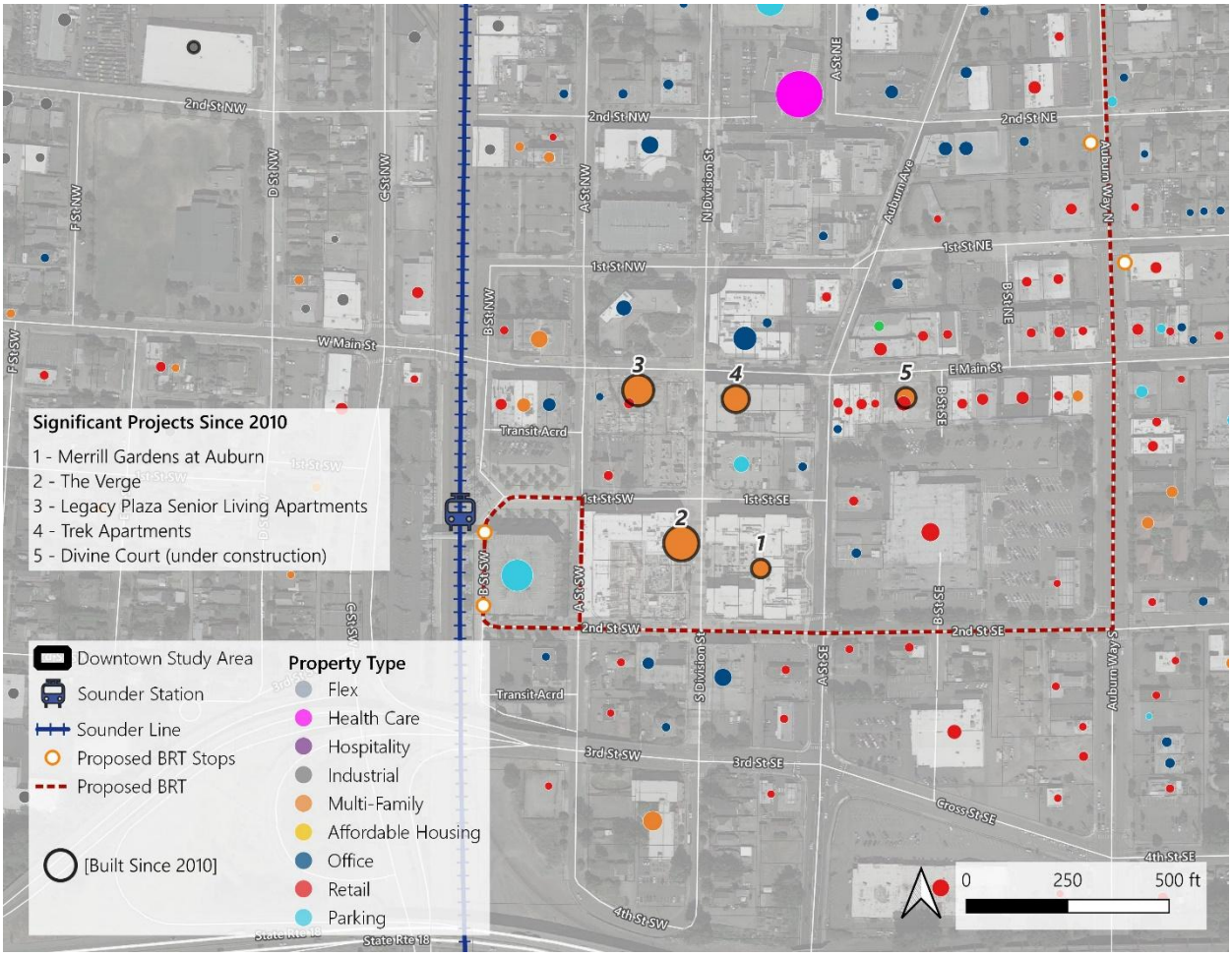
Overall, downtown Auburn's recent growth in health care jobs represents a positive investment in the future of the downtown economy. The hospital has recently announced plans to expand their facility in the next several years as well, with an additional 26,000 square foot pavilion with 24 hospital beds.

Recent and Upcoming Development

Figure 6-5 shows the Auburn downtown Core area, highlighting six significant projects built since 2010, which are detailed below. The majority of these are new multifamily developments, many of which are targeted towards seniors, as well as Auburn's recently completed City Hall.

[5] Bartik, Timothy and George Erickcek, "The Local Economic Impact of 'Eds & Meds,'" Metropolitan Policy Program at Brookings. December 2008.

FIGURE 6-5 Recent and Planned Significant Projects in Auburn Downtown Core, 2010 to 2024



Type	Name	Status	Year Built / Expected	RBA	Number of Units	Ground Floor Space
Office	City Hall (6)	Existing	2010	28,223	0	0
Multi-Family	Trek Apartments (4)	Existing	2015	120,000	126	2,400
Multi-Family	Merrill Gardens at Auburn (1)	Existing	2017	47,622	129	0
Multi-Family	The Verge (2)	Existing	2021	215,751	226	0
Multi-Family	Legacy Plaza Senior Living Apartments (3)	Existing	2022	166,000	166	0
Multi-Family	Divine Court (5)	Under Construction	2024	60,000	98	0

Source: Costar

1 – MERRILL GARDENS AT AUBURN



18 1st St. SE, Auburn, WA, 98002
Low-Rise Senior Apartments (***)
Year Built: 2017
Number of Units: 129
RBA: 47,622 sq. ft.
Land Area: 1.39 acres

2 – THE VERGE



109 S. Division St., Auburn, WA, 98001
Mid-Rise Senior Apartments (****)
Year Built: 2021
Number of Units: 226
RBA: 215,751 sq. ft.
Land Area: 1.44 acres

3 – LEGACY PLAZA SENIOR LIVING APARTMENTS



17 S. Division St., Auburn, WA, 98001
Mid-Rise Senior Apartments (****)
Year Built: 2022
Number of Units: 166
RBA: 166,000 sq. ft.

4 – TREK APARTMENTS



2 E. Main St., Auburn, WA, 98002
Mid-Rise Apartments (****)
Year Built: 2015
Number of Units: 126
RBA: 120,000 sq. ft.
Land Area: 0.72 acres

5 – DIVINE COURT



134 E. Main St., Auburn, WA, 98002
Mid-Rise Apartments
Year Built: 2024 (Under Construction)
Number of Units: 98
RBA: 60,000 sq. ft.
Land Area: 0.28 acres

6.1 Market Outlook

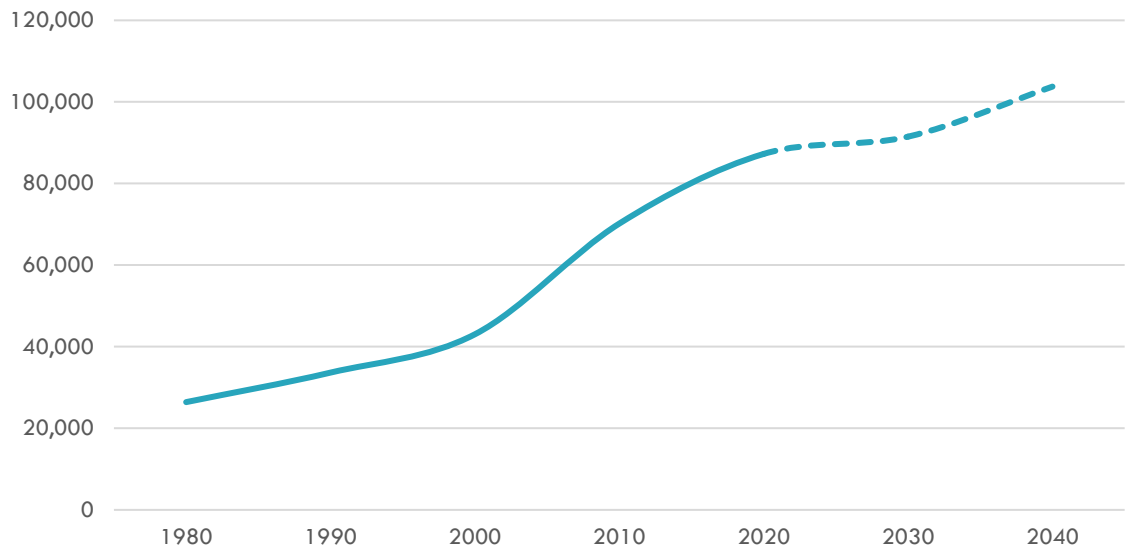
Housing

The market for multifamily housing in downtown Auburn can be judged by both long- and short-term indicators. Population growth trends and forecasts are useful indicators of long-term demand for housing in Auburn and its downtown.

Auburn's population has grown significantly since the 1980s, as shown in Figure 6-6. Population growth accelerated after 2000, with a 63 percent increase from 2000-2020 citywide, a rate of 3.6 percent per year. This outpaces King and Pierce Counties and the state, all of which grew at about 1.3 percent per year.

The Puget Sound Regional Council forecasts a **population increase of about 20 percent for the next two decades in Auburn,** in line with county and statewide projections, from a current population of 87,256 to a forecast 2040 population of 103,759. A portion of these new residents will live in Auburn's downtown, and the increased population will also be tied to increased employment opportunities in the downtown area.

FIGURE 6-6 Auburn City Population Growth and Forecast, 1980-2040

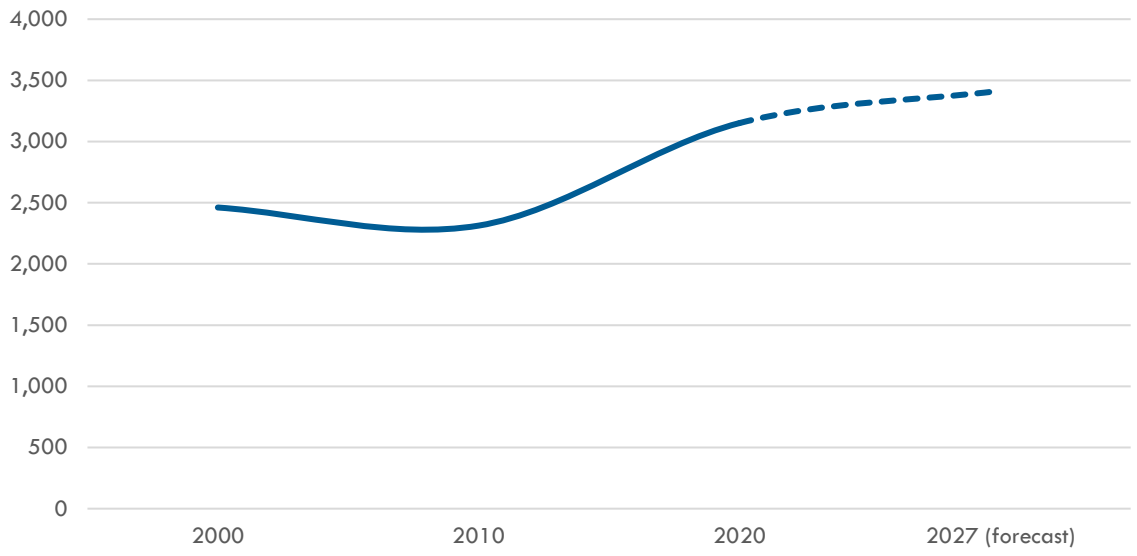


Source: Washington Office of Financial Management, Puget Sound Regional Council, Leland Consulting Group

The downtown area itself has a 2022 estimated population of 3,352, **an increase** of 45 percent from the 2010 population of 2,313. This rapid growth followed a decade of population stagnation from 2000 to 2010, when the downtown population decreased slightly from 2,461 to 2,313, as shown in Figure 6-7.[6]

[6] ESRI estimates for downtown study area population based on Census, Post Office, and other datasets, and downtown study area geography.

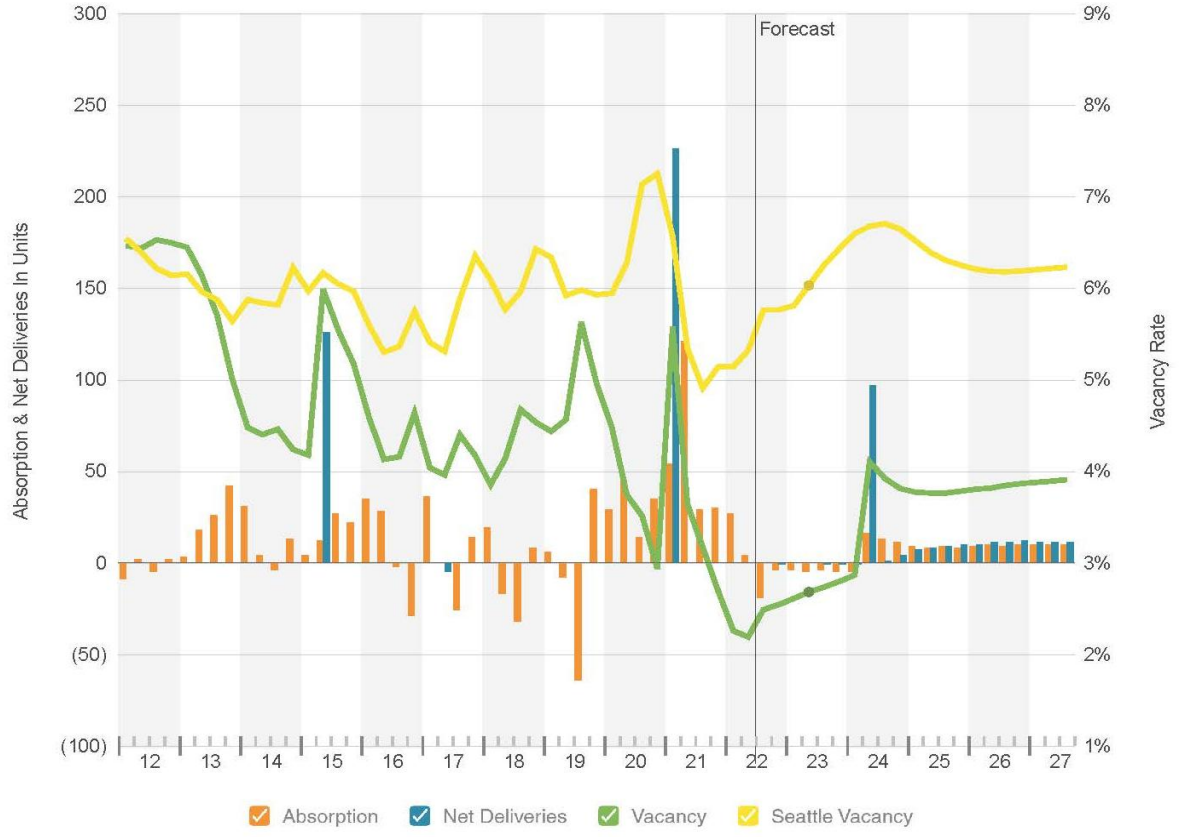
FIGURE 6-7 Downtown Auburn Study Area Population Growth and Forecast, 2000-2027



Source: ESRI

In the short term, the multifamily housing market in Auburn can be analyzed by recent construction, rental prices, and vacancy rates. There have been several multifamily developments constructed in recent years as discussed previously. As shown below in Figure 6-8, absorption has been strong, particularly since the onset of the COVID-19 pandemic, and vacancy rates are very low citywide – **Auburn is experiencing some of the lowest vacancy rates in the entire Seattle metro area,** currently reported by CoStar at 2.4 percent. CoStar further estimates that vacancy rates will remain well below Seattle's levels in the coming years, as shown below, though new units scheduled for completion in 2024 may ease the pressure somewhat.

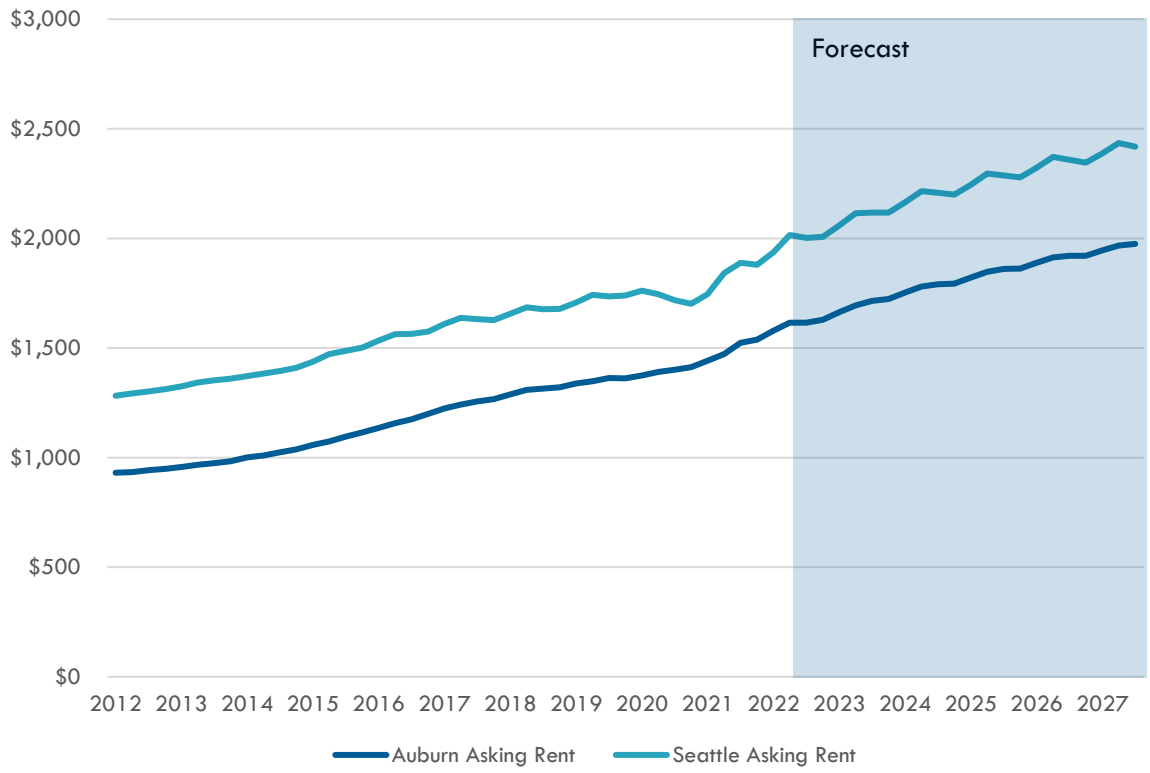
FIGURE 6-8 Absorption, Net Deliveries, and Vacancy in Auburn City, 2012-2027 (forecast)



Source: CoStar

Rents have also been increasing consistently in Auburn over the past decade, as shown in Figure 6-9. Although the average asking monthly rent of $1,628 is among the lowest in the Seattle area, **rents have increased by 7.3 percent over the past year,** decreasing the gap between Auburn and Seattle metro area rents. As shown below, CoStar forecasts that Auburn rents will continue to increase in the coming decade.

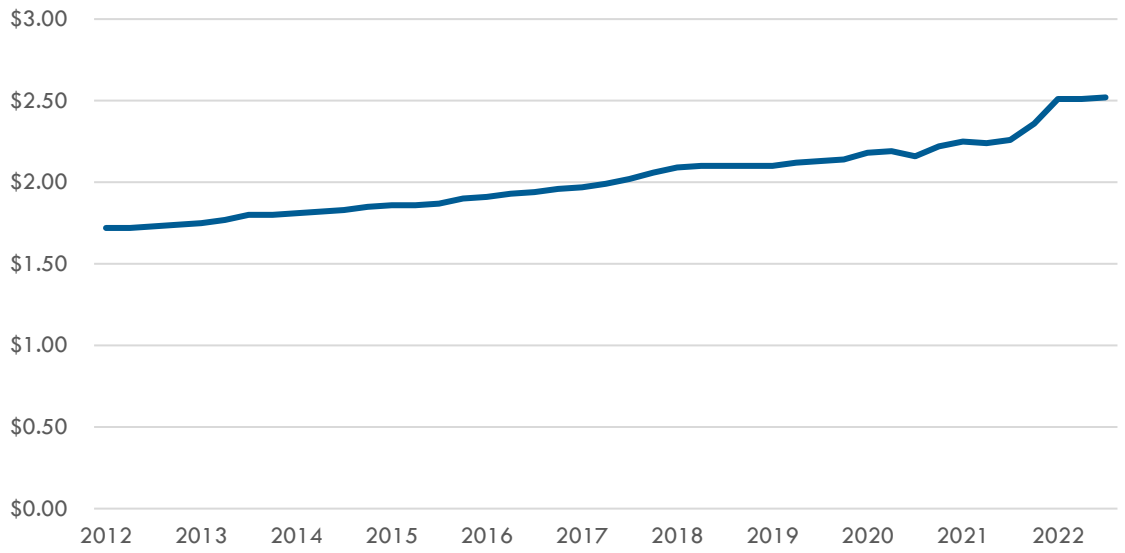
FIGURE 6-9 Auburn and Seattle Average Asking Rent, 2012-2027 (forecast)



Source: CoStar

The average Auburn citywide multifamily rent is currently $1.89 per square foot as of August 2022, up from $1.74 at the same time in 2021. **Market rents in the downtown study area are considerably higher, at $2.52 per square foot as of the second quarter of 2022.** As shown in Figure 6-10, rents in the study area have also increased significantly in the past year, after hovering slightly above $2.00 per square foot since 2018.

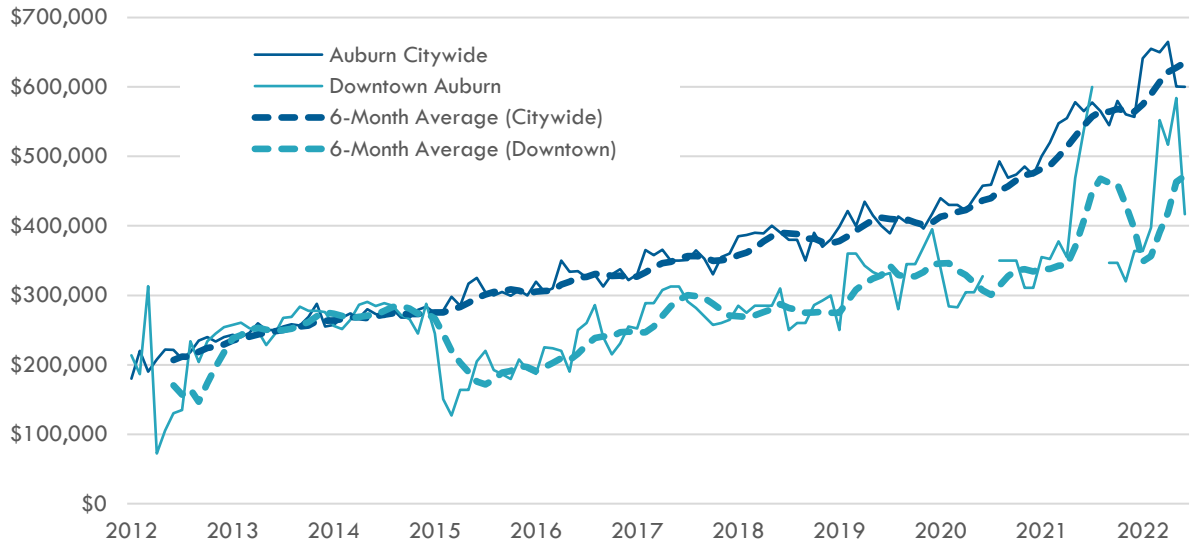
FIGURE 6-10 Market Asking Rents per Square Foot in Downtown Study Area, 2012-2022



Source: CoStar

Ownership housing costs have also been rising in recent years. As shown in Figure 6-11, sales prices in the downtown area have fluctuated significantly over the past several years but overall the trajectory is trending upwards, as with housing prices across Auburn, though the average downtown sales price is somewhat lower than citywide averages. Citywide, home prices are in the low $600,000 range and **downtown housing stock is selling for between $400,000 and $500,000 as of mid-2022.** The upward trajectory of housing prices has accelerated across the Puget Sound region since the onset of the COVID-19 pandemic in 2020 and Auburn is no exception, with **the average house citywide now selling for around $200,000 more than two years ago.**

FIGURE 6-11 Auburn Downtown Median Monthly Sales Price (2012-2022)

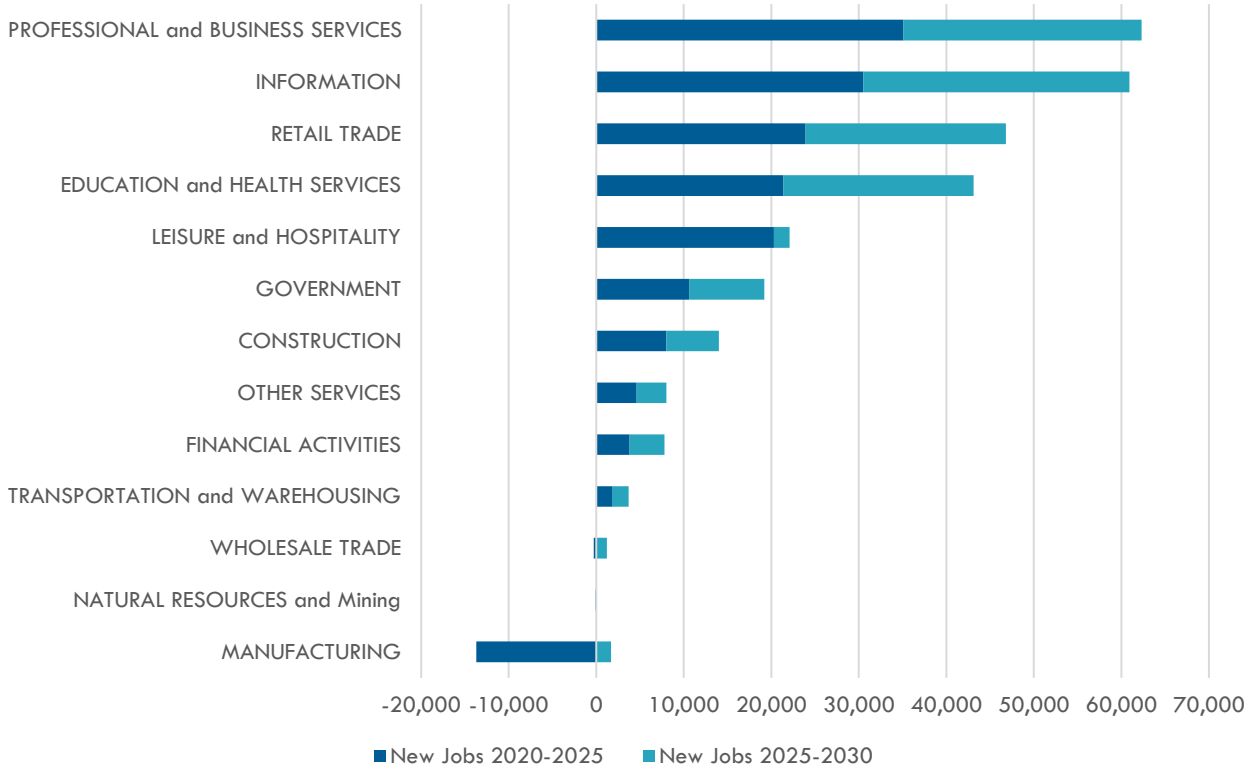


Source: Redfin Median Monthly Sales Price Data

Office

As discussed above in Section 6.0, Auburn has seen a greater quantity of office development than other South Sound comparison cities in the past several decades, driven by health care and public administration. Analyzing regional economic trends can help inform the long-term office market. Figure 6-12 shows the Washington Employment Security Department's forecast for new jobs by industry sector in King County through 2030. Although information and technology jobs are growing the fastest, driven by Seattle's dominance in tech industries, **health care and government are both expected to add significant numbers of jobs in the coming years regionally**. Auburn's existing cluster of medical facilities makes the downtown well positioned to take advantage of this regional trend. One example is the newly planned expansion of MultiCare discussed previously.

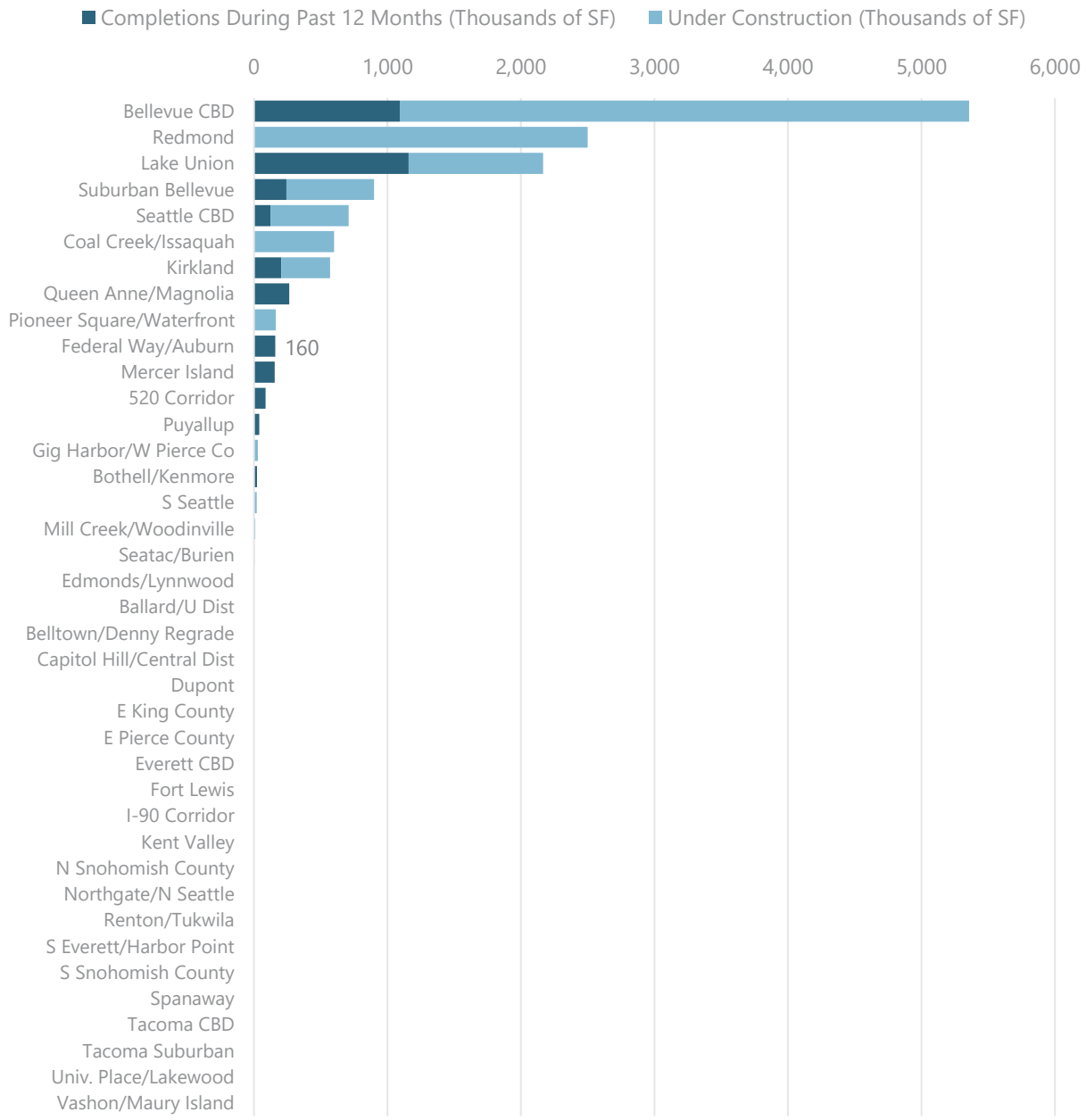
FIGURE 6-12 Number of New Jobs by Industry in King County, 2020-2030



Source: Washington Employment Security Department DATA

Despite these forecast job increases, the regional development trends shown below in Figure 6-13 suggest that the highest demand for new office space is in Seattle and eastern suburbs with agglomerations of jobs in technology. **The Federal Way/Auburn submarket has seen relatively little office development recently**. Overall, downtown Auburn is well positioned in the stability of its anchor employment sectors and although new development in the South Sound is relatively slow compared to the Seattle metro area overall, there is some potential in the office market in the long-term.

FIGURE 6-13 Office Development by Submarket, 2021

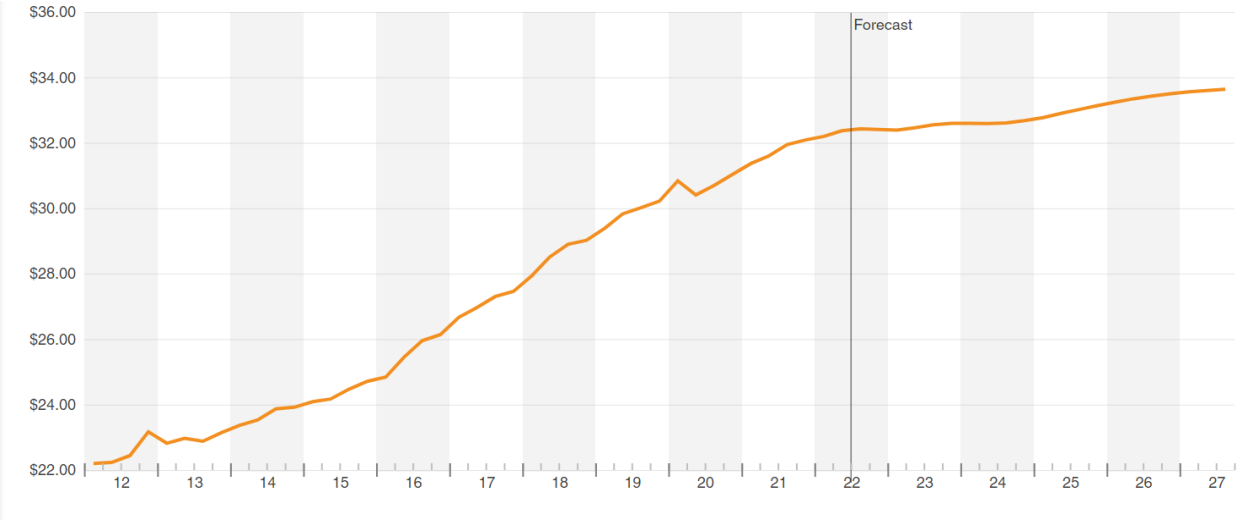


Source: CoStar

In the short-term, Auburn's office market has seen rents grow 2.3 percent over the past year, compared to 1 percent for the Seattle metro region overall, according to CoStar. Rents in the larger Auburn/Federal Way office market are about $29 per square foot, compared to $35 per square foot in the Seattle metro. In downtown Auburn, office market rents are somewhat higher

than the city overall, currently around $32 per square foot. CoStar forecasts office rents will stabilize in the coming years, increasing at a slower rate than the past decade, as shown below.

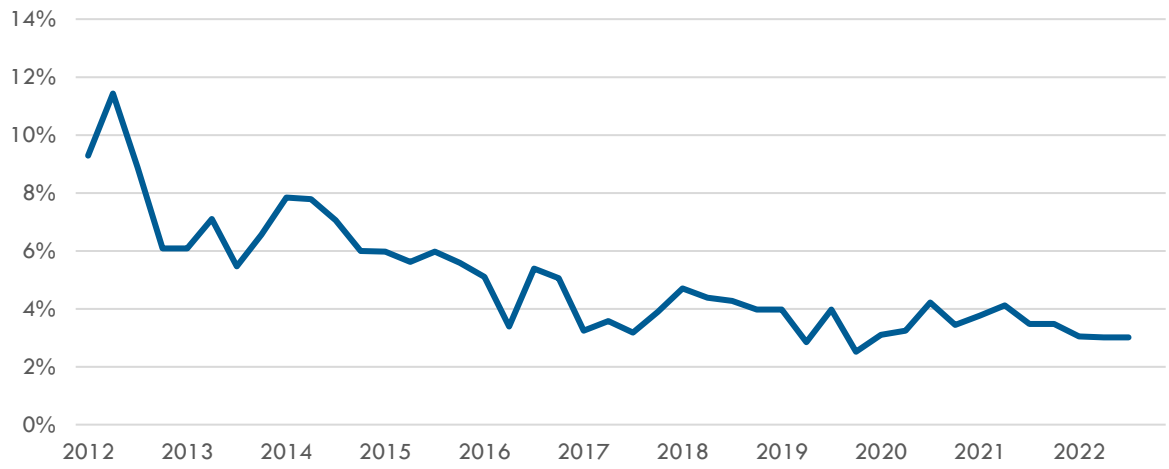
FIGURE 6-14 Office Market Rents per Square Foot, Auburn Downtown Study Area, 2012-2027 (forecast)



Source: Costar

The downtown Auburn office market has seen decreasing vacancy rates over the same period, corresponding with the increased rents per square foot shown above. Current vacancy rates are at 3 percent and have decreased in recent years as shown in Figure 6-15. Overall, this data suggests that **there has been demand for office space in the downtown area over the past decade, though regional development trends suggest this may stabilize in the coming decade.**

FIGURE 6-15 Office Vacancy Rate in Auburn Downtown Study Area, 2012-2022



Source: Costar

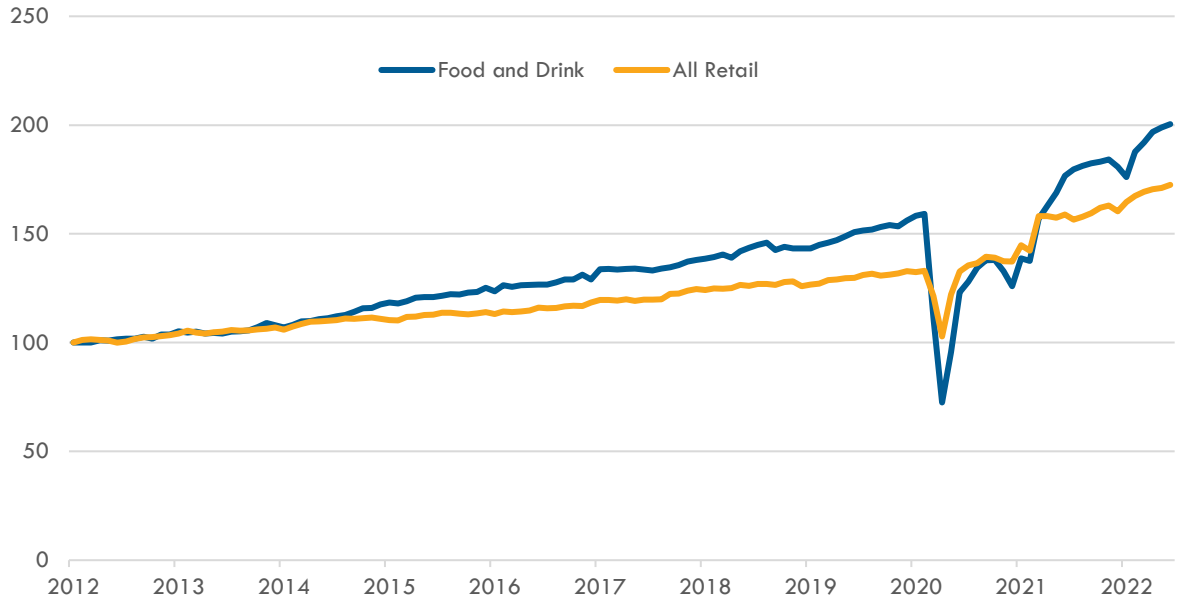
Retail

The nature of retail has been changing significantly in recent decades and even more rapidly since the onset of the COVID-19 pandemic in 2020. (For more background, see Appendix A – Market Study – Section 3.) Much of retail spending has moved online, particularly for hard goods and commodities that can be bought on the internet. Some retail sectors have had success in the past two years, particularly home improvement stores and discount stores, although these are unlikely to relocate to Auburn's downtown area. Other types of retail, such as apparel stores and office supplies, are also unlikely to be major players in the downtown retail market due to their uncertain future and the proximity of major shopping centers in Auburn and Federal Way.

On the other hand, brick-and-mortar retail has proven more resilient than expected in some sectors. Smaller stores that provide immediate access to products, specialty items, and contribute to a sense of community seem to be defying post-pandemic trends, with 2022 on track to be the first year of net-positive store openings since 2016, according to a recent study by Cushman & Wakefield.[7] **Most notably, the food and beverage industry has seen rapid growth as people returned to socializing following pandemic lockdowns, and this trend seems likely to continue.** Figure 6-16 shows the relatively more rapid growth in food and beverage sales compared with all retail sales over the past decade, and particularly since 2020.

[7] Scardina, Barrie. "Making an Impact in Retail: Why Brick & Mortar is Here to Stay." Cushman & Wakefiled, June 16, 2022. https://www.cushmanwakefield.com/en/united-states/insights/us-articles/making-an-impact-in-retail-why-brick-and-mortar-is-here-to-stay

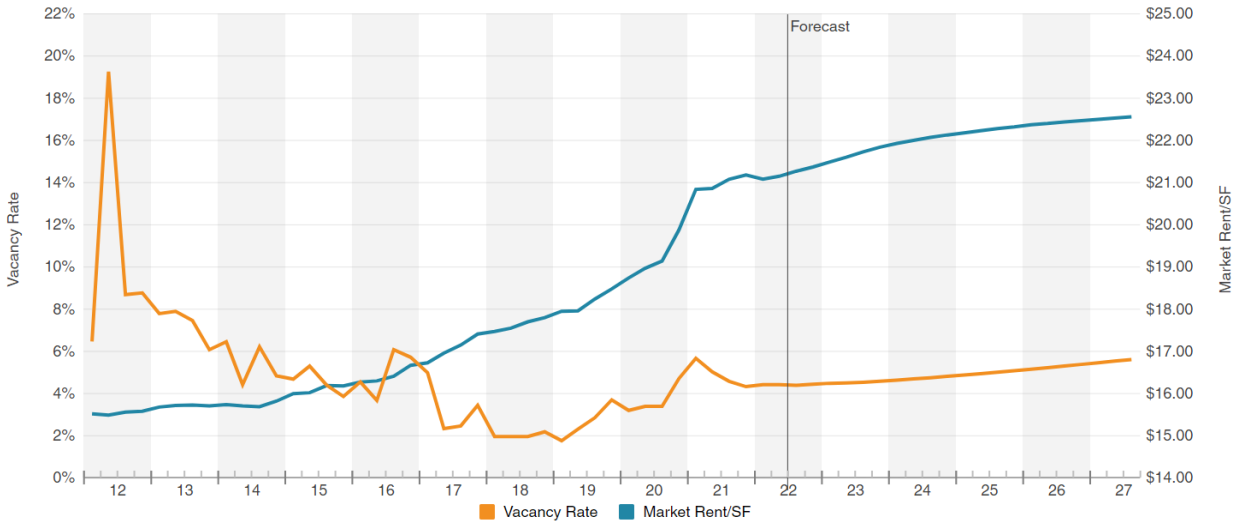
FIGURE 6-16 Indexed Growth in All Retail and Food and Beverage Sales, 2012-2022.



Source: FRED Economic Data, St. Louis FED, US Census Bureau

In addition to these considerations about types of retail, the retail market differs from the multifamily and office market in that new standalone retail is extremely unlikely to be built in the next two decades. Instead, **new retail uses will occupy existing space in historic buildings, new ground floor space in mixed-use developments, and adaptive reuse projects. Downtown Auburn is well positioned in this regard,** with its existing historic Main Street and recent and forthcoming mixed-use projects with ground floor retail space. However, downtown Auburn is currently experiencing many vacant retail storefronts for a variety of reasons. Stakeholders interviewed by the project team in August 2022 expressed frustration that the high rents in the downtown area are out of reach for many small businesses. CoStar data shown in Figure 6-17 confirms that rents have increased significantly over the past two years, as well as vacancy rates. Currently rents are at $12 per square foot and vacancy just above 4 percent.

FIGURE 6-17 Retail Vacancy Rate and Market Rent in Downtown Study Area, 2012-2027 (forecast)



Source: Costar

The vacant storefronts discussed by stakeholders in downtown Auburn are contributing to a sense that little is happening in the area and reports of crime are also of concern to residents and business owners. **Various incentives or programs may be appropriate** to help reduce the vacancies downtown and help catalyze more activity in the area. For example, San Francisco has recently instituted a **Commercial Vacancy Tax** which landlords must pay within certain commercial districts if their commercial properties are vacant for more than 182 days in a caldendar year, to encourage landlords to keep their properties leased.[8]

Auburn has an existing **Business Improvement Area (BIA)** which funds the Downtown Auburn Cooperative and downtown events. The funding structure has recently been updated to receive funding directly from the city rather than from a tax on downtown businesses. Continuing to fund the BIA is an important onging effort in revitalizing the downtown. Among other programs the BIA administers the **Downtown Façade Improvement Grant Program**, which seeks to "preserve and enhance the charm of our Downtown commercial area through strategic physical improvements to buildings." In LCG's view, such programs are definitely a best practice for downtown revitalization, as they can help to nudge property owners to explore more creative uses for their properties that enable more vibrant businesses, attract more shoppers and dinners, and set examples for other nearby property owners. The program could be strengthened by removing the restrictions on businesses with more than 25 employees and on newly constructed buildings to expand its reach.

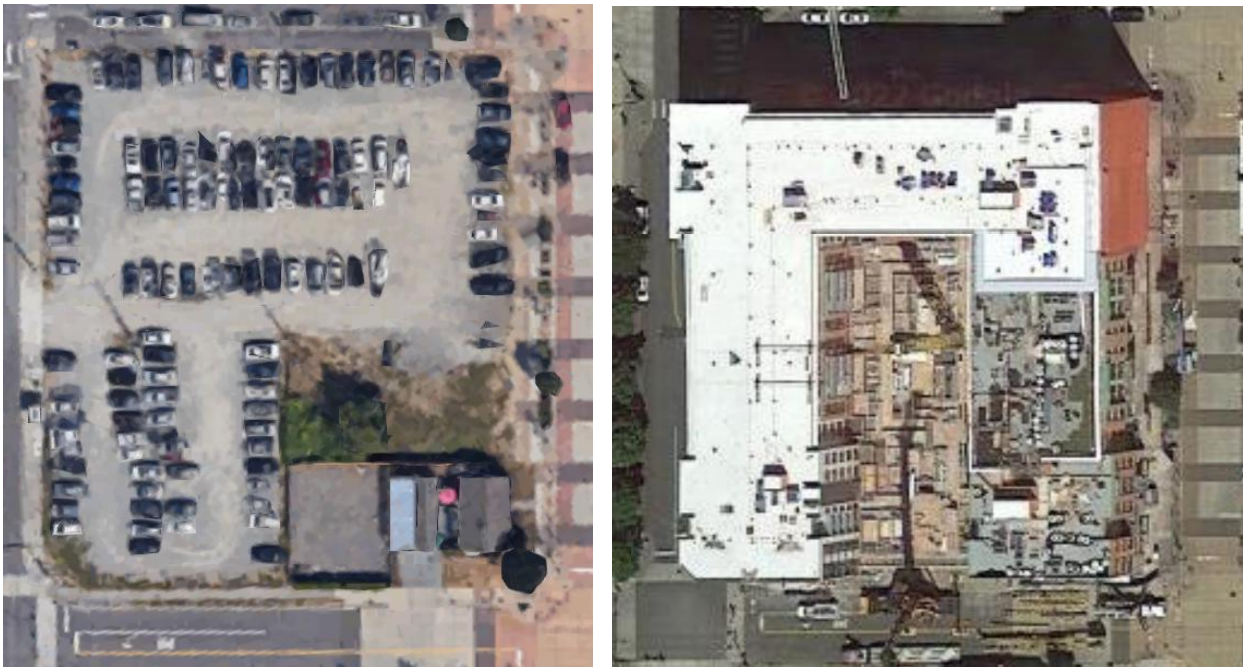
[8] San Francisco Treasurer & Tax Collector. "Commercial Vacancy Tax." https://sftreasurer.org/business/taxes-fees/commercial-vacancy-tax-vt

6.2 Development Areas

Figure 6-19 shows the relationship between the building (improvement) value and the land value in the downtown Auburn study area. This ratio can help to identify sites that are likely to redevelop, if the value of the land is substantially more than the value of the building (i.e., a ratio below 1.0, shown here in brown). Sites with ratios above 1.0 are less likely to redevelop due to the value of the building.

The map below shows **potential movement of development activity towards two areas with clusters of underutilized parcels**. In the Downtown Core, there are several blocks directly to the east of the most recent developments which are showing a low improvement-to-land value ratio. This area currently contains a Safeway and an auto parts store, both surrounded by a significant amount of surface parking. Of note, several recent projects in Auburn including Legacy Plaza and The Verge were developed on similar sites previously occupied by surface parking, as shown below.

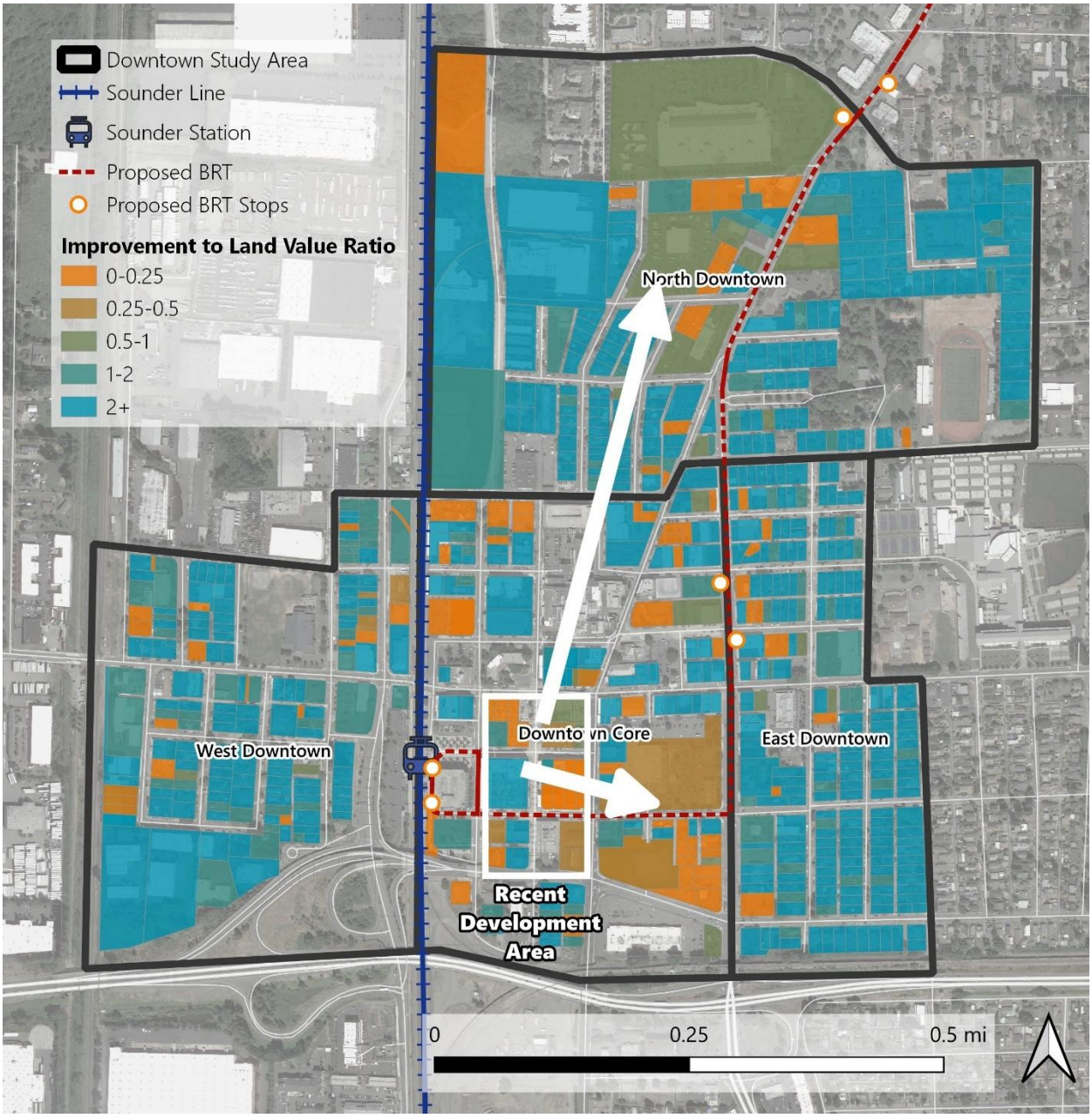
FIGURE 6-18 The Verge Apartments Before and After Development



Source: Google Earth

In the northern area, there is also a **cluster of large, underutilized sites south of Fred Meyer**. These may be potential candidates for redevelopment, particularly in light of the forthcoming King County Rapid Ride 1 line slated to begin service in 2025, with a stop directly adjacent to the Fred Meyer as shown below.

FIGURE 6-19 Improvement to Land Value Ratio in Study Area



Source: City of Auburn GIS, Leland Consulting Group

6.3 Key Findings and Implications for Plan

Market Outlook

- Nationally, developers are shifting away from building hospitality, office, and retail properties in favor of industrial, single family, and multifamily housing.
- Most recent development in downtown Auburn has taken place within a small part of the downtown core, and the majority of the development has been housing over some ground floor commercial space.
- Although the average asking monthly apartment rent in Auburn is among the lowest in the Seattle area, rents have increased by 7.3 percent over the past year, decreasing the gap between Auburn and Seattle metro area rents.
- Multifamily units make up by far the largest amount of square footage in the downtown.
- Auburn as seen considerably more office development than other South Sound municipalities in recent decades, anchored in health care and the public sector.
- Although information and technology jobs are growing the fastest, driven by Seattle's dominance in tech industries, health care and government are both expected to add significant numbers of jobs in the coming years regionally. Auburn's existing cluster of medical facilities makes the downtown well positioned to take advantage of this regional trend.
- Most new retail uses will likely occupy existing space in historic buildings, new ground floor space in mixed-use developments, and adaptive reuse projects. Most notably, the food and beverage industry has seen rapid growth as people returned to socializing following pandemic lockdowns, and this trend seems likely to continue.
- Various incentives or programs may be appropriate to help reduce retail vacancies downtown and help catalyze more activity in the area, such as a commercial vacancy tax, and continued funding for the Business Improvement Association. One key tool is the city's Downtown Façade Improvement Grant Program, which should continue into the future and potentially be provided with more funding in order to be applied to a wider range of buildings and projects. One focus area of this tool should be Historic Main Street.
- Opportunity locations for redevelopment in the downtown include several blocks in the downtown core east of the most recent developments and a cluster of underutilized sites in the north subarea south of Fred Meyer, near the forthcoming BRT line.

SECTION 7 TRANSPORTATION

The Auburn Downtown Plan and Environmental Impact Statement (EIS) was prepared for the City of Auburn in May 2001. Since then, the City has updated its comprehensive plan and policies guiding levels of service for transportation. The transportation context of Auburn has also evolved, following both local and regional infrastructure investments, as well as local and regional growth. This chapter is updated to reflect the current conditions in the city and, consistent with the Comprehensive Plan, newly updated to address a more recent base year of 2022 and horizon year of 2044 and relies on the Comprehensive Plan transportation element update which will summarize 2022 traffic counts.

This chapter begins with summaries of recent plans, programs, and studies related to the City of Auburn Downtown Subarea. Current conditions of the transportation network in the City of Auburn Downtown Subarea are also documented. This includes the traffic operations as of the 2022 Comprehensive Plan update.

7.0 Existing Transportation Plans and Studies

This section provides summaries of recent plans, programs, and studies related to the City of Auburn Downtown Subarea. These summaries help provide a background understanding of the prior transportation planning and regulatory framework in the study area. Plans and studies are organized into (1) Subarea plan, (2) project specific plans, and (3) areawide transportation plans. These are presented in chronological order with most recent plans first.

Area Plans

AUBURN DOWNTOWN PLAN & EIS (2001)

The Auburn Downtown Plan was adopted in May 2001. The goal of the plan was to strengthen the downtown community, economy, and image by building on existing assets, facilitate catalyst projects in key locations, stimulate infill and redevelopment, and influence the design and construction of high-quality public infrastructure. The vision of the downtown plan included key features to enhance transit accessibility, such as clearly identified wayfinding opportunities and maintaining historic railroad design.

The Plan identified the transit center as a key hub to providing connections to Main Street and the core retail area. Also identified were challenges to mobility in the downtown area, including a need for enhanced mobility connections between downtown districts, as well as development of

underutilized properties. A well-designed and defined pedestrian environment is also not present off of Main Street due to the presence of heavy commercial, industrial, and auto-oriented uses. The Plan also acknowledges the challenges that heavy freight traffic places on the walkability and desirability of Downtown Auburn.

COMPREHENSIVE DOWNTOWN PARKING MANAGEMENT PLAN (2014)

The Comprehensive Downtown Parking Management Plan (CDPMP) manages existing parking assets, assesses current parking demand, forecasts future parking needs, and endeavors to develop a first-rate downtown parking system. The CDPMP was adopted in January 2014.

As of the 2014 Plan, there were no considerations to expand the on- and off-street parking supply in the Downtown Urban Center. However, the Auburn Transit Center is planned through Sound Transit to construct a second garage. In 2022, Sound Transit hosted virtual engagement opportunities to determine the location of the garage. This construction project is estimated to complete in 2026.

Project Specific Plans

AUBURN STATION PARKING AND ACCESS IMPROVEMENTS

Sound Transit is improving access to the Auburn Sounder Station for riders, whether they access the station by walking, bicycling, connecting buses or driving. This project includes a new parking garage located at 1st Street Northwest and is expected to complete by 2026.

This parking garage will add parking as the existing Auburn Station parking garage is filled to capacity during the morning commute for riders using the Sounder S Line train travelling between Lakewood and downtown Seattle. This train completes 13 roundtrips each weekday and runs special service for select events. Construction is expected to start as early as late 2023 with opening to the public in late 2026.

Local Jurisdiction and Agency Plans

CITY OF AUBURN

Auburn Comprehensive Plan – Transportation Element (2015)

The Auburn Comprehensive Plan was adopted in 2015 and recently updated in December 2021. The Plan describes existing transportation conditions and future changes and needs as they relate to growth in the City. December 2021 updates included changes to the existing transportation network, an updated current needs evaluation, and identification of standards for future development and infrastructure improvement scenarios.

The Comprehensive Plan details anticipated land use development patterns and transportation capital needs citywide through 2044. The Comprehensive Plan identifies the following major transportation investments in Downtown:

Auburn Way Corridor Improvements	Construct pedestrian accessibility and aesthetic enhancements on Auburn Way between 4th St NE and 4th St SE, including curb-bulbs at intersections adjacent to on-street parking, a new northbound left-turn at 3rd St SE, and signal and channelization improvements at E Main St.
Main Street TOD Infrastructure Improvements – Western Main Street	West Main Street, B Street NW/SW to Division Street, replace roadway, parking, sidewalks, and utilities.
Main Street TOD Infrastructure Improvements – Central Main Street	East Main Street, Auburn Avenue to Auburn Way North – replace roadway, parking, sidewalks, and utilities.
Main Street TOD Infrastructure Improvements – Eastern Main Street	East Main Street, Auburn Way to F Street SE/NE, replace roadway, parking, sidewalks, and utilities.

Puget Sound Vision 2050 (2021)

The City of Auburn downtown subarea is identified in the Puget Sound Regional Council Vision 2050 plan as a Regional Growth Center (RGC) intended to accommodate a significant share of future growth. To achieve regional growth goals, Auburn should encourage development near high-capacity transit stations and within regional growth centers.

2022 – 2027 Transportation Improvement Program (2021)

The Transportation Improvement Program (TIP) was adopted in June 2021 and sets priorities for the allocation of secured and unsecured funding and coordinates future transportation projects with needed utility improvements. Projects in the TIP that fall within the Downtown Subarea study boundary are included below:

- Auburn Way N/1st St NE – Signal Replacement
- Auburn Avenue/E Main Street – Signal Replacement

- A Street NW Phases 1 & 2
- 2nd Street SE Preservation

City of Auburn Local Road Safety Plan (2022)

The Local Road Safety Plan (LRSP) was adopted in March 2022 and summarizes a systemic safety analysis of Auburn's citywide transportation network. The Plan found that factors such as high-speed roadways (with posted speeds greater than 35 miles per hour), widely spaced street lighting, the presence of industrial land uses, streets with higher functional classifications, and alcohol/drug use are all contributing factors to the most to serious or fatal collisions in Auburn. Within the Downtown Study Area, Auburn Way was found to have the highest collision risk factors for serious or fatal collisions.

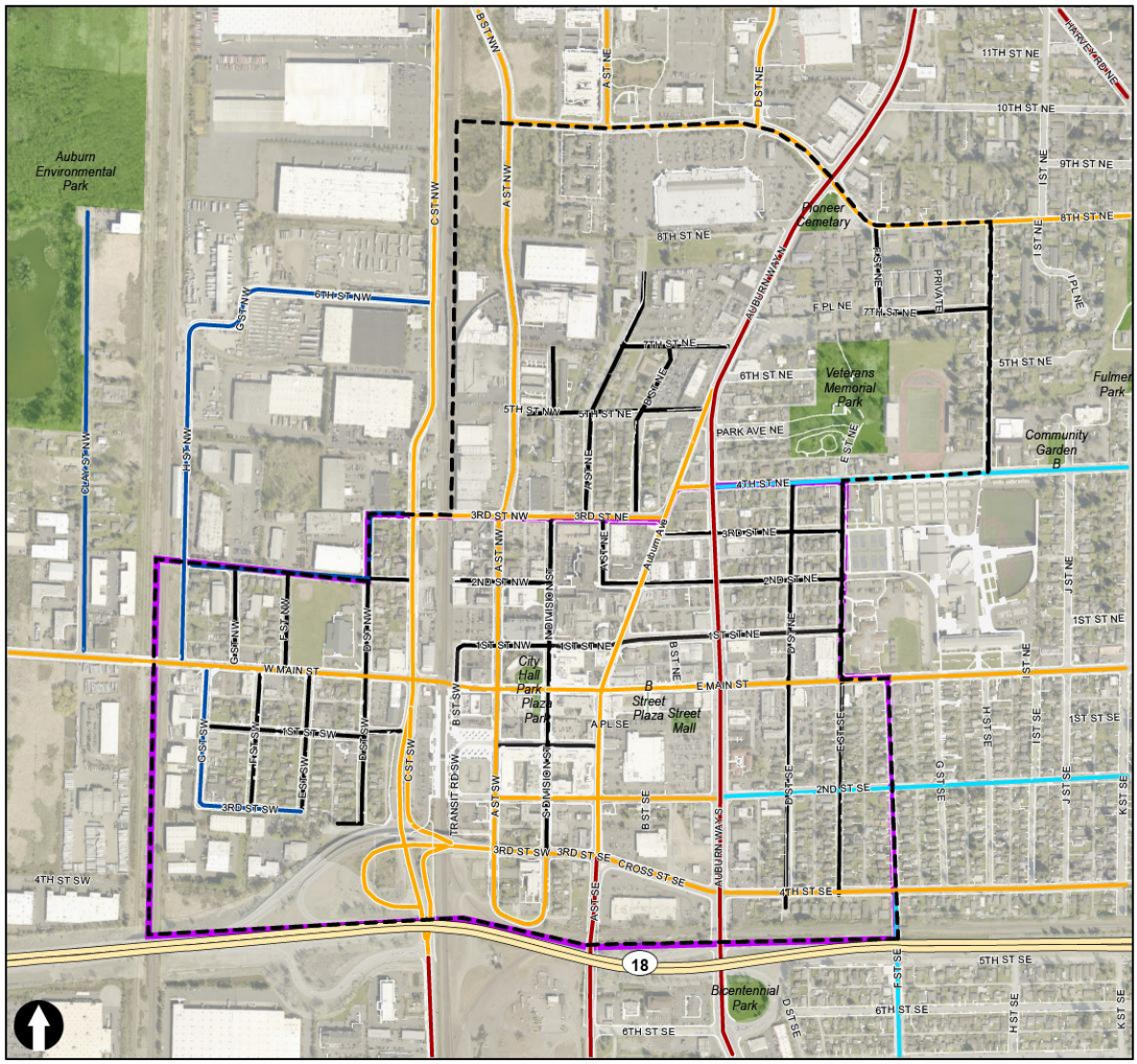
7.1 Current Conditions

This section provides summaries of the existing transportation network in the City of Auburn Downtown Area. These summaries help provide a background understanding of the existing transportation conditions to provide a framework from which to build off for the future conditions analysis.

Roadway Network

The street system functions as a network. Functional classification is the hierarchy by which streets and highways are defined according to the character of service they provide. The three main classes of streets in Auburn are arterials, collectors, and local streets. Existing street classifications are shown in Figure 1, with unidentified streets classified as local streets. Understanding the existing functional classification helps establish which corridors will provide for the future movement of people and goods, as well as emergency vehicle access. As development is being considered, accommodation for the appropriate transportation corridors is crucial. In the downtown study area, most streets are primarily collector and local roadways, with three arterials running north-south and one east-west connection.

FIGURE 7-1 Roadway Network



2024 Roadway Classification

- Principal Arterial
- Minor Arterial
- Collector
- Industrial Collector
- Local (Not show on map out side of study area)
- Study Area
- Current Downtown / RGC
- SR-18
- Parks

Source: MAKERS, City of Auburn 2024 Roadway Classifications

TRAFFIC OPERATIONS

As of the 2021 comprehensive plan, the City uses a single-mode LOS system based upon vehicular travel. Corridor segments within Downtown Auburn may operate at LOS E. All other arterial and collector corridors in the City must operate at LOS D or better, unless otherwise indicated. The City also uses a weekday PM peak hour unless there are unique conditions present.

TABLE 7-1 shows the levels-of-service results for the downtown study area intersections for the existing 2022 AM and PM peak hours.

TABLE 7-1 **Intersection Level of Service – Existing 2022 AM/PM Peak Hour**

ID	Name	Control Type	HCM Edition	AM LOS / Delay (S)	PM LOS / Delay (s)
339	B St NE/B St NE & 10th St NE	TWSC	6th	B / 14	C / 18
61*	AWN & 1st St NE	Signal	6th	A / 9	B / 13
60	AWN & 4th St NE	Signal	2000	C / 25	B / 19
34	AWN & 9th St NE/8th St NE	Signal	6th	C / 20	C / 25
62	AWS/AWN & E Main St	Signal	2000	C / 27	C / 32
63*	AWS & 2nd St SE	Signal	2000	A / 8	B / 11
80*	AWS & Cross St SE/4th St SE	Signal	6th	B / 12	B / 13
81	AWS & SR-18 WB On/SR-18 WB Off	Signal	6th	B / 19	C / 30
35	10th St NE/9th St NE & D St NE	Signal	6th	B / 12	B / 20
64*	F St SE & 4th St SE	Signal	6th	B / 15	B / 15
114	C St SW & 3rd St NW	Signal	6th	A / 8	F / 90
115	A St NE & 3rd St NE/3rd St NE	Signal	2000	C / 25	C / 25
71	Auburn Ave & 3rd St NE	Signal	2000	A / 8	B / 14
70	Auburn Ave & 4th St NE	Signal	2000	A / 4	A / 4
72	Auburn Ave & 1st St NE	Signal	6th	A / 4	A / 9
110	S Division/N Division & West Main St/East Main St	Signal	6th	A / 6	A / 7
111	A St SW/A St NW & West Main St	Signal	6th	A / 9	B / 10
113	C St SW & West Main St	Signal	6th	C / 22	C / 22
74*	A St SE & 2nd St SE	Signal	6th	B / 16	C / 30
75	A St SE & 3rd St SE/Cross St SE	Signal	6th	C / 27	D / 37
76	S Division & 3rd St SW/3rd St SE	Signal	6th	B / 12	B / 15
484	C St SW & SR18 WB ON/OFF	Signal	6th	B / 13	B / 19
312	C St SW & SR18 EB ON/OFF	Signal	2000	B / 14	B / 15
439	10th St NE & A St NE	AWSC	6th	A / 8	B / 11
518	A St SW & Transit Driveway/1st St SW	AWSC	6th	A / 8	A / 8
112	A St SW & 2nd St SW	Signal	6th	B / 14	B / 13
521	F St SE & 2nd St SE	AWSC	6th	A / 8	A / 8

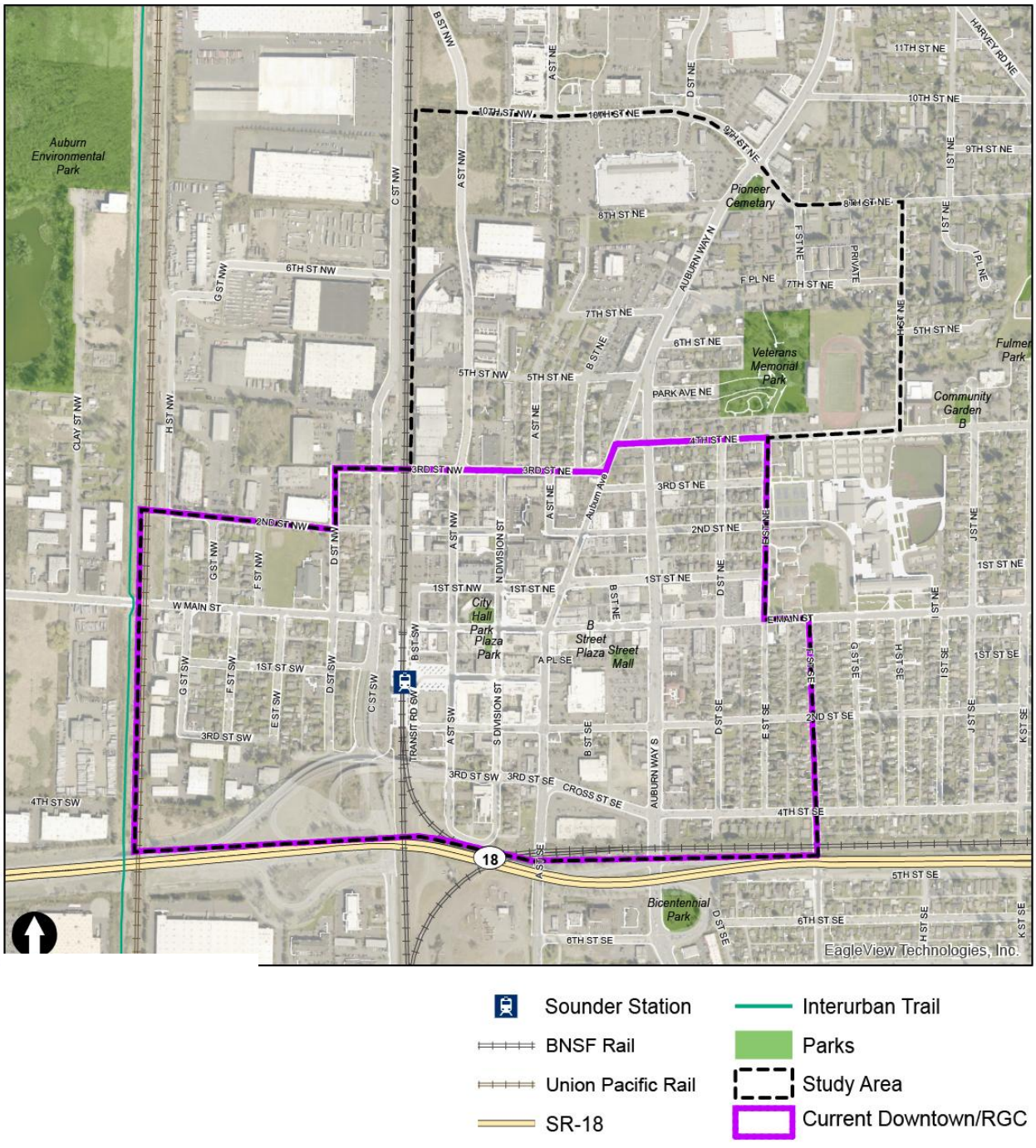
*LOS results for intersections are not from 2022 traffic counts.

As of 2022, all of the intersections operate at LOS D or better except for intersection 114 (C St SW & 3rd St NW), which operates at LOS F in the PM peak period. As part of the City's 2024 Comprehensive Plan update, the City plans to adopt more multi-modal level of service standards, which consider conditions for people walking, biking, and using transit.

Rail

The Union Pacific Railroad (UP) and Burlington Northern Santa Fe Railway (BNSF) have rail lines running through Auburn as indicated in Figure 2. The UP Railroad runs north-south along the western edge of the study area boundary. BNSF also runs north-south, has a double-track, and operates the rail yard between A Street SE and C Street SW, south of SR-18. This area may develop as a multi-modal rail yard in the future, which could necessitate capacity improvements due to increased truck traffic. While the rail yard is outside the study area, future development could impact traffic flow through downtown. Finally, the Sounder additionally runs through downtown Auburn on BNSF tracks, with the Sounder station located downtown with one parking garage and a second parking garage undergoing planning development with a tentative completion date of 2024.

FIGURE 7-2 Rail Network

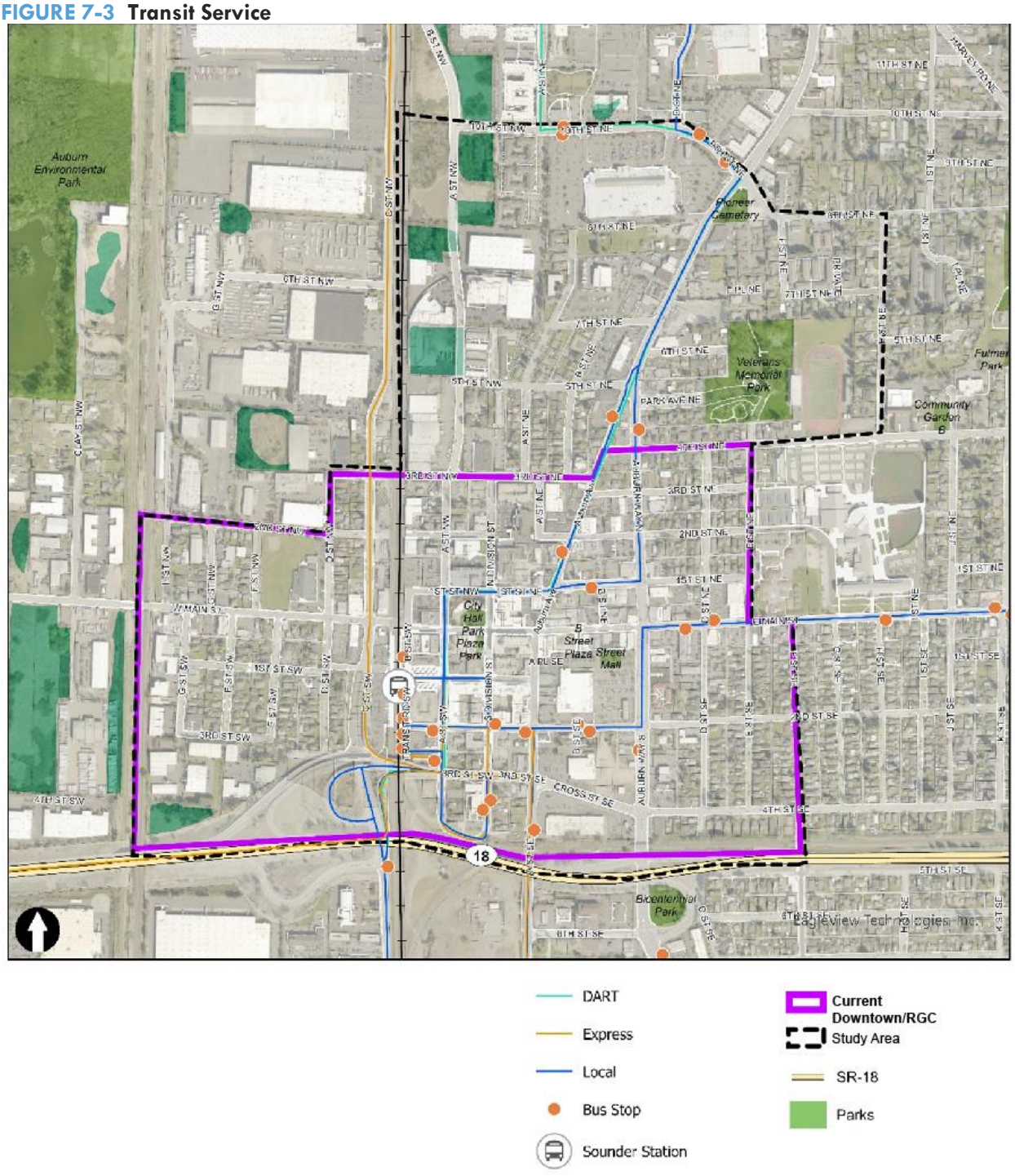


Fehr & Peers, City of Auburn GIS data

Transit

The City of Auburn does not administer transit service. The City coordinates service with King County Metro Transit, Pierce Transit, Sound Transit, and Muckleshoot Tribal (MIT) transit. Transit in the city operates at local service (30-minute headways in the peak period) and frequent/express service (less than 30 minute headways in the peak period). Service is also offered through DART (Dial-A-Ride Transit) which arranges transit service on demand. As noted above, the City of Auburn has a rail station, which is served by Sound Transit's Sounder train, which runs primarily during peak AM/PM weekday hours. Figure 3 represents the existing transit network.

FIGURE 7-3 Transit Service



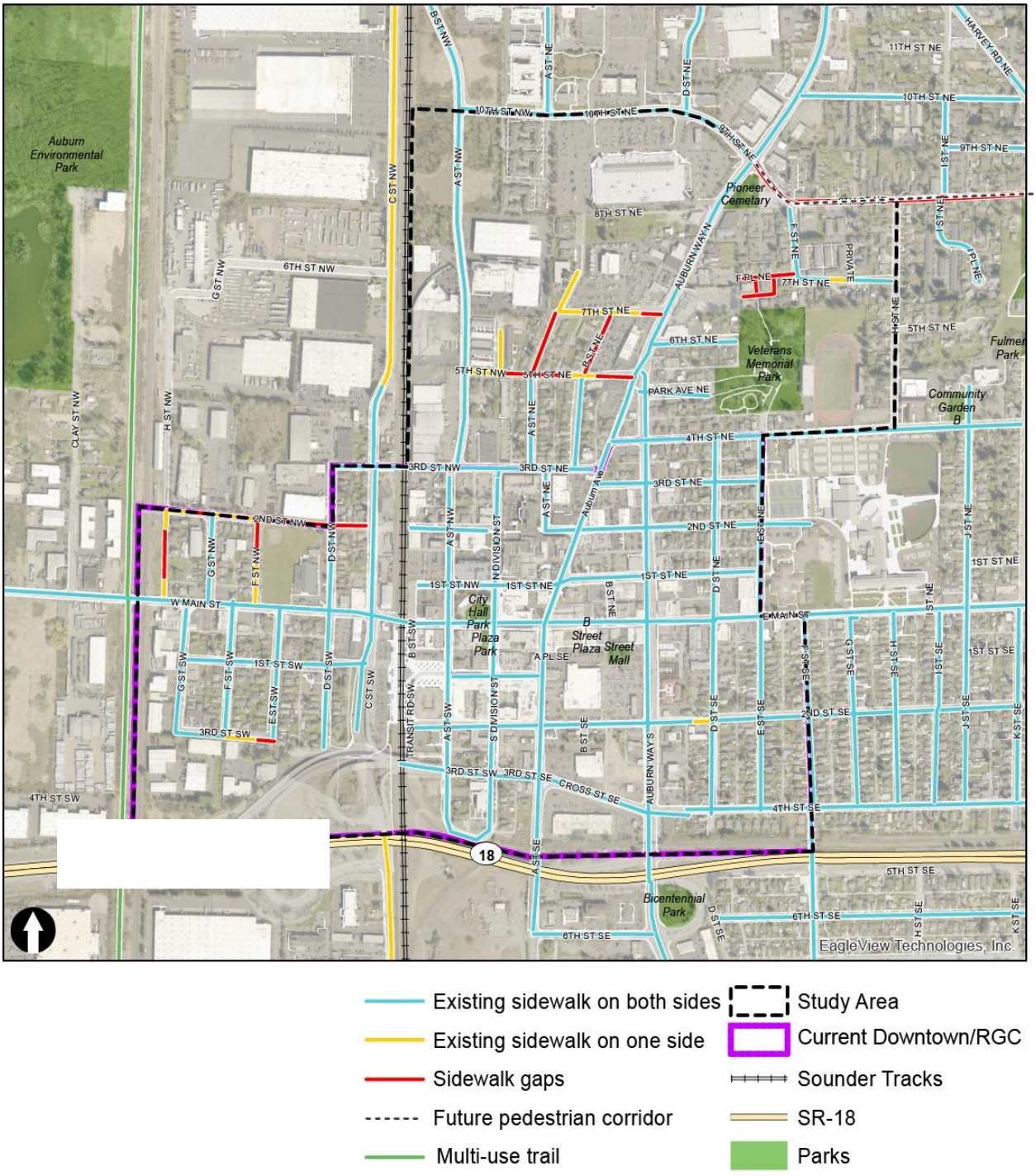
Fehr & Peers, City of Auburn GIS data

Active Transportation

PEDESTRIAN NETWORK

Downtown Auburn offers a complete pedestrian network, in which sidewalks are generally available on both sides of most streets and there are also two multiuse trails in proximity to the study area. Overall, this supports a positive pedestrian environment, as businesses, shops, and single-family homes in the downtown core generally benefit from sidewalks and street trees. However, sidewalks tend to be in varying conditions, with some of the older sections of the study area in need of sidewalk repairs or replacement, and some sidewalks too narrow to provide comfortable walkability.

FIGURE 7-4 Pedestrian Network

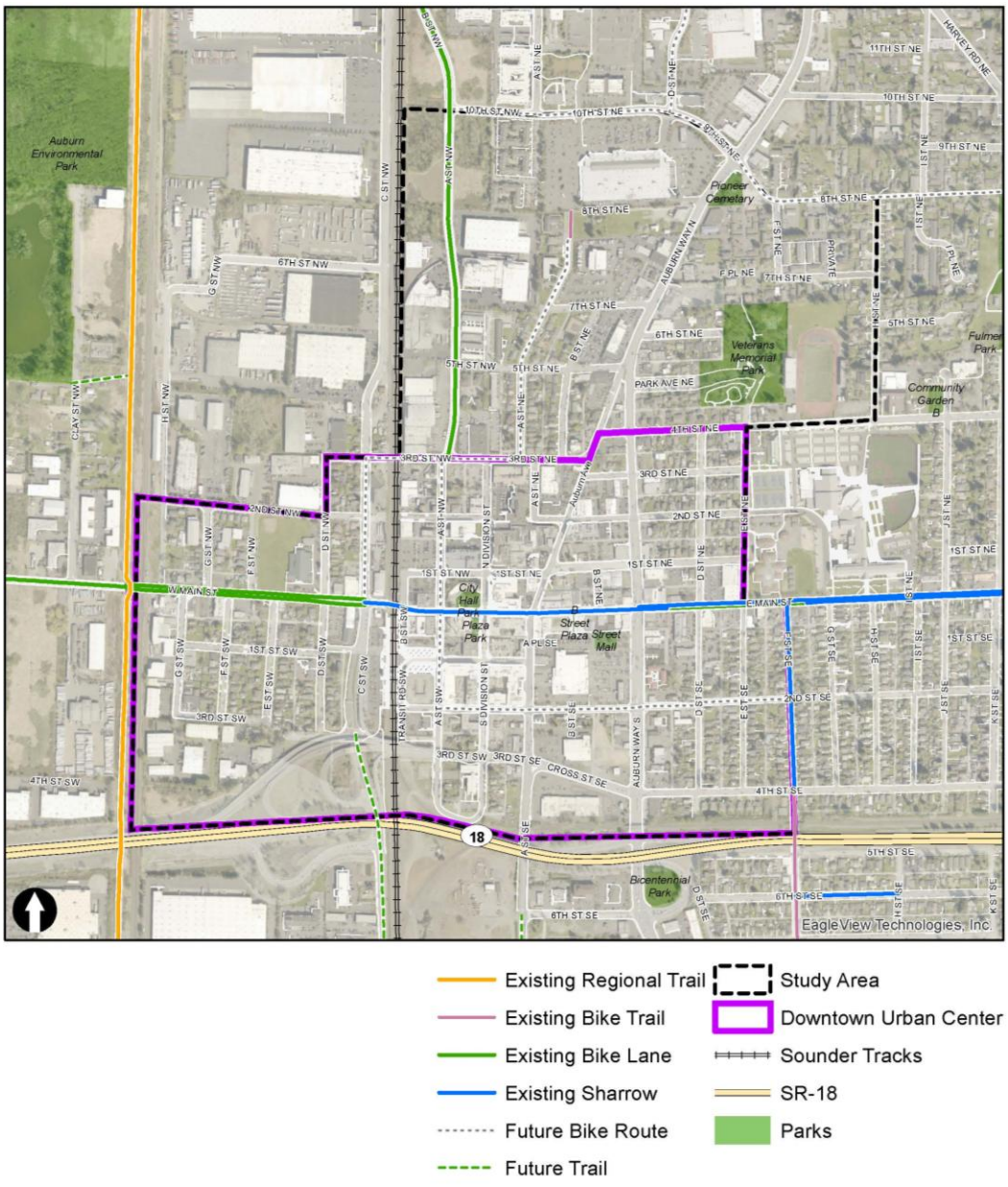


Source: Fehr & Peers and MAKERS, City of Auburn GIS data

BICYCLE NETWORK

Better accommodating people who wish to travel by bike is priority for the City. Current infrastructure benefits from access to regional trails such as the Interurban Trail directly west of downtown. However, there are few existing bicycle facilities in the City, with only existing sharrows and bike lanes in the study area. There are also two multiuse trails in proximity to the study area as seen in
Figure 7-5

FIGURE 7-5 Bicycle Network

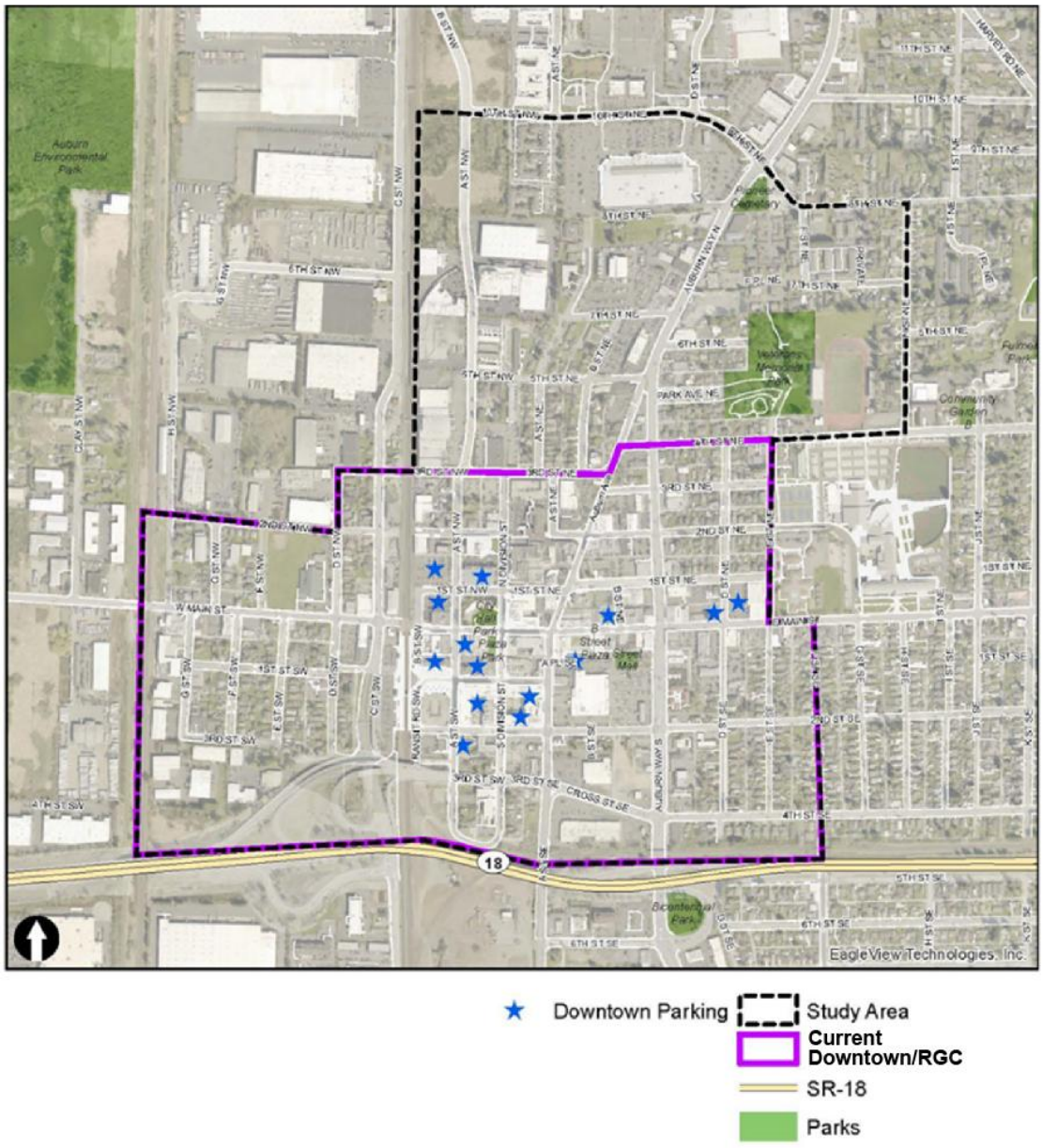


Source: Fehr & Peers, City of Auburn GIS data

Parking

According to the Comprehensive Downtown Parking Management Plan (CDPMP), adopted January 2014, there were a total of 4,879 parking spaces in the Downtown Urban Center (DUC) as of December 2011. This includes on-street public parking, off-street public parking, and off-street private parking. Figure 7-6 shows the locations of parking lots downtown. Other parking is included on-street with time limits.

FIGURE 7-6 Parking

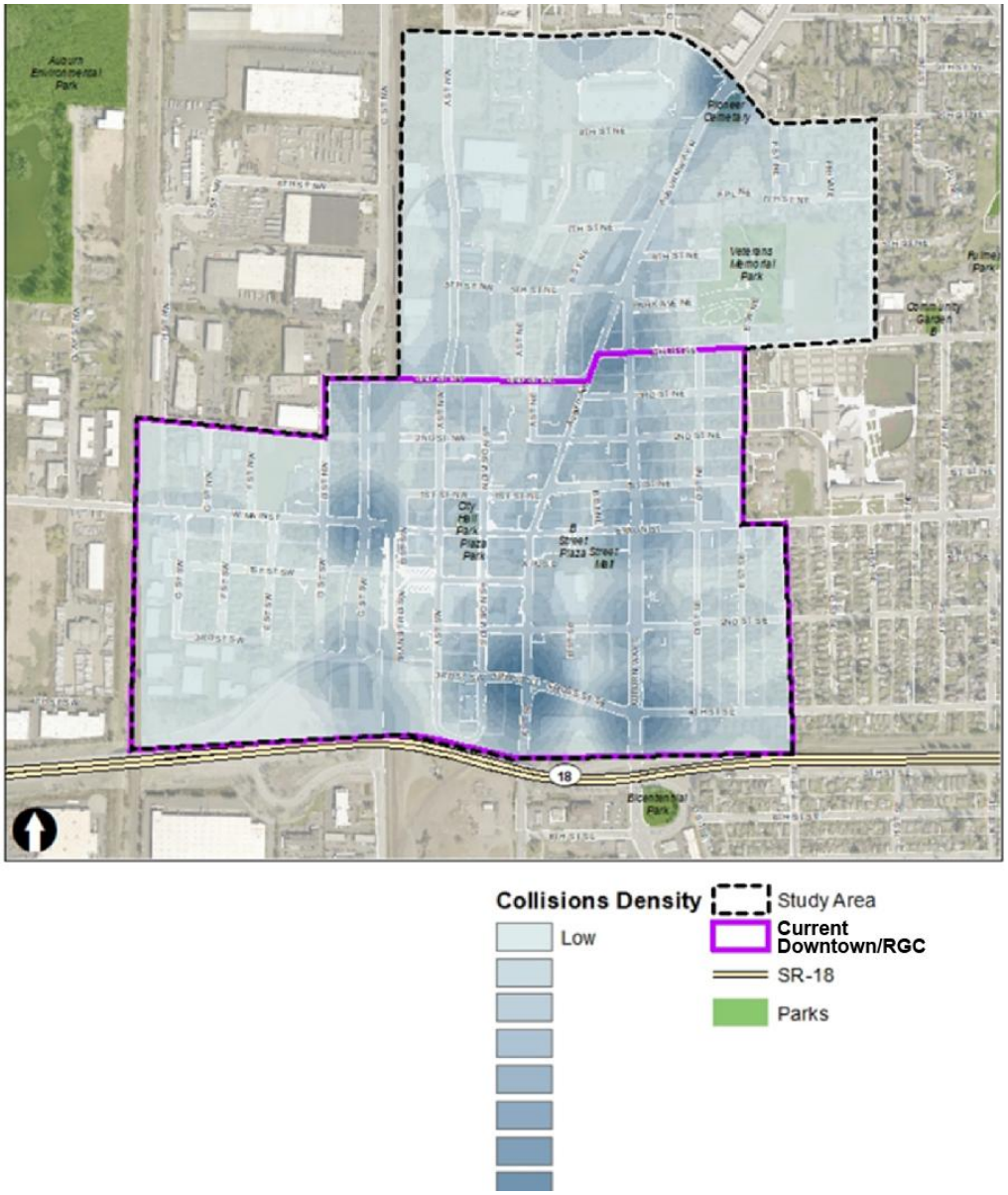


Source: Fehr & Peers, City of Auburn GIS data

Safety

Safety is a high priority for the City to promote a downtown environment that accommodates multiple transportation modes. The City's comprehensive plan policies include a goal to "significantly reduce or eliminate traffic fatalities and serious injuries through a safe systems approach." Figure 7-7 shows the locations in Downtown with the highest density of collisions. As shown by the heatmap, most collisions occurred along principal and minor arterial roadways, as well as major intersections. At grade rail crossing intersections are also evaluated for safety, including several in the downtown study area. There have been recent upgrades to the rail crossings, such as pre-signals that prevent vehicles from stopping on the crossing.

FIGURE 7-7 Safety



Source: Fehr & Peers

7.2 Key Findings and Implications for Plan

- As the City of Auburn updates the Comprehensive Plan to reflect a 2044 future year, the Downtown subarea will receive subsequent updates. There are several projects in and around the downtown subarea, such as the Sound Transit construction of a new parking garage to accommodate demand around the Sounder rail line. Additionally, plans in the vicinity of the downtown subarea will impact traffic needs in and around the study area.

- The downtown subarea has adequate sidewalk presence, but sidewalks are varying in quality and conditions. There is limited separated bicycle infrastructure in the city, but the downtown area is in proximity to regional trails. There are also principal and minor arterials and freight rail lines running through the study area boundary, which emphasizes the need to ensure safe and accessible facilities for all modes. From a safety perspective, the Local Road Safety Plan found that collisions primarily occur along principal and minor arterial roadways at major intersections.
- The City does not administer transit service. Transit service is provided through Sound Transit, King County Metro Transit, Pierce Transit, and Muckleshoot Tribal (MIT) Transit. The City also has Sounder rail service, with one north/south rail line that provides service for both the Sounder and BNSF. Finally, parking is offered through on-street public parking, off-street public parking, and off-street private parking.
- Currently, all intersections that fall within the downtown study area boundary operate at a Level of Service D or better, with the exception of one intersection (C St SW & 3rd St NW) operating at LOS F in the PM peak.

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SECTION 8 PUBLIC SERVICES

This section documents existing facilities for public schools, police services, fire/emergency medical response, and parks and recreation facilities serving the study area. Future needs for services that serve an area larger than Downtown will be addressed by the City's Comprehensive Plan update, which will be completed in 2024.

8.0 Schools

Current Conditions

There are three schools in or adjacent to the study area:

- West Auburn Senor High School
- Washington Elementary School (adjacent to the study area)
- Auburn High School (Adjacent to the study area)

These schools serve an area larger than the Downtown Plan study area. Future needs will be addressed through the City's upcoming Comprehensive Plan update.

8.1 Police

Current Conditions

The Auburn Police Department headquarters is currently located in Downtown Auburn at the Auburn Justice Center at 340 East Main Street. However, the City is planning to move this facility outside of downtown by 2044.

8.2 Fire

The Valley Regional Fire Authority (VRFA) provide fire and emergency life safety services to Auburn, as well as the Algona and Pacific Communities.

Current Conditions

The VRFA operates the following facilities in Auburn.

TABLE 8-1 VRFA Facilities Located within Auburn

Facility	Location	Description

Fire Station 31 – VRFA Headquarters	1101 D ST NE, Auburn WA 98002	The VFRA Station 32 is a 9,000 sf facility that handled 44 % of the total emergency calls in 2019, the busiest station in the system. The station was was remodeled in 2010 and the 2021-2017 Captial Facilities Plan indicates that the building and location are in good condition. This station's response zone includes Downtown Auburn.
Fire Station 32 – South Auburn	1951 R Street SE, Auburn WA 98002	This is a 9,000 sf facility that was built in 1985 and rennovated in 2010. The 2021-2017 Captial Facilities Plan indicates that the building and location are in good condition. It handled 28.12% of all calls in 2019 and is located approximately 2.25 miles southeast of Downtown Auburn.
Fire Station 34 – Lea Hill	31290 124th AVE SE, Auburn WA 98092	This station was built in 2011 and is a total of 11,000 SF. and the 2021-2017 Captial Facilities Plan indicates that the building is in excellent condition and the site is well-positions. It is approximately 2.5 miles northeast of Downtown Auburn. The station handled 6.7% of total calls in 2019.
Fire Station 35 – Support Services / Fire Marshal's Office	2905 C Street SW, Auburn WA 98002	Station 25 is 20,000 sf and houses the Fire Marshal's Office, Support Services, Public Information, and Emergency Management divisions. The building was built in 1944 and is utilized on a month-to-month lease. It is at capacity for office space, but is a useful warehouse facility.

Recent Projects, Planned Improvements, and Identified Future Needs

The VRFA 2021-2017 Capital Facilities Plan's top priority recommendation was to add a new station at the North end of Auburn, north of 30th St NE. This would alleviate pressure on station 31, which currently serves Downtown Auburn. The report also recommends remodeling station 31.

8.3 Parks

Parks and Open Space

POLICY FRAMEWORK

2015 Parks and Recreation Open Space Plan

Downtown is one residential area that isn't currently served by a neighborhood park. (The standard for park acres currently in the City of Auburn is 6.03 acres per 1000 residents.) Adding greenspace downtown would align with several goals of the plan.

- **Positive image through parks** – adding more open space downtown is a key objective of this goal. This open space would serve both community need and help stimulate economic growth downtown.

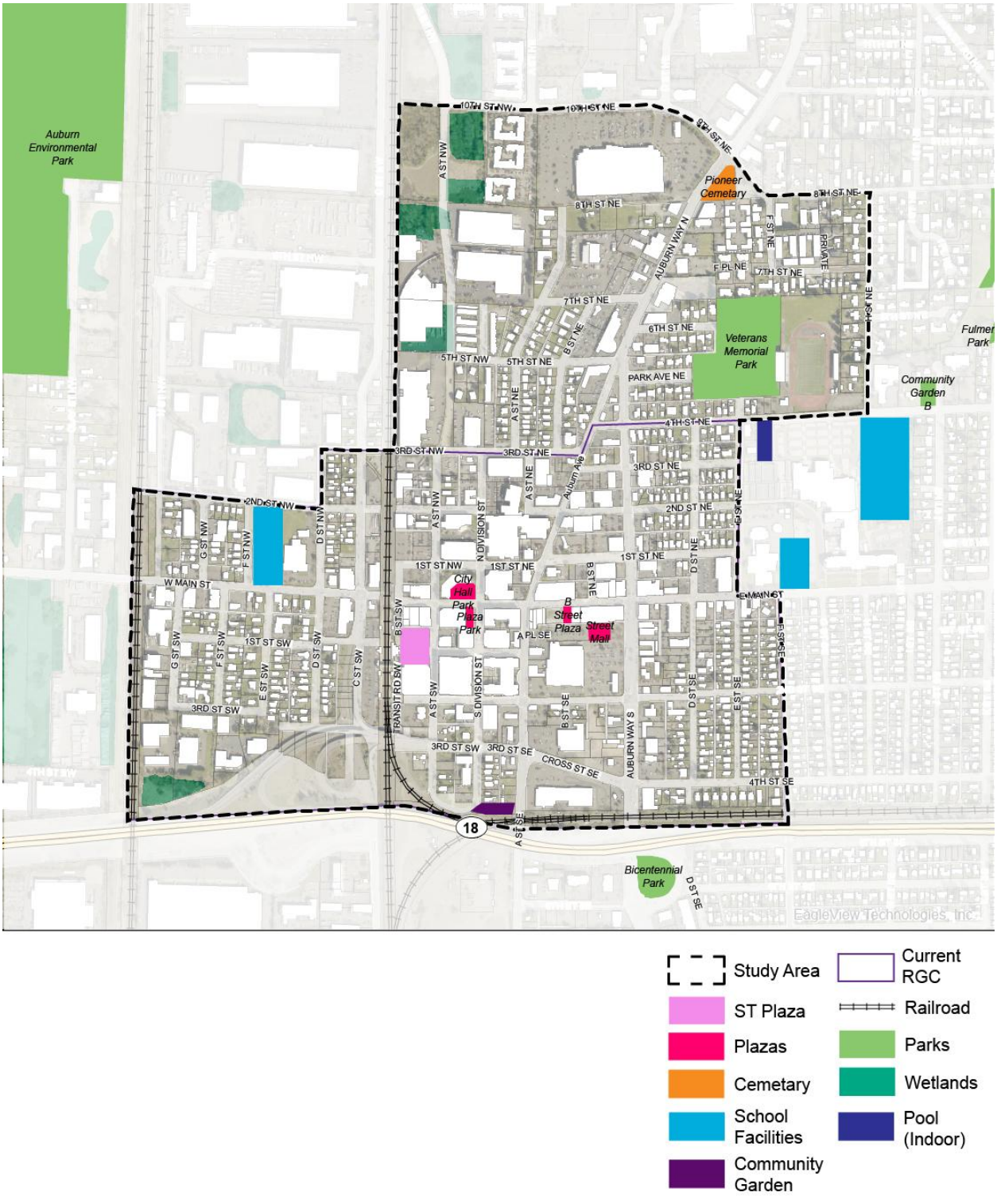
- **New parks** – adding a park downtown supports this goal by helping the city meet the overall level of service standard.

The Auburn Parks and Recreation department also oversees several arts and cultural programs, including the artwork on loan program that places sculptures in public spaces around downtown. There is a strong interest from the community in using arts and culture to continue to raise the profile of downtown Auburn.

CURRENT CONDITIONS

There is very limited green open space within the study area, and near-complete lack of greens space within the current DUC boundary. The area also includes a number of hardscape plaza spaces, which add to the pedestrian-environment of downtown, but do not offer green space or recreation opportunities.

FIGURE 8-1 Map of existing parks and plazas



SOURCES: City of Auburn GIS Data, MAKERS

8.4 Key Findings and Implications for Plan

- There is already a need for new fire station that serves the Downtown area. Further development downtown may increase the need for that public service.
- Parks plans have indicated Downtown as needing more open space, a finding that aligns with Urban Form section.

SECTION 9 UTILITIES AND STORMWATER

The section describes the existing conditions for utilities including water, wastewater, electricity, natural gas, telecommunications utilities, and stormwater within the study area. It includes a discussion of existing policies, plans, and regulations; current conditions; and key findings and implications for the Subarea Plan (the Plan).

9.0 Existing Policies, Plans, and Regulations

Utilities in the study area (water, wastewater, electricity, natural gas, telecommunications, and stormwater) are regulated at the local level and are described below.

9.1 Current Conditions

Water

The City's water sources include the Coal Creek Springs and West Hill Springs watersheds, and are supplemented by a system of ten wells and two connections to the regional water system operated by Tacoma Public Utilities. Storage facilities are found on the Enumclaw plateau, at Lakeland Hills, and at Lea Hill.

Water service in the general downtown area is noted by staff as having existing and future capacity issues, which are being evaluated in an updated Water Services Plan and projects incorporated into the 2044 periodic comprehensive plan.

Wastewater

The study area is served by the Valley Sewer Basin, which the 2015 Comprehensive Plan indicates contains the oldest portions of the City's sewer collection system.

Sewer lines run in alleyways throughout much of the downtown area, which can limit the type and size of development that can occur without moving these facilities.

Electricity and Natural Gas

Puget Sound Energy provides electrical and natural gas service to the City of Auburn.

- PSE builds, operates, and maintains an electrical system consisting of generation, transmission, and distribution facilities.
- Washington state is pushing to reduce carbon emissions by 45% below 1990 levels by 2030, and 95% below 1990 levels by 2050. A shift towards more electrification is one of the major ways the State will meet these targets.

Telecommunications

The 2015 Imagine Auburn Comprehensive Plan indicated the following telecommunications services within the city.

- Conventional local telephone service to the City is provided by CenturyLink and Auburn's central office is located in downtown Auburn, and typically four main lines run from the central office to provide service to the area. Several carriers provide long distance service to the area through a network of underground fiber-optic cables that pass through the City.
- Cellular telephone service within the City, its potential annexation areas, and the Puget Sound region overall is provided by multiple private. Cellular providers are regulated by the Federal Communications Commission. Technology and business practices in the area of telecommunications continue to change rapidly.
- Cable television service is provided by Comcast through a combination of aerial and underground cables.

Stormwater

This chapter describes the existing conditions for stormwater within the City of Auburn Downtown study area. It includes a discussion of existing policies, plans, and regulations; existing stormwater and water quality conditions; and key findings and implications for the Subarea Plan (the Plan). Information contained in this section is based on readily available secondary sources of data; primary research, such as project-specific water quality monitoring or modeling, has not been conducted as part of this analysis.

9.2 Existing Policies and Regulations

Stormwater and water quality in the study area are regulated at the federal, state, tribal, and local levels, as described below. In the discussion below, it is worth noting that some federal environmental regulations and permitting related to stormwater and water quality are administered at the state and local levels.

Federal Regulatory Requirements

The purpose of the federal Clean Water Act (CWA) (33 U.S.C. §1251 et seq.) is to restore and maintain the chemical, physical, and biological integrity of the nation's waters. The CWA establishes the basic structure for regulating pollutant discharges into waters of the U.S, including pollutant discharges from stormwater. Sections of the CWA relevant to stormwater management include the following:

1. Section 303(c) of the CWA directs states to adopt water quality standards.
2. Section 303(d) establishes a process for states to identify and clean up polluted waters not meeting water quality standards.
3. Section 305(b) requires states to submit a report on the water quality status of waters to the U.S. Environmental Protection Agency (EPA) every two years.
4. Section 402 establishes the National Pollutant Discharge Elimination System (NPDES) program, requiring pollutant discharges to surface waters be authorized by a permit. NDPES permit requirements initially applied to point source discharges, but the program was expanded in 1987 to explicitly include stormwater discharges.

State Regulatory Requirements

SURFACE WATER QUALITY STANDARDS

Washington's surface water quality standards are the basis for water quality protection in the state, implementing portions of the federal CWA. Chapter 173-201A of the Washington Administrative Code (WAC) states "*the purpose of this chapter is to establish water quality standards for surface waters of the State of Washington consistent with public health and public enjoyment of the waters and the propagation and protection of fish, shellfish, and wildlife … . All surface waters are protected by numeric and narrative criteria, designated uses, and an antidegradation policy*."

Ecology performs a Water Quality Assessment every two years to assess the status of Washington's waters relative to water quality standards and identify those most in need of cleanup actions. Ecology develops the 303(d) list of polluted waters that require a water improvement project and leads development of Total Maximum Daily Loads (TMDLs) to clean up those waters. Ecology's currently effective Water Quality Assessment and 303(d) list – from 2018 - were approved by EPA on August 26, 2022.

Ecology applies surface water quality standards and incorporates 303(d) listings and TMDL projects into the conditions of its water quality permits, including NPDES stormwater permits. NPDES stormwater permits issued by Ecology are discussed below.

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES)

Ecology administers the NPDES permitting program in Washington on non-federal, non-tribal lands, which covers the Auburn Downtown study area. Ecology has developed general NPDES permits for municipal, construction, and industrial stormwater discharges to surface waters that could apply to future development and operations in the Auburn Downtown study area.

Municipal

Ecology administers the NPDES Western Washington Phase II Municipal Stormwater Permit, which is applicable to regulated small municipal separate storm sewer systems (MS4s) located on the west side of the Cascade Mountains. This permit requires local governments to develop and implement stormwater management programs to control pollutants in discharges from their MS4s and protect water quality in downstream receiving waters. The City of Auburn is a permittee under Ecology's Phase II municipal permit and implements a municipal stormwater program, as described in the *Local Plans, Policies, and Regulations* sub-section below.

Construction

Operators of construction activities that involve clearing, grading, and/or excavation that results in the disturbance of one or more acres, and which discharge stormwater to a surface water of state, are required to apply for coverage under Ecology's NPDES Construction Stormwater General Permit (CSWGP). Compliance with this permit requires development and implementation of a Construction Stormwater Pollution Prevention Plan (SWPPP) to prevent erosion and sedimentation and reduce, eliminate, or prevent contamination and water pollution from construction activity. This permit requires operators to conduct site inspections, perform turbidity/transparency monitoring of discharges, and conduct stormwater pH sampling for significant concrete work or use of engineered soils. Ecology's current CSWGP became effective January 1, 2021, and it expires December 31, 2025.

Industrial

Dischargers of stormwater from industrial facilities, including most manufacturing operations, transportation facilities with vehicle maintenance activities, waste management and recycling facilities, and other industrial operations, are required to apply for coverage under Ecology's NPDES Industrial Stormwater General Permit (ISGP). The permit establishes requirements that include developing a site-specific SWPPP and Spill Control Plan, benchmarks for target pollutants in discharges, monitoring and sampling procedures, quarterly and annual reporting to Ecology, and Corrective Action procedures that apply when discharges exceed target benchmarks or water quality limits. Ecology updates the ISGP on a 5-year cycle; the current permit went into effect on January 1, 2020, and expires December 31, 2024.

Local Plans, Policies, and Regulatory Requirements

CITY OF AUBURN

Municipal Stormwater Program and Plans Overview

The City of Auburn manages a municipal separate storm sewer system (MS4) that collects and conveys runoff from streets and properties in the city to nearby streams. The City operates the stormwater system under the regulation of the Western Washington Phase II Municipal Stormwater Permit, which is a general NPDES permit issued by Ecology that applies to regulated municipal systems serving communities with populations less than 100,000. This permit is issued in 5-year terms, and the City has been a Phase II permittee since 2007. The current Phase II Permit became effective August 1, 2019, and it expires July 31, 2024.

The Phase II Permit requires the City to implement a stormwater management program to reduce pollutant discharges from its MS4 and protect water quality in receiving waters. The City's Stormwater Management Program Plan (2022), which is updated annually, documents the City's stormwater management activities for the required program elements identified in the permit, including: stormwater planning; public education and outreach; public involvement and participation; MS4 mapping and documentation; illicit discharge detection and elimination; controlling runoff from new development, redevelopment, and construction sites; operations and maintenance; source control for existing development; compliance with total maximum daily load (TMDL) requirements; and monitoring and assessment. Because the City uses underground injection systems (stormwater drywells) to discharge stormwater to the ground in certain areas, the City's stormwater management program also addresses Underground Injection Control (UIC) program requirements of the federal Safe Drinking Water Act and Ecology UIC program rules, where applicable (i.e., where stormwater is discharged to the ground through injection wells [stormwater drywells] and not to the MS4 and surface waters).

The City regulates and reviews proposals for new development, redevelopment, and construction sites for compliance with stormwater management requirements contained in the City's Surface Water Management Manual (SWMM), which is adopted by reference in Auburn City Code (ACC) Chapter 12.04 (Public Works Construction Standards). The City's SWMM consists of Ecology's 2019 Stormwater Management Manual for Western Washington (Ecology, 2019) and the City's Supplemental Manual to 2019 Stormwater Management Manual for Western Washington (City of Auburn, 2019).

The City's Community Development Department and Public Works Department review stormwater site plan reports and engineering plans for private and public projects to ensure compliance with the SWMM and NPDES permit requirements. Permitting requirements for

connections to or alterations of public and private storm drainage facilities are contained in ACC Chapter 13.48 (Storm Drainage Utility), which references the requirements of the City's SWMM.

The City's Storm Drainage Utility coordinates the City's municipal NPDES permit compliance efforts and leads efforts to manage flooding in the City. In order to effectively plan for future activities and improvements for the storm drainage system, the City has undertaken comprehensive planning efforts specific to stormwater management that go beyond regulatory compliance. The most recent planning effort was documented in the City's Comprehensive Storm Drainage Plan (Brown and Caldwell, 2015), which provides an implementation plan for future actions and decisions related to storm drainage in the City based on an asset management approach.

Stormwater Design Standards

The City's stormwater regulations contain specific requirements for managing stormwater quality and quantity from new development and redevelopment. The City's minimum standards for new development and redevelopment are listed in ACC Chapter 13.48.225 (Drainage Standards). Key requirements of this code section include:

5. On-Site Stormwater Management. Where appropriate, projects shall employ on-site storm water management BMPs to infiltrate, disperse, and retain storm water runoff on site to the maximum extent feasible without causing flooding, erosion, water quality or groundwater impacts. The city requires the use of low impact development (LID) principles and BMPs using the project thresholds, standards, and requirements presented in the SWMM to meet this requirement. The city shall require low impact development (LID) designed in accordance with the SWMM.

6 Runoff Treatment. All projects that meet the thresholds for runoff treatment in the SWMM shall provide water quality treatment in accordance with the SWMM. The use of emerging technologies for storm water treatment will be considered in accordance with the SWMM.

7. Flow Control (Detention). All projects that meet the thresholds for flow control in the SWMM shall provide flow control in accordance with the SWMM. Additionally, all projects shall address the need to provide water quality controls according to the design criteria as determined by the city engineer. The requirement for storm water detention will also be determined by pipe capacity and storm water discharge location, as provided in the SWMM.

9.3 Current Conditions

The City's Downtown study area encompasses approximately 376 acres of highly developed land in Auburn's urban center. There are no mapped streams in the Downtown study area. Based on drainage sub-basin maps included in the City's Comprehensive Drainage Plan (2015), the western portion of the Downtown study area – generally west of Auburn Way/Auburn Ave. – drains west to Mill Creek. The eastern part of the study area – generally east of Auburn Way/Auburn Ave. – drains east to the Green River. Stormwater runoff from the extensive impervious surfaces in the Downtown study area reaches Mill Creek and the Green River through a network of catch basins, pipes, and outfalls that are part of the City's MS4.

FIGURE 9-1 Map of existing stormwater system

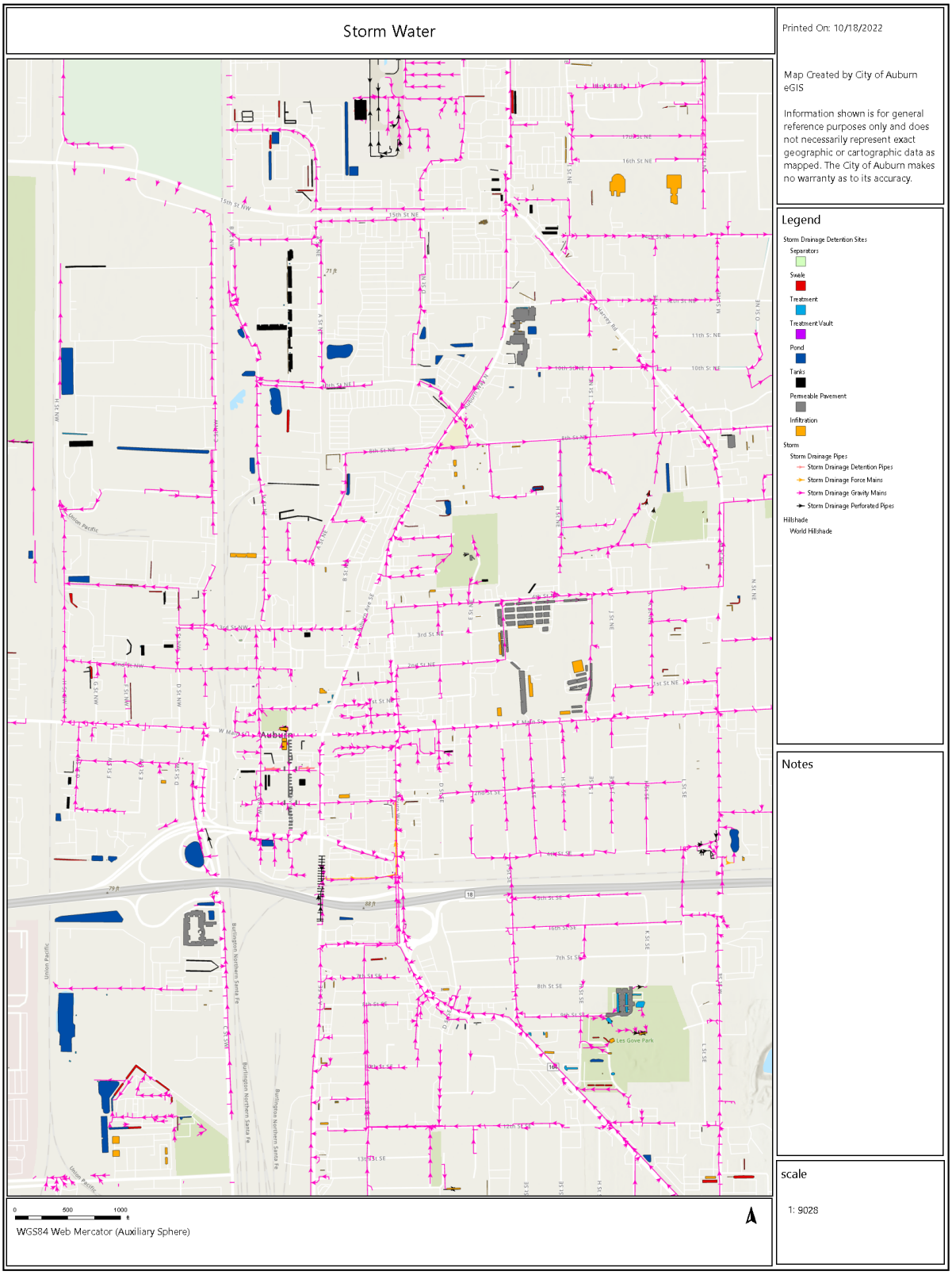
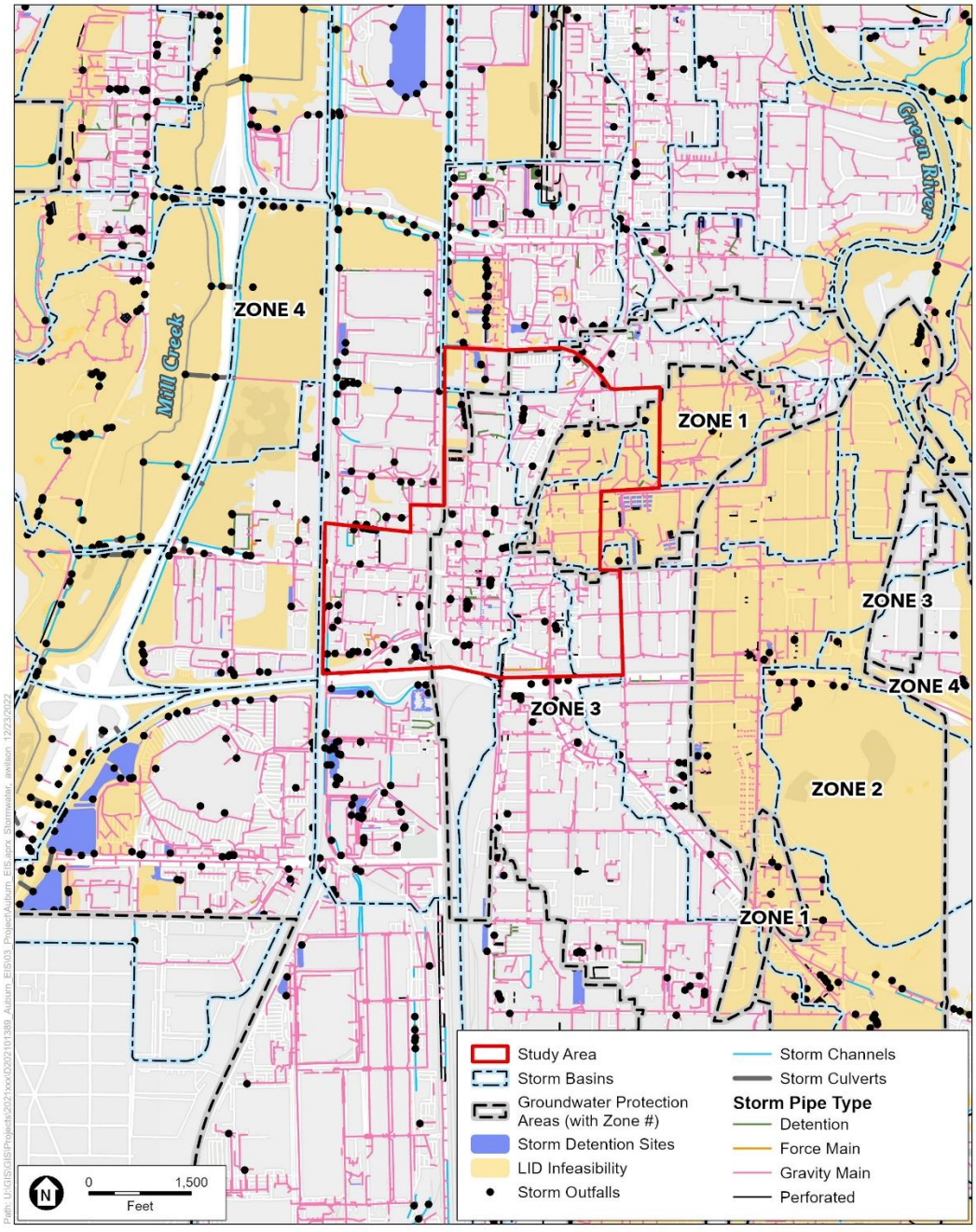


FIGURE 9-2 Map of wellhead protection zones



SOURCE: City of Auburn, 2022; ESA, 2022

City of Auburn Downtown EIS

Figure 8-1
Stormwater Map

ESA

Source: ESA

The City identifies the northeastern part of the Downtown study area – generally east of Auburn Ave. and north of Main St. – as within the City's Groundwater Protection Zone 1, where infiltration of stormwater runoff from pollutant generating surfaces is not allowed without enhanced treatment and approval from the City engineer, per the City's SWMM. The remainder of the Downtown study area is not identified as an area where LID infiltration is infeasible, based on mapping in the City's SWMM (Supplemental Manual to the 2019 Western Washington SWMMM).

9.4 Key Findings and Implications for Plan

The following topics related to utilities and stormwater should be considered in the development of the City of Auburn Downtown Subarea Plan:

- The City has regulations that must be adhered to in terms of utilities and stormwater. The City's Storm Drainage Utility coordinates the City's municipal NPDES permit compliance efforts and leads efforts to manage flooding in the City. In order to effectively plan for future activities and improvements for the storm drainage system, the City has undertaken comprehensive planning efforts specific to stormwater management that go beyond regulatory compliance.
- The City identifies the northeastern part of the Downtown study area – generally east of Auburn Ave. and north of Main St. – as within the City's Groundwater Protection Zone 1, where infiltration of stormwater runoff from pollutant generating surfaces is not allowed without enhanced treatment and approval from the City engineer, per the City's SWMM.
- Proposed development and growth should take into consideration potential adverse impacts to stormwater from potential increases in impervious surface.
- Public utilities should be upgraded and increased as necessary to accommodate growth and development.
- Attention to proper monitoring of water quality is crucial to public health and safety.

SECTION 10 ACRONYMS

Acronym	Definition
ADA	Americans with Disabilities Act
BMPs	best management practices
CAP	Climate Action Plan
CFR	Code of Federal Regulations
cfs	cubic feet per second
CWA	Clean Water Act
DOT	Department of Transportation
FEMA	Federal Emergency Management Agency
FIRM	Flood Insurance Rate Map
GMA	Washington State's Growth Management Act
GPCD	gallons per capita per day
I-	Interstate
ILA	Interlocal Agreement
ISGP	Industrial Stormwater General Permit
ITS	Intelligent Transportation Systems
LED	light-emitting diode lighting
LEED	Leadership in Energy and Environmental Design
LID	Low Impact Development
LNG	Liquefied Natural Gas
LUSTs	leaking underground storage tanks
MGD	million gallons per day
MS4s	Municipal Separate Storm Sewer Systems
NAICS	North American Industry Classification System
NEC	National Electrical Code
NESC	National Electric Utility Safety Code
NFIP	National Flood Insurance Program
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Places
OSHA	Occupational Safety and Health Administration
PFS	Public Facilities and Services
PSCAA	Puget Sound Clean Air Agency

Acronym	Definition
PSE	Puget Sound Energy
PSRC	Puget Sound Regional Council
RCW	Revised Code of Washington
RSLR	Relative sea level rise
SBCC	Washington State Building Code Council
SEPA	State Environmental Policy Act
SIP	State Implementation Plan
SMA	Washington State Shoreline Management Act
SMGM	Stormwater Management Guidance Manual
the Plan	Subarea Plan
THPO	Tribal Historic Preservation Offices
TPY	tons per year
USC	United States Code
UFMP	Urban Forest Management Plan
USTs	underground storage tanks
WAC	Washington Administrative Code
WHR	Washington Heritage Register
WISAARD	Washington Information System for Architectural and Archaeological Records Database
WSDOT	Washington Department of Transportation

SECTION 11 REFERENCES

Land Use/Urban Form

City of Auburn. *Auburn Downtown Plan/Final EIS*. May 2001. September 2022. https://weblink.auburnwa.gov/External/docview.aspx?dbid=0&openfile=true&id=167764&cr=1

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Natural Environment

King County iMAP – Critical Areas

City of Auburn GIS – Critical Areas

King County Flood Control District - Lower Green River Corridor Flood Hazard Management Plan (Interactive Map)

City of Auburn Plan Annex - King County Hazard Mitigation Plan, 2019 https://cdn5-hosted.civiclive.com/UserFiles/Servers/Server_11470554/File/City%20Hall/Emergency%20Preparedness/Local%20Hazards/HazardMitigationPlan.pdf

King County Public Health, Heat Mapping Project (https://kingcounty.gov/depts/dnrp/newsroom/newsreleases/2022/June/24-extreme-heat-mitigation-strategy.aspx)

Housing and Economics

City of Auburn. *Housing Action Plan*. June 2021. Accessed July 2024. https://ehq-production-us-california.s3.us-west-1.amazonaws.com/9cfa57f62f9594ff243282e97b3763a79f415246/original/1630449925/676ef034e9f42fffa88a426a4cb40c78_Final_Auburn_HAP.pdf?X-Amz-Algorithm=AWS4-HMAC-SHA256&X-Amz-Credential=AKIA4KKNQAKICO37GBEP%2F20240724%2Fus-west-1%2Fs3%2Faws4_request&X-Amz-Date=20240724T190548Z&X-Amz-Expires=300&X-Amz-SignedHeaders=host&X-Amz-Signature=5d5082d1037aa49841ddd2efd505d6cbfddd213d795583b70bd44068818befba

King County. The King County Buildable Lands Report. July 23, 2014. Accessed September. https://cdn.kingcounty.gov/-/media/king-county/depts/executive/performance-strategy-budget/regional-planning/buildable-lands-report/king-county-buildable-lands-report-2014.pdf?rev=f0c8df82fdab4ab4aeda6516f5a97ad7&hash=33FB76615DA41065BD782D455F44427A

[Additional sources referenced within the section]

Transportation

Highway Capacity Manual 6th Edition

2001 Auburn Downtown Plan

Comprehensive Downtown Parking Management Plan (CDPMP), adopted January 2014
City's 2020 Local Road Safety Plan

Washington State Freight and Goods Transportation System (FGTS) 2021 Update
Auburn Downtown Plan & EIS (2001)

Comprehensive Downtown Parking Management Plan (2014)
City of Auburn Local Road Safety Plan (2022)

Public Services

City of Auburn's 2022-2027 Capital Facilities Plan

Valley Regional Fire Authority 2021-2017 Capital Facilities Plan

Utilities, Stormwater and Water Quality

Auburn City Code. Chapter 13.48. Storm Drainage Utility. Current June 6, 2022.

City of Auburn Downtown Plan/Final EIS. May 2001.

City of Auburn Comprehensive Storm Drainage Plan Report and Appendices. Prepared by Brown & Caldwell. December 2015.

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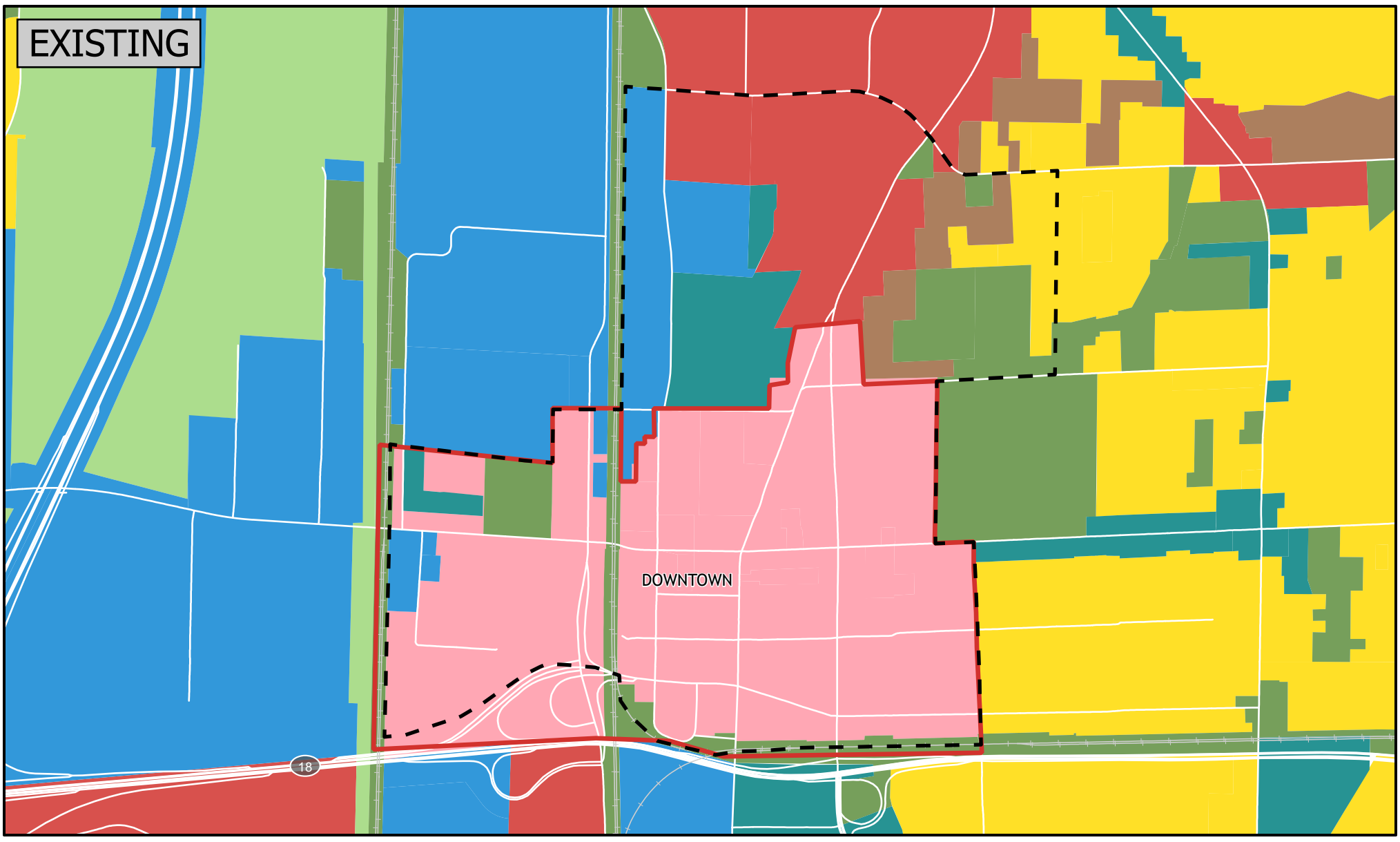
City of Auburn Downtown Urban Center Map 3.

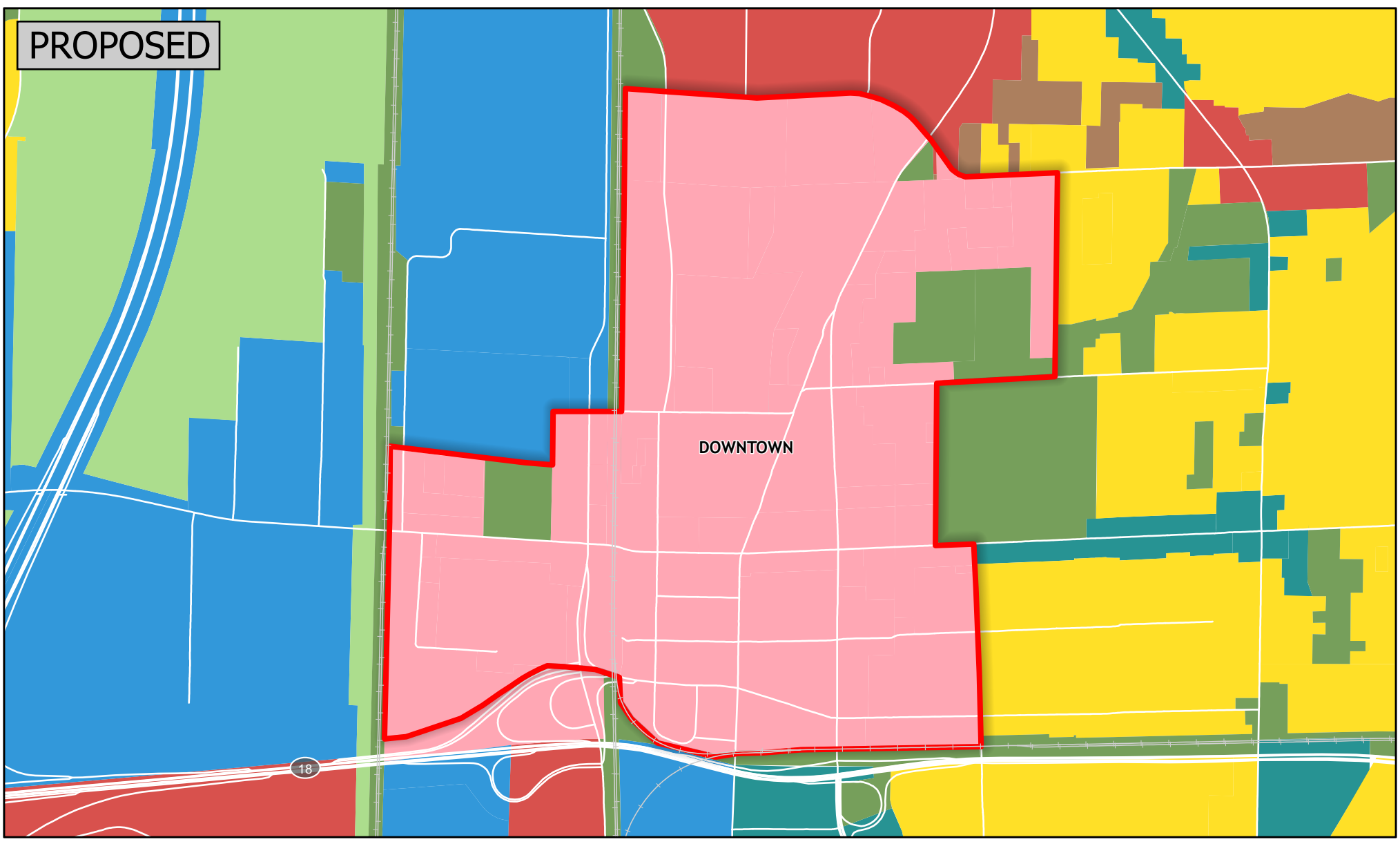
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EXHIBIT 5
COMPREHENSIVE LAND USE MAP UPDATE





Ord. No. 6997

- Commercial
- Downtown Urban Center
- Neighborhood Residential Two
- Neighborhood Residential Three
- Open Space
- Public/Quasi-Public
- Mixed-Use
- Industrial
- Existing Downtown Urban Center
- Expanded Downtown Urban Center
- Proposed Downtown Urban Center

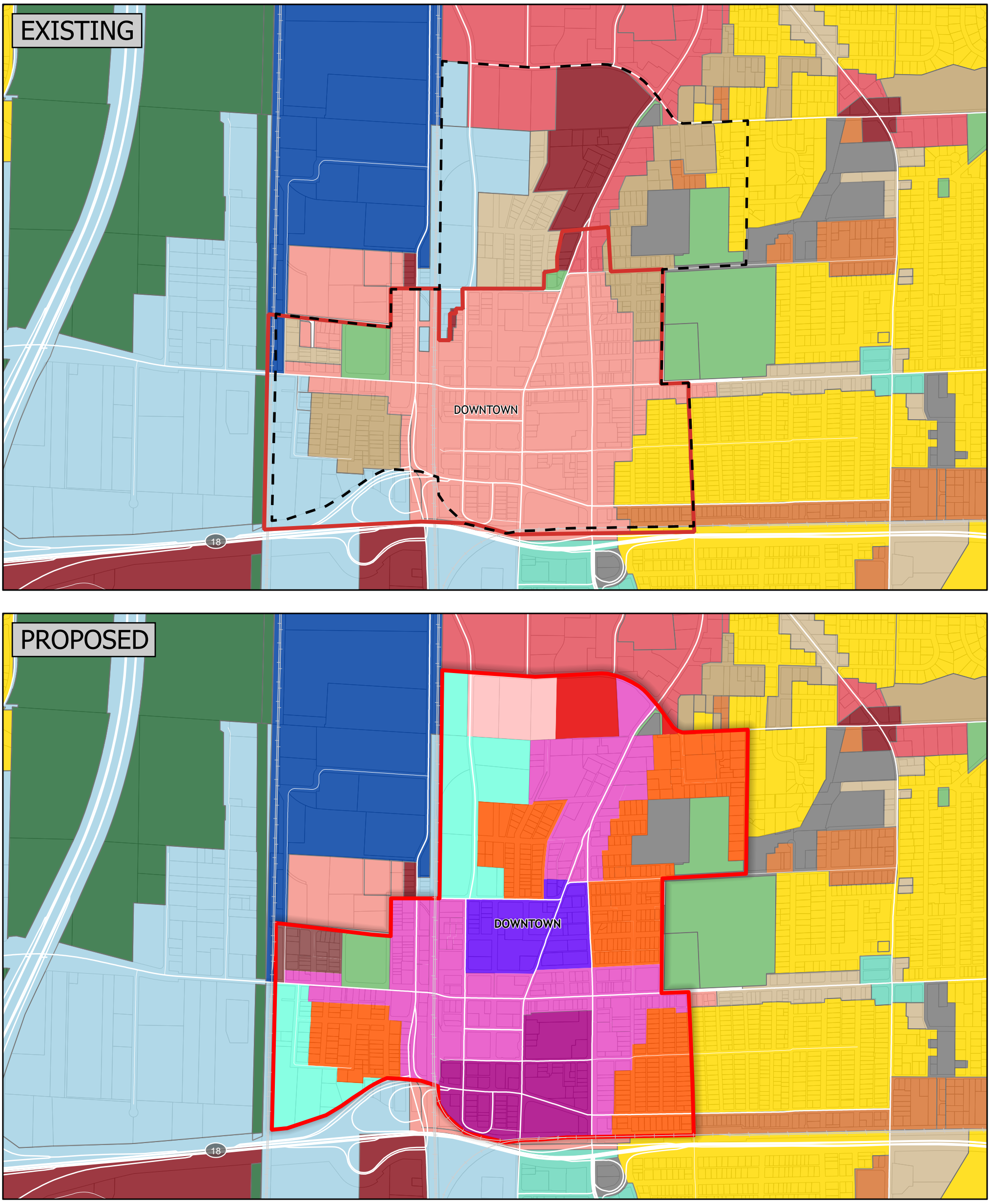
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MILES

Printed On: 10/3/2025

Map ID: 6354

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EXHIBIT 6
COMPREHENSIVE ZONING MAP UPDATE



Ord. No. 6997

- DUC - Core 125
- DUC - Core 75
- DUC - FR Flex-Residential
- DUC - Health & Wellness 125
- DUC - C-2 Heavy Commercial
- DUC - C-1 Light Commercial
- DUC - M-1 Light Industrial
- DUC - NR Neighborhood Residential
- DUC - Downtown Urban Center
- C-1 - Light Commercial
- C-2 - Heavy Commercial
- I - Institutional
- M-1 - Light Industrial
- M-2 - Heavy Industrial
- Open Space
- P-1 - Public Use
- R-2 - Residential Low
- R-3 - Residential Moderate
- R-4 - Residential High
- R-NM - Neighborhood Mixed Use
- R-F - Residential Flex
- Existing Downtown Urban Center
- Expanded Downtown Urban Center
- Proposed Downtown Urban Center

0 0.25 0.5

Miles

Printed On: 10/3/2025

Map ID: 6355

Information shown is for general reference purposes only and does not necessarily represent exact geographic or cartographic data as mapped. The City of Auburn makes no warranty as to its accuracy.

EXHIBIT 7

Alexandria Teague

From: Guida, Eric (COM) <eric.guida@commerce.wa.gov>
Sent: Tuesday, October 21, 2025 10:44 AM
To: Alexandria Teague
Cc: Alyssa Tatro; Steven Sturza
Subject: RE: Updated downtown subarea plan

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

Good morning Alexandria, as well as Alyssa and Steven,

Thank you for sharing the land use and zoning maps for your downtown subarea plan in Planview submittal #2025-S-10965.

We commend Auburn for updating the draft version of the subarea plan to address our displacement concerns. DP-H-7, -8, -9, and -10 all provide the city with direction to address and prevent displacement as development occurs in the subarea.

We have no comment on the land use and zoning maps themselves. Please note, however, that per 2025's Transit Oriented Development legislation in HB1491, a half-mile station area will need to established and likely upzoned by 2029.

I will mark Planview submittal #2025-S-8176A as a duplicate submission to -10965, Alexandria.

Best,

Eric Guida | Senior Planner
Direct: 360.725.3044
Email: eric.guida@commerce.wa.gov

https://www.commerce.wa.gov/serving-communities/growth-management/

From: Alexandria Teague <ateague@auburnwa.gov>
Sent: Tuesday, October 14, 2025 3:24 PM
To: Guida, Eric (COM) <eric.guida@commerce.wa.gov>
Cc: Alyssa Tatro <ATatro@auburnwa.gov>; Steven Sturza <ssturza@auburnwa.gov>
Subject: Updated downtown subarea plan

External Email

Hi Eric,

I highlighted the added anti-displacement policies. Please let staff know if you have any comments. We are going to planning commission on 10.21 and then to a public hearing on 11.5. If any modifications are needed, staff needs time to review and incorporate in the subarea plan before items are due for the hearing.

Thank you!

Alexandria

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

If inquiring about a specific site, please include the parcel number or address, or if inquiring about a specific project, please include the City project number in your email.

Alexandria D. Teague, AICP, Planning Services Manager
Department of Community Development
City of Auburn | www.auburnwa.gov
253.931.3003 | ateague@auburnwa.gov
Mailing Address: 25 W Main Street, Auburn, WA 98001
Permit Center Address: 1 E Main Street, Auburn, WA 98002 (Click Here for Map)
Customer Service Survey | https://www.surveymonkey.com/r/XNSL95J
Application Forms | http://www.auburnwa.gov/services/resource_library/forms.htm
Zoning Maps | http://www.auburnwa.gov/services/resource_library/maps.htm

This email and your response are considered a public record and can be subject to disclosure under Washington's Public Records Act.

From: Guida, Eric (COM) <eric.guida@commerce.wa.gov>
Sent: Thursday, October 9, 2025 10:16 AM
To: Alexandria Teague <ateague@auburnwa.gov>
Subject: RE: Acknowledge-Letter-2025-S-8176A & Acknowledge-Letter-2025-S-10965

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

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Hi Alex,

I've reached out to Planview tech support to see if we can mark 2025-S-10965 as a request for expedited review.

In any case, I've given our housing planners a heads up, and I know they plan do review the submittal next week, so we can have comments, if there are any, to you by your 10/21 meeting.

Eric Guida | Senior Planner
Direct: 360.725.3044
Email: eric.guida@commerce.wa.gov

https://www.commerce.wa.gov/serving-communities/growth-management/

From: Alexandria Teague <ateague@auburnwa.gov>
Sent: Wednesday, October 8, 2025 1:56 PM
To: Guida, Eric (COM) <eric.guida@commerce.wa.gov>
Subject: Acknowledge-Letter-2025-S-8176A & Acknowledge-Letter-2025-S-10965

External Email

Hi Eric,

I think I messed something up. I did a supplement to the existing downtown plan and I received two acknowledgment letters. Also I did not see where to do the expedited. Is it possible to change it to expedited at this time?

Thank you!

Alex

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

If inquiring about a specific site, please include the parcel number or address, or if inquiring about a specific project, please include the City project number in your email.

Alexandria D. Teague, AICP, Planning Services Manager
Department of Community Development
City of Auburn | www.auburnwa.gov
253.931.3003 | ateague@auburnwa.gov
Mailing Address: 25 W Main Street, Auburn, WA 98001
Permit Center Address: 1 E Main Street, Auburn, WA 98002 (Click Here for Map)
Customer Service Survey | https://www.surveymonkey.com/r/XNSL95J
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Alexandria Teague

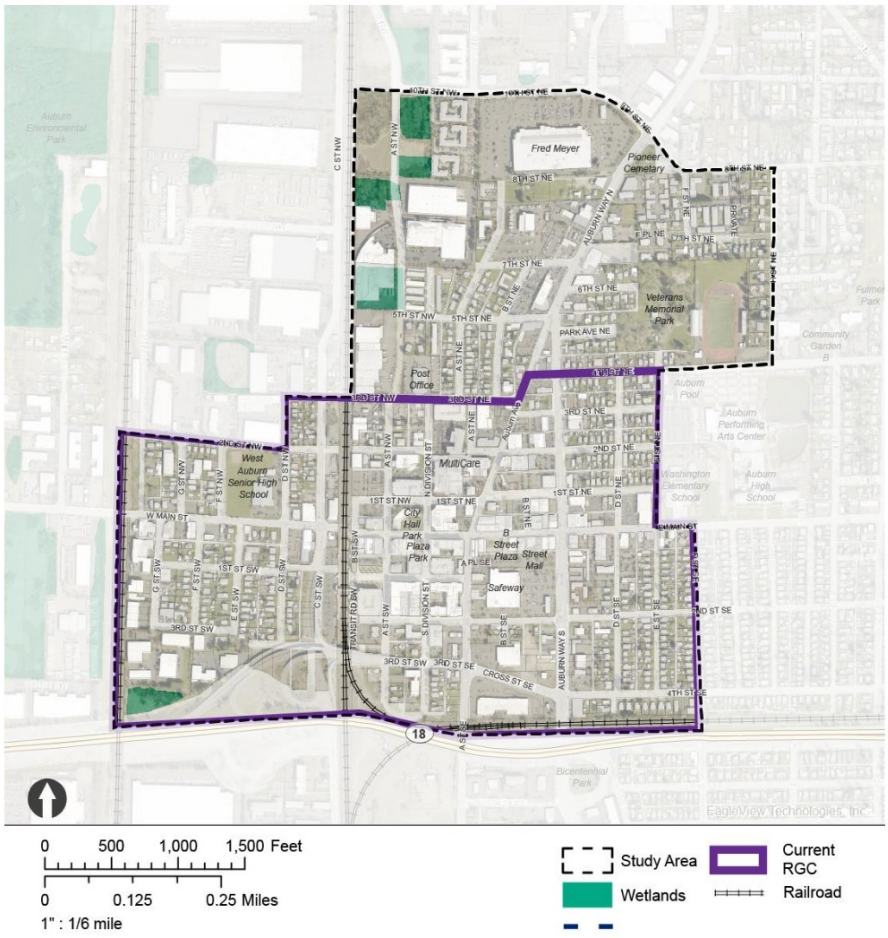
From: Alexandria Teague
Sent: Friday, October 24, 2025 7:20 PM
To: 'mypeabody62@gmail.com'
Subject: Regarding 2024 - Downtown Subarea Plan

Good evening Ms. Adams,

It was nice to speak with you today. As requested, I am providing information about the proposed downtown subarea plan and associated land use and zoning map amendments. The City of Auburn has prepared a new subarea plan for the downtown area (called the 2024 Auburn Downtown Subarea Plan). It represents a full update and rethinking of the downtown area and incorporates changing conditions and characteristics, and new community, city leadership, and staff visions for downtown. The last update to the downtown subarea plan was completed in 2001. It provided direction for the development of the downtown area over the past 20 years. The 2001 Auburn Downtown Plan (or 2001 Plan) set a vision and strategies for a vibrant, compact, mixed-use urban downtown core. Over the past 20 years downtown Auburn has seen significant public investments, as well as private development, that have transformed several blocks within the downtown into a strong, pedestrian-oriented center. While the 2001 Plan has been highly successful due to the dedication of time, financial commitments, and contributions from the community, we are now ready to plan for the next 20 years.

As part of new subarea plan the downtown area has been expanded north. The downtown area boundary is being expanded north of 3rd St NE so that the city can accommodate additional growth – new opportunities for residential and commercial growth, while capitalizing on the new King County Rapid Ride – I Line. This expands the current downtown area boundary from 233 acres to approx. 361 acres (see Figure 1). Your property is included in this expanded boundary.

FIGURE 1-1 Study Area Map



SOURCES: MAKERS (City of Auburn GIS data).

Your property is currently zoned R-F, Residential Flex. It is circled below in the 1st excerpted zoning map. The R-F zone is intended primarily to accommodate small-scale business and professional offices, salons and other personal services, eating and drinking establishments, where they are compatible with residential uses. In terms of residential uses it allows for single family residences and middle housing (i.e. duplex to sixplex). The maximum height in the R-F zone is 45 ft. The full description, list of allowed uses, and zoning development standards (e.g. max height) for the R-F zone is within Chapter 18.07 of the Auburn City Code (ACC): https://auburn.municipal.codes/ACC/18.07. Your property is currently proposed to be rezoned to Downtown Urban Center (DUC) Core-75 (circled below in the 2nd excerpted zoning map).

Please note that the map amendment will not result in any sort of eminent dominant action. Nor will you be required to sell or make changes to your property. Your property currently features a triplex and can continue to do so in the future. Anti-displacement policies have been added to the downtown subarea plan, including a policy that if a middle housing development (i.e. a triplex) needs to be rebuilt it may do so in the same footprint without having to meet current zoning development standards.

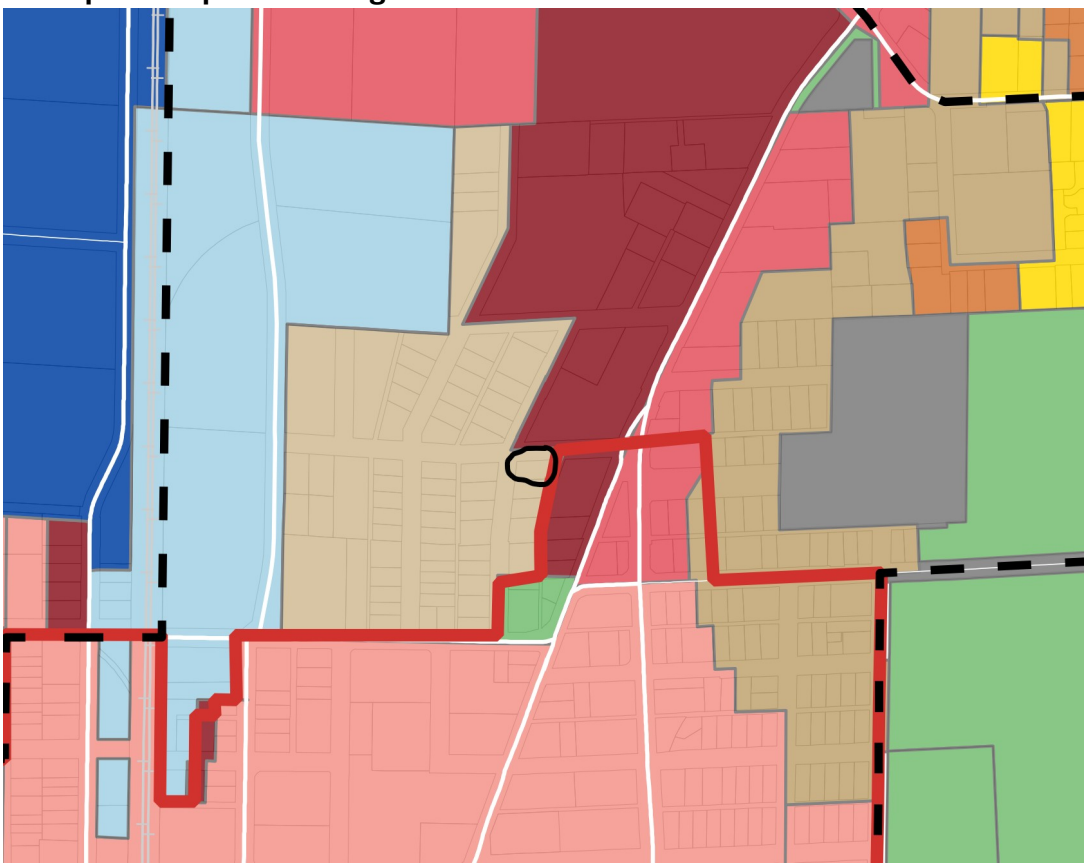
The Core-75 zone allows for more intense residential development – such as multi-family (7 units or more), co-living housing units (currently proposed as a text amendment to City code), as well as mixed use (e.g. a building with first floor commercial and residential above it). Currently, it is not anticipated to

allow for middle housing as it is intended for more dense development, and features a maximum building height of 75 ft.

As I thought more about our phone call, it is not likely a sixplex (3 additional housing units) would be allowed, as it would constitute middle housing. Multi-family, 4 additional housing units, for a total of 7 housing units, on site would be permissible. It may also be permissible to add co-living housing units to your property. I pasted a snippet of building forms and land uses proposed for the DUC Core districts. I also mentioned that parking rates for multi-family is now 0.5 per unit. Seven housing units would require a total of 4 parking stalls. I do recommend talking with staff further about accommodating additional units on your property. It'll help you determine how many units are actually feasible; especially on/within an existing building. It appears that there are many options that you could pursue. I would be happy to chat with about it more with you.

Staff is preparing to take the subarea plan to Planning Commission on November 5th for a public hearing. The meeting is at 7pm in Council Chambers. I am very glad you reached out and I encourage you to attend. You may also attend via zoom. The public hearing details are here: NOH 2024 DOWNTOWN SUBAREA PLAN - City of Auburn.

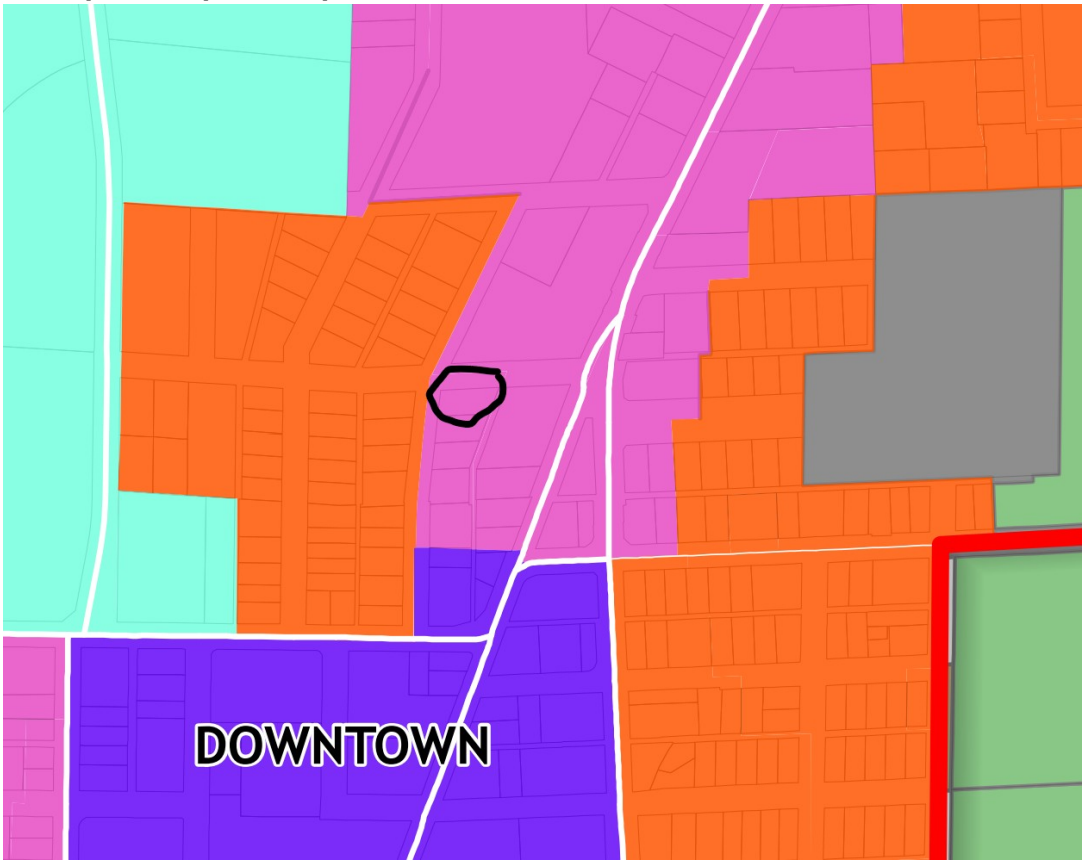
Excerpted Map 1 – Existing Zones



Ord. No. 6997

- DUC - Core 125
- DUC - Core 75
- DUC - FR Flex-Residential
- DUC - Health & Wellness 125
- DUC - C-2 Heavy Commercial
- DUC - C-1 Light Commercial
- DUC - M-1 Light Industrial
- DUC - NR Neighborhood Residential
- DUC - Downtown Urban Center
- C-1 - Light Commercial
- C-2 - Heavy Commercial
- I - Institutional
- M-1 - Light Industrial
- M-2 - Heavy Industrial
- Open Space
- P-1 - Public Use
- R-2 - Residential Low
- R-3 - Residential Moderate
- R-4 - Residential High
- R-NM - Neighborhood Mixed Use
- R-F - Residential Flex
- Existing Downtown Urban Center
- Expanded Downtown Urban Center
- Proposed Downtown Urban Center

Excerpted Map 2 – Proposed Zones



Snippet of uses in the DUC Core.

DUC – Core

The Downtown Urban Center zoning district encourages higher density residential compared to other areas of the city and mixed-use buildings. Other commercial uses are allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. (see Pedestrian Streets) per the City's currently adopted Downtown Design Guidelines.

Building Form

Expected Building Types	Development Standards
▪ Mid-rise apartments ▪ Office buildings ▪ Parking structures	▪ Maximum height 75-125 feet depending on area ▪ FAR based on location, use mix, and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Retail/residential vertical mixed-use ▪ Office commercial ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Restaurants/bars ▪ Craft industry/light industrial ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage and sales ▪ Most industrial uses ▪ Self-storage ▪ On Pedestrian I Streets: Drive-throughs

Development Examples



L-R: Mixed-use buildings in Salem, OR; Seattle, WA; and Kirkland, WA

Sincerely,

Alexandria

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

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Alexandria D. Teague, AICP, Planning Services Manager

Department of Community Development
City of Auburn | www.auburnwa.gov
253.931.3003 | ateague@auburnwa.gov
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This email and your response are considered a public record and can be subject to disclosure under Washington's Public Records Act.

From: Kim Adams <mypeabody62@gmail.com>
Sent: Thursday, October 23, 2025 2:23 PM
To: Planning <planning@auburnwa.gov>; Kim Adams <mypeabody62@gmail.com>
Subject: Regarding 2024 - Downtown Subarea Plan

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

---

Good Day, To Whom this may concern

I am the owner of the following property:
422 B Street NE, Auburn, Washington 98002

My email: **mypeabody62@gmail.com**
My contact number is: **(206)856-3430**

This email is in response to a notification I received in the mail for
The Public Hearing 2024 Downtown Subarea Plan
I am trying to make sense of all the verbiage & maps in this plan.
It is not easy to understand, at least for me.

Could someone please call or email me to let me know what is taking place?
How is this plan going to affect my property?
What is the ETA for all this to be put into motion?

I purchased this property as a retirement investment, as my employers did not offer a retirement plan or 401 (k). So now it's finally paid off, and the City of Auburn - YOU want my property, is this what you are saying? IF SO...

How will I be compensated for the lost rents that I was banking on in my golden years, which are my current income as we speak, due to health issues, etc.?

Well, can you answer this?

It's not like I can turn the clock back and start over. One cannot grow younger, only older.
I thought I invested efficiently and wisely. Told to purchase real estate - great investment... So I did, and now this!!!
What about the tenants and the new laws that protect them and their rents?
Is that going to be compensated? WELL, or is that a loss for me?

Even if you pay me the fair market price, I could not afford to purchase another of equal value and return in an inflated market that would have no payment and three rents, that is if I could even get approved. If I were to get approved, well, essentially it would be placing me in DEBT!

How will I be compensated? regarding the following...
Rental income & the increases over the years to come?
I planned on subsidizing my Social Security with these rents.
The Equity property value increases, etc.
How will I be compensated for those things?
The property value price today is not compensation; it's an insult!
If I wanted to sell the property, I could do that anytime, so getting just the value is not compensation. So, if the city thinks that is fair compensation, they are very much mistaken.

Let me remind you - it's our property taxes that helped build the City of Auburn. We deserve fair, respectable COMPENSATION.

I want to be fairly compensated for what I've invested in for years. A compensation that will cover me as I planned on and sacrificed for. I deserve that, The American Dream - What good is it to dream and be an American if our Governments, Cities, and those in power can pull the carpet out from underneath us at any given moment, give us what they feel is just then use excuses, guilt trips and justifications like it's best for the community, the community that did not pay the taxes for that lot over the years like I did.

I am very upset. I am sure you got the gist. Sorry, but I want answers and want to know how I will be compensated.

Regretfully
Kimberly J. Adams

Alexandria Teague

From: Alexandria Teague
Sent: Thursday, October 30, 2025 5:36 PM
To: JEFFREY OLIPHANT
Cc: Steven Sturza; Dinah Reed; Shannon Howard
Subject: RE: 2024 Downtown Auburn Subarea Plan - Proposed Non-Project Action

Hi Jeff,

I think you are referring to ACC 18.29.060(G) (below); that is a requirement in code. As a follow-on project, we will be evaluating the downtown design standards and downtown code (Chapter 18.29 ACC). At this time, I cannot say that provision whether will be removed or retained. We will bring these future updates to Planning Commission – you can keep up on future Planning Commission meetings on this page: https://www.auburnwa.gov/city_hall/public_meetings.

G. Minimum Building Height. The minimum height for any new structure within the DUC zone shall be two stories for the full extent of the building footprint.

Alexandria

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

If inquiring about a specific site, please include the parcel number or address, or if inquiring about a specific project, please include the City project number in your email.

Alexandria D. Teague, AICP, Planning Services Manager
Department of Community Development
City of Auburn | www.auburnwa.gov
253.931.3003 | ateague@auburnwa.gov
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From: JEFFREY OLIPHANT <jlo55@aol.com>
Sent: Monday, October 27, 2025 5:03 PM
To: Alexandria Teague <ateague@auburnwa.gov>
Cc: Steven Sturza <ssturza@auburnwa.gov>; Dinah Reed <DReed@auburnwa.gov>; Shannon Howard <showard@auburnwa.gov>
Subject: 2024 Downtown Auburn Subarea Plan - Proposed Non-Project Action

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Hi Alexandria,

Thank you for clarifying and providing he snippets; I will study them over the next day or two.

It appears that in the Core areas there is proposed a minimum FAR of 0.75.
I did NOT see the minimum two story height requirement. Am I correct that it is proposed to no longer be a requirement?

Kind regards.

Jeff

=========

On Monday, October 27, 2025 at 04:43:34 PM PDT, Alexandria Teague <ateague@auburnwa.gov> wrote:

> Hi Jeff,
>
> Let me clarify – I mentioned “at this time…” That is because the EIS evaluated the impacts of the current proposed boundary, which was finalized on Jan. 22, 2025. The Downtown Subarea Plan is based on the evaluation completed under the EIS.
>
> You are correct that the purpose of the public hearing to receive public input on the Downtown Subarea Plan before decision makers make the decisions. We welcome your comments, questions, and attendance at the public hearing.
>
> I pasted a snippet of the Core and Health & Wellness Districts. The DUC Core covers both the 75 and 125; the difference is in the height. The Health & Wellness is really focused on the already existing medical buildings.

DUC – Core

The Downtown Urban Center zoning district encourages higher density residential compared to other areas of the city and mixed-use buildings commercial uses are allowed. Retail, residential, and personal service storefronts are required on designated Pedestrian I streets. (see Pedest Streets) per the City's currently adopted Downtown Design Guidelines.

Building Form

Expected Building Types	Development Standards
▪ Mid-rise apartments ▪ Office buildings ▪ Parking structures	▪ Maximum height 75-125 feet depending on area ▪ FAR based on location, use mix, and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Retail/residential vertical mixed-use ▪ Office commercial ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Restaurants/bars ▪ Craft industry/light industrial ▪ Arts/entertainment (gallery, theater, fine arts studio)	▪ FAR below 0.75 ▪ Outdoor storage ▪ Most industrial u ▪ Self-storage ▪ On Pedestrian I S

DUC – Health and Wellness

The Downtown Urban Center – Medical zoning district encourages grov medical and medical office uses in downtown. High-density residential use development and other commercial uses are also allowed. Retail, residential, and personal service storefronts are required on designate Pedestrian I streets. This zone is designed to build upon and replace the Residential Office Hospital zone (RO-H).

Building Form

Expected Building Types	Development Standards
▪ Medical/office buildings ▪ Mid-rise apartments ▪ Parking structures	▪ Maximum height 125 feet ▪ Reduced height allowances for non-medical uses ▪ FAR based on use mix and bonuses ▪ No maximum density

Land Use

Allowed Uses	Prohibited
▪ Medical offices and services ▪ Hospital-related ▪ Office commercial ▪ Retail/residential vertical mixed-use ▪ Retail ▪ Multifamily residential (apartments and co-living housing) ▪ Food production, i.e. brewery, coffee roastery	▪ FAR belov ▪ Outdoor s ▪ On Pedes ▪ Most indu ▪ Self-stora

Thank you,

Alexandria

Planning or Land Use Questions?

Book an online meeting with staff.

Check out our FAQ!

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Alexandria D. Teague, AICP, Planning Services Manager

Department of Community Development

City of Auburn | www.auburnwa.gov

253.931.3003 | ateague@auburnwa.gov

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From: JEFFREY OLIPHANT <jlo55@aol.com>
Sent: Monday, October 27, 2025 1:30 PM

To: Alexandria Teague <ateague@auburnwa.gov>
Cc: Steven Sturza <ssturza@auburnwa.gov>; Dinah Reed <DReed@auburnwa.gov>; Shannon Howard <showard@auburnwa.gov>
Subject: 2024 Downtown Auburn Subarea Plan - Proposed Non-Project Action

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Hi Alexandria,

Than you for the prompt reply and additional information.

In quickly skimming over the info, I did not see (and would like to learn more about) proposed zones

Health and Wellness 125

Core 125

Core 75

After reading the info concerning the above 3 zones, I may not have any concerns, however as a general matter, your comment that it was not feasible to change boundaries surprised me a bit. Is not the purpose of the Public Hearing to receive public input on the Non-Project Action / Downtown Subarea Plan before decision makers actually make the decisions? Or were the boundary lines part of an earlier decision that is not alterable / not subject to further consideration?

Thank you for confirming that Kayla (fka Lexi IV) is vested. FYI for you and those copied, in September our teams at Barghausen, Dorbritz and TENW invoiced my company for about 60 work hours on Kayla and I anticipate forthcoming invoices for a good number of October work hours as well; it is our goal to be resubmitting within the next couple of weeks. The instructions to our team were to make sure we fully addressed all City comments.

Again, (a) thanks for your help, and (b) after review of the forthcoming info I may not any concerns.

Kind regards.

Jeff

==========

On Monday, October 27, 2025 at 01:05:36 PM PDT, Alexandria Teague <ateague@auburnwa.gov> wrote:

Hi Jeff,

The boundary is shown in maps in these documents below. The boundary was studied and confirmed as part of the EIS is now final. It is not feasible change the boundary at this time. I understand that Lexi project is located south of 3rd St NW. It is proposed to be changed to the DUC Core-125 zoning district. However, since you have submitted already filed the design review and SEPA applications, the zoning development standards are vested.

2024 Downtown Subarea Plan
Appendix A Planned Action EIS
Appendix B Baseline Report Final
Subarea Land Use Map
Subarea Zoning Map

Please let me know if you'd like to discuss further.

Alexandria

Planning or Land Use Questions?

Book an online meeting with staff.

Check out our FAQ!

If inquiring about a specific site, please include the parcel number or address, or if inquiring about a specific project, please include the City project number in your email.

Alexandria D. Teague, AICP, Planning Services Manager

Department of Community Development

City of Auburn | www.auburnwa.gov

253.931.3003 | ateague@auburnwa.gov

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From: JEFFREY OLIPHANT <jlo55@aol.com>

Sent: Monday, October 27, 2025 11:41 AM
To: Alexandria Teague <ateague@auburnwa.gov>; Planning <planning@auburnwa.gov>
Subject: 2024 Downtown Auburn Subarea Plan - Proposed Non-Project Action

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---

Hi Alexandria and Planning Team,

We received notice of the forthcoming Public Hearing concerning the referenced Non-Action Project; thank you for sending.

We were unable to find the specific boundary map for the proposed Downtown Subarea. We are particularly interested in understanding the proposed southern boundary and wish to confirm the western boundary is the BNSF / Sounder rail line. Kindly provide the same.

Our belief is that the western portion of the southern boundary should be Third Street SW, where it starts to rise above grade at Division Street (or one block east thereof, at A Street SE) and heading west to the western end of the proposed Downtown Subarea.

Thank you for your assistance.

Jeff Oliphant for

Lexi, LLC

========

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Alexandria Teague

From: John Brekke, Leasing-Pacific West Real Estate, LLC <john@PacificWestRE.com>
Sent: Thursday, November 6, 2025 4:34 PM
To: Alexandria Teague
Cc: Jenn Francis; Jason Krum; Steven Sturza; Pacific West Real Estate - Management; Jenn Francis; Emerson Folker
Subject: Re: Public Comment - Downtown Subarea Plan

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Alexandria,

Thank you for providing the Public Works contact.

Also nice to hear that the city is exploring alternatives to the parking trigger. We've continuously owned our downtown full city block and building for over 45 years, so you can imagine we've had over 100+ different tenants in the building. All with various uses and parking requirements through numerous zoning/parking changes. In other locations, we've built and dedicated $1M+ worth of land and infrastructure. We look forward to the potential change in code. It's needed.

We have aligned interests in making Auburn a flourishing city.

John Brekke
Pacific West Real Estate, LLC

john@PacificWestRE.com

o: 425-287-6800

c: 206-227-7990

PACIFIC WEST
REAL ESTATE, LLC

From: Alexandria Teague <ateague@auburnwa.gov>
Sent: Thursday, November 6, 2025 2:12 PM
To: John Brekke, Leasing-Pacific West Real Estate, LLC <john@PacificWestRE.com>
Cc: Jenn Francis <jfrancis@auburnwa.gov>; Jason Krum <jkrum@auburnwa.gov>; Steven Sturza

<ssturza@auburnwa.gov>; Pacific West Real Estate - Management <management@PacificWestRE.com>; Jenn Francis <jfrancis@auburnwa.gov>; Emerson Folker <EFolker@auburnwa.gov>
Subject: RE: Public Comment - Downtown Subarea Plan

Good afternoon John,

Yes, please contact Jacob Sweeting, P.E., City Engineer/Assistant Director Engineering Services (253-804-3118, jsweeting@auburnwa.gov). I didn't put in my email below but also note that the City is exploring alternatives to the 12.64A parking trigger and hope to bring it to council for discussion and consideration next year.

Thank you,

Alexandria

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

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Alexandria D. Teague, AICP, Planning Services Manager
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Zoning Maps | http://www.auburnwa.gov/services/resource_library/maps.htm

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From: John Brekke, Leasing-Pacific West Real Estate, LLC <john@PacificWestRE.com>
Sent: Thursday, November 6, 2025 11:26 AM
To: Alexandria Teague <ateague@auburnwa.gov>
Cc: Jenn Francis <jfrancis@auburnwa.gov>; Jason Krum <jkrum@auburnwa.gov>; Steven Sturza <ssturza@auburnwa.gov>; Pacific West Real Estate - Management <management@PacificWestRE.com>; Nancy Backus <nbackus@auburnwa.gov>; Cheryl Rakes <CRakes@auburnwa.gov>; Jenn Francis <jfrancis@auburnwa.gov>; Emerson Folker <EFolker@auburnwa.gov>
Subject: Re: Public Comment - Downtown Subarea Plan

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

Hi Alexandria,

Thank you for providing the planning commission with my comments.

I also appreciate you forwarding my parking requirement concerns to Public Works. Good to hear that there is a strong possibility of parking requirements being reduced. I hope the City of Auburn takes a closer look at Auburn City Code (ACC) 12.64A.020(F) regardless of the State forcing the issue. Whom might I follow up with in Public Works on this parking matter?

Work still needs to be done in the community. A very significant civil engineering firm publicly spoke to the difficulties of working in the City of Auburn while praising the City of Lacey. I heard the same concerns with Auburn from a large general contractor based the South King County. The GC also praised the City of Lacey. I really want Auburn to succeed and some damage control and PR needs to be done. I'm happy to provide support in this area.

Again, thank you for your help!
John Brekke
Pacific West Real Estate, LLC

john@PacificWestRE.com
o: 425-287-6800

c: 206-227-7990

PACIFIC WEST
REAL ESTATE, LLC

From: Alexandria Teague <ateague@auburnwa.gov>
Sent: Wednesday, November 5, 2025 4:39 PM
To: John Brekke, Leasing-Pacific West Real Estate, LLC <john@PacificWestRE.com>
Cc: Jenn Francis <jfrancis@auburnwa.gov>; Jason Krum <jkrum@auburnwa.gov>; Steven Sturza <ssturza@auburnwa.gov>; Pacific West Real Estate - Management <management@PacificWestRE.com>
Subject: RE: Public Comment - Downtown Subarea Plan

Good afternoon John,

Thank you for your comments. Staff have the following responses to your comments:

- I will pass this onto consideration for Planning Commission tonight.
- The Map 2-2 of the subarea plan is a snapshot in time and was prepared based on King County Assessment data.
  This provision, "*A change in use on the subject property that results in an increase in the required number of parking stalls by five or more*" comes directly from Auburn City Code (ACC)

12.64A.020(F). I understand your concerns, however the Downtown Subarea Plan does not amend this code requirement. I will pass your comments onto the Public Works Department staff. Please also note that based on recent state legislation related to parking, the City will review the parking requirements provided in Chapter 18.52 ACC, and very likely reduce parking requirements citywide, that may help alleviate the occurrence of this requirement.

- I think I can say that we share the same goal of making downtown Auburn to be the most interesting and incentivized place to do development and own real estate in the Puget Sound region. The Subarea Plan and future code updates should help encourage development while meeting City and State code requirements and legislation.

Sincerely,

Alexandria

Planning or Land Use Questions?
Book an online meeting with staff.
Check out our FAQ!

If inquiring about a specific site, please include the parcel number or address, or if inquiring about a specific project, please include the City project number in your email.

Alexandria D. Teague, AICP, Planning Services Manager
Department of Community Development
City of Auburn | www.auburnwa.gov
253.931.3003 | ateague@auburnwa.gov
Mailing Address: 25 W Main Street, Auburn, WA 98001
Permit Center Address: 1 E Main Street, Auburn, WA 98002 (Click Here for Map)
Customer Service Survey | https://www.surveymonkey.com/r/XNSL95J
Application Forms | http://www.auburnwa.gov/services/resource_library/forms.htm
Zoning Maps | http://www.auburnwa.gov/services/resource_library/maps.htm

This email and your response are considered a public record and can be subject to disclosure under Washington's Public Records Act.

From: John Brekke, Leasing-Pacific West Real Estate, LLC <john@PacificWestRE.com>
Sent: Tuesday, November 4, 2025 4:45 PM
To: Planning <planning@auburnwa.gov>
Cc: Jenn Francis <jfrancis@auburnwa.gov>; Emerson Folker <EFolker@auburnwa.gov>; Cheryl Rakes <CRakes@auburnwa.gov>; Nancy Backus <nbackus@auburnwa.gov>; Jason Krum <jkrum@auburnwa.gov>; Pacific West Real Estate - Management <management@PacificWestRE.com>
Subject: Public Comment - Downtown Subarea Plan

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

To the City of Auburn Planning Commission, staff, and elected officials, please incorporate the following comments into the 2024 Downtown Subarea Plan.

- Outright allow medical and wellness uses in DUC-Core 75. Medical uses bring needed people downtown and create foot traffic and higher paying jobs. Don't restrict medical and wellness uses to just DUC - Core 125.

- Current use on Map 2-2 on page 2-4 is inaccurate at 407-435 East Main Street. The current uses are predominately medical.

- Property owners in the DUC shouldn't have to improve frontage, dedicate land, and/or make site improvements when changing the type of tenant increases the site parking requirement by 5 or more vehicles. Property owners need to be able to cycle though different tenants in an existing building without triggering onerous requirements. Example: a 3,000 SF space that has a tenant changeover and the parking requirement goes from 2 parking stalls per 1,000 SF to 4 parking stalls per 1,000 SF would increase the parking requirement by 6 stalls. The 6 parking stall requirement exceeds the 5 parking stall threshold. Therefore, frontage and site improvements/dedication of land would be required. This requirement has created undo vacancy in the DUC. Different types of tenants sign leases in the 1-5 year range. These small tenants often fail or even outgrow particular spaces. Tenants come and go from spaces. Existing property owners need to be able to cycle through tenants without expensive and onerous city requirements. Our family has suffered unnecessary vacancy, loss of rents, and expense due to this city requirement in our DUC building which we have owned for approximately 50 years.

- Puget Sound property owners, developers, general contractors, engineers, brokers, and investors openly consider the City of Auburn as an expensive and burdensome place to do business. More codes and regulations come at a cost and create a dis-incentive. What more can be done in the Downtown Subarea Plan to remove regulations, streamline process, provide incentives, and overall help Downtown Auburn? The City of Auburn and its downtown should be THE most interesting and incentivized place to do development and own real estate in the Puget Sound region.

Thank you,

John W. Brekke, Manager
Auburn Main Street, LLC

Property owner at:
407-435 East Main Street
Auburn, WA 98002

(206) 227-7990 cell
john@PacificWestRE.com
The information contained in this electronic communication is personal, privileged and/or confidential information intended only for the use of the individual(s) or entity(ies) to which it has been addressed. If

you read this communication and are not the intended recipient, you are hereby notified that any dissemination, distribution or copying of this communication, other than delivery to the intended recipient is strictly prohibited. If you have received this communication in error, please immediately notify the sender by reply e-mail. Thank you.
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Alexandria Teague

From: Alexandria Teague
Sent: Wednesday, November 5, 2025 5:22 PM
To: zoies@smallandsons.com
Cc: jsmall@smallandsonsoil.com; steves@smallandsonsoil.com; Steven Sturza
Subject: RE: Comments for Planning Commission Meeting 11/5/2025
Attachments: Zoning_Map.pdf

Good afternoon Zoie,

Thank you for your comment. I will pass it onto the Planning Commission. You are correct that your property located at the intersection of A St NW and 3rd St NW is currently zoned M-1, Light Industrial, and is proposed to be rezoned to DUC Core 75. Your property, however, is currently a non-conforming use and will remain a non-confirming use under the proposed DUC Core 75. The property was zoned M-2, Heavy Industrial around 1964. The use of "bulk storage or processing of oil, gas, petroleum, butane, liquid petroleum, gas and similar products, unless clearly incidental and secondary to support a principally permitted use" was allowed in the M-2 zone previously (it appears to be prior to 2003). This use is not allowed in the M-1 zone; nor is it allowed under the current M-2 zone uses.

As I mentioned, the proposed zoning map amendment or Subarea Plan does not change non-conforming provisions that your project is currently subject to (within Chapter 18.54 ACC) and should not result in a change in your operations.

Below is a code excerpt from 2003 of the uses allowed in the M-2 zone:

18.34.040 Uses requiring a conditional use permit.
The following uses may be permitted when a conditional use permit has been issued pursuant to the provisions of Chapter 18.64:

A. Animal auction houses;
B. Automobile sales new and/or used to include passenger trucks and recreational vehicles;
C. Automobile wrecking and salvage;
D. Animal and food processing including the following:
   1. Tanning and dressing of hides,
   2. Rendering of animal or fish grease or tallow,
   3. Animal slaughtering,
   4. Curing, canning, freezing, canning and processing of meat and seafood,
   5. Pickling and brine curing;
E. Asphalt batch plants;
F. Bulk storage or processing of oil, gas, petroleum, butane, liquid petroleum, gas and similar products, unless clearly incidental and secondary to support a principally permitted use;
G. Bulk storage of explosives and fireworks;
H. Concrete mixing and batching plants, including ready-mix concrete facilities;
I. Drive-in theaters;
J. Government facilities;

Thank you,

Alexandria

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Alexandria D. Teague, AICP, Planning Services Manager
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Zoning Maps | http://www.auburnwa.gov/services/resource_library/maps.htm

This email and your response are considered a public record and can be subject to disclosure under Washington's Public Records Act.

From: Zoie Stacey <zoies@smallandsons.com>
Sent: Wednesday, November 5, 2025 2:20 PM
To: Planning <planning@auburnwa.gov>
Cc: Jeff Small <jsmall@smallandsonsoil.com>; Steve Small <steves@smallandsonsoil.com>
Subject: Re: Comments for Planning Commission Meeting 11/5/2025

CAUTION: The following message originated from outside the City of Auburn. Be careful opening links and attachments

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Zoie Stacey

Executive Assistant

Small & Sons Oil

253-736-6758

zoies@smallandsons.com

From: Zoie Stacey <zoies@smallandsons.com>
Sent: Wednesday, November 5, 2025 2:19 PM
To: planning@auburnwa.gov <planning@auburnwa.gov>
Cc: Jeff Small <jsmall@smallandsonsoil.com>; Steve Small <steves@smallandsonsoil.com>
Subject: Comments for Planning Commission Meeting 11/5/2025

Good afternoon,

I am writing from Don Small & Sons Oil concerning the proposed zoning for Downtown Auburn.

The current zoning updated 12/26/2024 (see attached) does not include our business in that zoning and has us labeled as "Light Industrial". This new proposal does not only exclude us from the light industrial, but it also pulls us into the proposed Downtown Auburn. This new zoning will prevent us from operating the way we have for the last 60+ years, we employ 175+ people across the City of Auburn. The small residential area on our property wouldn't make sense to expand as the train tracks neighbor any residential buildings currently here or plan to be built. The trains making housing shake and cause lots of noise distractions at all times, making this very inconvenient for anyone involved. We strongly disagree with the proposal and the possibility it could hinder the operations we have worked very hard to maintain over the years.

Thank you.

Zoie Stacey

Executive Assistant

Small & Sons Oil

253-736-6758

zoies@smallandsons.com