Financial Impact of Fuel Conversion on Consumer Owned Utilities and Customers in Washington

Final Report

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Energy+Environmental Economics

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Executive Summary

Study Overview

Greenhouse gas (GHG) emissions from direct use of fossil fuels in buildings currently represent about 10% of Washington's statewide total emissions[1]. In order to achieve Washington's climate target of economy-wide carbon neutrality by 2050, those direct emissions will need to be reduced. The 2021 Washington State Energy Strategy identified that building electrification is a lower-cost strategy to decarbonize Washington's building end-uses compared to maintaining gas use in buildings at levels similar to today.

The Washington State Department of Commerce ("Commerce") retained Energy and Environmental Economics, Inc ("E3") to identify near-term opportunities and challenges for building electrification in Washington, with a specific focus on consumer-owned utilities (COUs). E3 worked with Commerce to recruit four COUs to participate in the study. The four participating COUs include Clark Public Utilities (Clark PUD) and Tacoma Power located to the west of the Cascades, and Richland Energy Services (RES) and Inland Power & Light (IPL) located to the east of the Cascades. These four COUs were selected because they are representative of the diverse set of COUs across the state. They feature different climates, urban and rural settings, and variation in the existing technology mix for heating buildings, among other characteristics. E3 completed an analysis that, for each COU, assesses building electrification cost-effectiveness and the potential system load impacts when building electrification occurs at scale. E3 and Commerce engaged the COUs throughout the study to receive data support and feedback for the analysis and this report.

Approach

In this study, E3 evaluates building electrification via two approaches. The first approach used by E3 is a Benefit Cost Analysis that assesses the cost-effectiveness of building electrification for individual customers from multiple perspectives. The second approach used by E3 is a System Load Impact analysis that assesses the increase in energy sales and peak demand for utilities when building electrification happens over time at scale. Taken together, the two analyses identify key opportunities and challenges related to building electrification in Washington. In identifying those opportunities and challenges, this report informs potential actions that COUs and the state can take to encourage electrification and reduce its impacts on the electric grid.

E3's Benefit Cost Analysis (BCA) approach assesses the marginal costs and benefits of electrifying several representative building segments, including both existing buildings and new construction, in each COU's service area. The BCA was conducted from two perspectives: (1) electric utility customers who electrify (participant), and (2) non-participating electric utility ratepayers (non-participants). E3 developed a BCA Model to evaluate the customer and utility economics of individual technologies

[1] Washington State Greenhouse Gas Emissions Inventory: 1990-2018. https://apps.ecology.wa.gov/publications/documents/2002020.pdf

including electric heat pump heating, ventilation, and air conditioning units (heat pump HVAC) and electric heat pump water heaters (HPWH) in existing buildings. E3 also considered all-electric options for both retrofit buildings and new construction, which, in addition to heat pump HVAC and HPWH, also includes electric cooking and electric clothes drying.

E3's System Load Impact Analysis evaluates potential load impacts on each COU when electrification of heating happens at scales envisioned in the Washington State Energy Strategy. E3 designed seven scenarios for the load impact analysis with varying assumptions about heat pump technologies installed, their performance characteristics and levels of building shell improvement.

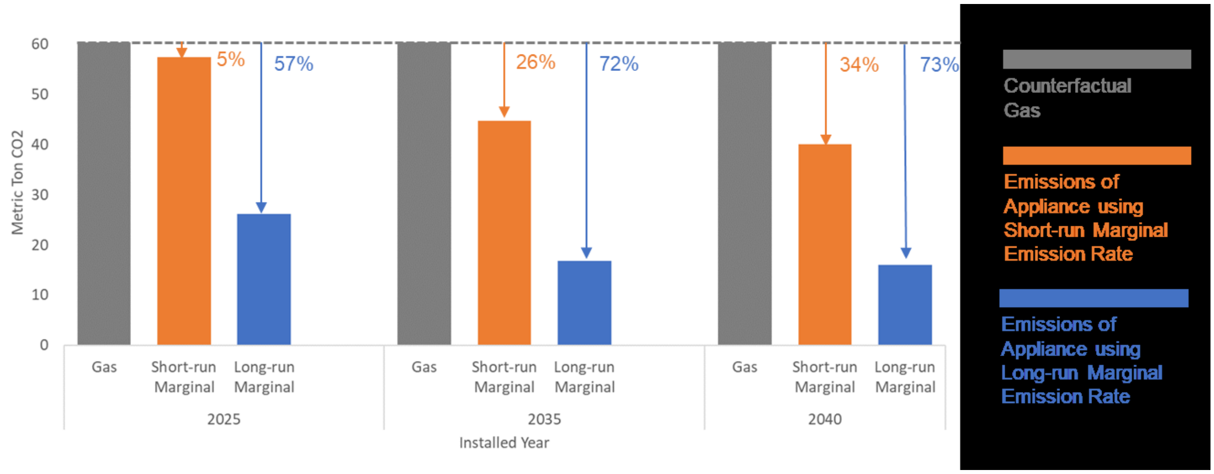
Key Findings

Greenhouse Gas Emissions Savings

E3 found that electrification reduces total greenhouse gas (GHG) emissions across all the building segments and regions studied. For example, a conversion in 2025 from natural gas space heating to an air source heat pump reduces GHG emissions by 5-60% throughout the expected useful lifetime of the equipment (see Figure 0-1 for GHG savings results for a single-family HVAC electrification in RES' service area). The same conversion in 2040 will achieve higher lifetime GHG savings of 34-75% as the Clean Energy Transformation Act (CETA) increases the supply of decarbonized generation serving Washington. The range of GHG savings reflects differences in the timing and magnitude of electric load impact due to climate, building characteristics, occupancy schedules and the use of short-run versus long-run accounting of marginal GHG emissions.

In the short run, because incremental heat pump HVAC loads overlap with existing peak system loads in Washington, the marginal generators that will serve those incremental loads during peak hours are usually natural gas-fired and emit GHGs. However, in the long run, the impact of CETA will result in emissions savings that are consistent with the higher end of the ranges presented above. This report emphasizes GHG savings results using long-run marginal emissions for all modeled building segments because a long-run marginal emissions approach better captures the impacts of CETA on electric sector emissions.

Figure 0-1. Lifetime emissions of a gas furnace vs. a standard heat pump HVAC system in a single-family home in Richland Energy Services' service area.



Near-term building electrification opportunities

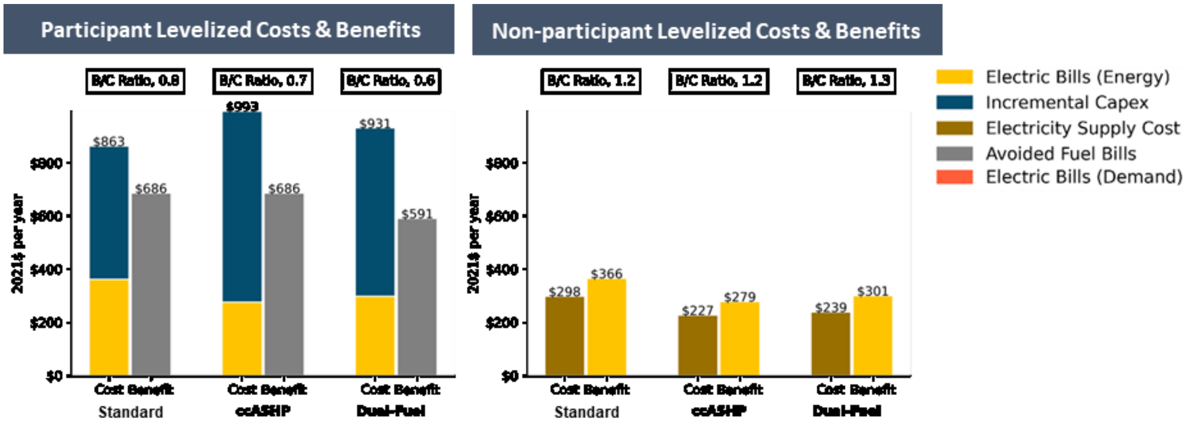
E3 identified several near-term opportunities where electrification can deliver cost savings for COU customers, including:

- **All-electric new construction** offers one of the most promising near-term opportunities for building electrification. Compared to a mixed-fuel new home that needs air conditioning, an all-electric new home saves ~$2,000 in upfront participant costs. Considering both upfront costs and bill savings, all-electric new homes would save ~$1,000 per year over the lifetime of the equipment. Among the segments modeled in this study, all-electric commercial new construction was found to require higher upfront costs, but still generates lifecycle savings for participants due to utility bills savings.
- **Homes that need a new air conditioner (A/C) or a replacement for an existing A/C** represent another savings opportunity when retrofitting from gas-fired space heaters to air source heat pump HVAC systems. Heat pumps provide both heating and cooling, so they avoid the cost of both a furnace and an air conditioner in buildings. Bill savings from switching to heat pumps are higher than the first cost premium for these customers across three of the four COUs studied and thus generate lifetime savings for them.
- **Homes that currently use oil- or liquified petroleum gas-fired (LPG-fired) space heaters** will generate savings when retrofitting to air source heat pump HVAC systems. Delivered fuels such as fuel oil or LPG are more expensive that natural gas when used for heating homes. Lifetime bill savings from space heating alone, when switching from using delivered fuels to electric heat pumps, outweigh the first cost premium and help generate lifetime savings of approximately $60 per year.

- **Retrofits to dual-fuel heat pump HVAC systems** represent savings opportunities for commercial office buildings. Office buildings were found to incur large increases in demand charges by switching to all-electric heat pump HVAC systems. A dual-fuel heat pump HVAC system, which keeps the existing gas heating system and adds a heat pump system, uses the heat pump as the sole source for heating most of the year but switches to the gas back-up system during cold temperatures. By leveraging the existing gas system as a backup heating source, a dual-fuel system helps reduce the otherwise significant increase in peak load and resulting demand charges. E3 found that a dual-fuel system achieves cost parity with a like-for-like replacement of an existing gas system in office buildings while achieving significant GHG savings.
- **Retrofits of healthcare buildings to air source heat pump HVAC systems** represent another savings opportunity among existing commercial buildings. Healthcare buildings oftentimes have very high utilization of their HVAC systems. Therefore, the resulting bill savings from switching to heat pumps are found to be the highest among all studied building types and outweigh the first cost premium in these buildings. However, an important caveat is that this study only models a generic healthcare building. Specific buildings, such as hospitals with emergency rooms, may require backup power, such as a natural gas generator, onsite per federal regulations. Such requirements may result in additional costs, which are not evaluated in this study.
- **Non-participating electric utility ratepayers could see a small benefit from building electrification.** The increase in COU revenues from those who electrify (participants) will be slightly higher than the COUs' costs to serve incremental loads for three of the four COUs. Those revenues could be used to provide incentives to partially overcome the incremental upfront and lifecycle costs associated with electrification (discussed below) without raising rates for non-participants. However, it is important to note that E3 found that incremental revenues earned by the COUs are unlikely to be sufficient to provide incentives that cover the full incremental cost of electrification for participants.
- **Electrification could become cost effective for consumers if gas prices rise.** E3 conducted a sensitivity analysis to estimate the cost of reducing GHG emissions from pipeline gas via the exclusive use of higher cost low-carbon gasses such as hydrogen and renewable natural gas. We found that electrification provides savings relative to exclusive use of low-carbon gas, which consistent with findings from the 2021 Washington State Energy Strategy.

Figure 0-2. Participant and non-participant costs and benefits of HVAC electrification in Clark PUD's service area. Results are for a single-family residential retrofit home installing a heat pump HVAC system replacing

an existing gas furnace. The high incremental first costs are the major barrier for electrification to be cost effective in this case and other retrofit cases.



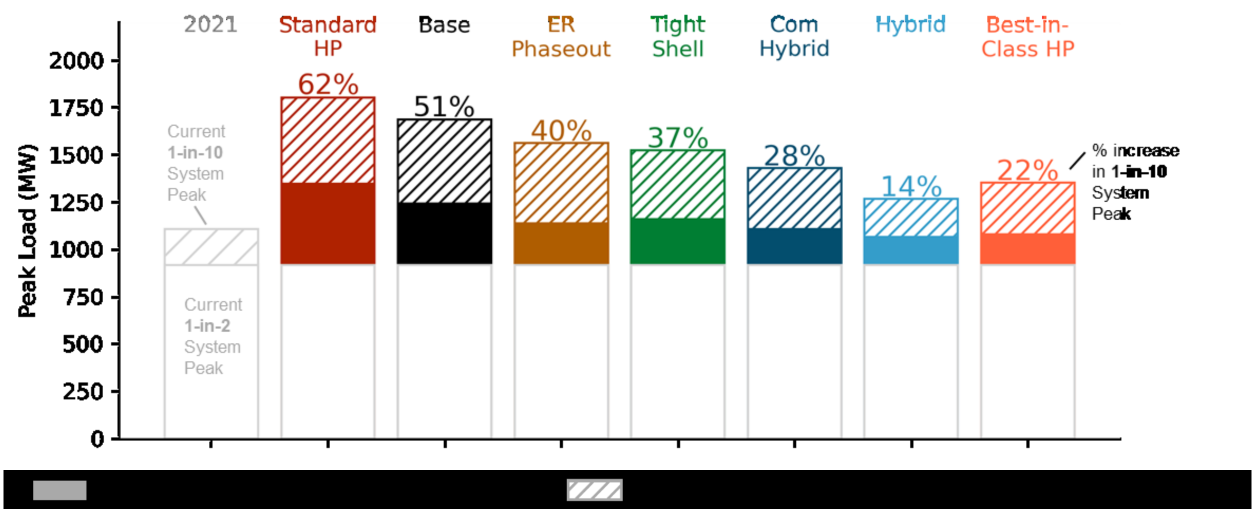
Challenges with building electrification

Although building electrification can be lower cost in several applications today, E3 found challenges for many customers to achieve cost savings, as well as for utilities to manage the load impact from electrification. These challenges include:

- **The high incremental first costs of electrification in retrofit buildings** were found to be a barrier to electrification. The equipment cost of a heat pump HVAC system is higher than a gas heating system. In addition, retrofits from an existing gas-fired heating system to a heat pump HVAC system may require extra work such as additional wiring or service panel upgrades. See Figure 0-2 for participant and non-participant costs and benefits results for single-family HVAC electrification in Clark PUD's service area.
- **Low natural gas rates** make electrification more challenging for customers. The lower bill savings, as a result, create another barrier to electrification for customers, especially those in the RES service area where natural gas rates are lower than other three COUs.
- **Ratepayer funds from electrification will likely NOT be sufficient** to subsize the incremental costs of electrification retrofits, as discussed above. To make electrification cost effective and to incentivize market transformation, other sources of funds are needed in addition to ratepayer funds.
- **Peak load impacts from building electrification will be moderate by 2030 and significant by 2050** at the pace of adoption envisioned in the 2021 Washington State Energy Strategy. E3 found that building electrification increases peak electric load by 3-10% by 2030 and 30-70% by 2050 for the four studied COUs, while annual electricity sales will only increase by ~10% by 2050. Annual electricity sales increases are moderate because heat pump HVAC systems are efficient for heating buildings during mild temperatures that occur over most of the year. However, peak load impacts from building electrification are pronounced in Washington because peak loads from heat pumps occur during coldest hours of a year and are coincident with current system peaks, which are already driven by space heating demands.

- **Intervention measures can reduce the system load impacts from electrification, but some of the measures evaluated may not be cost effective today.** E3's Benefit Cost Analysis results indicates that customers see the most favorable economics if they adopt lower cost heat pumps with moderate levels of performance, rather than cold climate or dual-fuel systems. Electrifying buildings with those lower-cost heat pumps would result in significant increases in electric peak demands for the COUs studied. This study evaluated a variety of intervention measures such as incentivizing best-in-class heat pump models, encouraging building shell improvements, dual-fuel heating systems and replacing electric resistance heating with heat pumps. The intervention measures were found to be effective at reducing peak load increase from electrification by up to 60% for all-electric systems and 85% for dual-fuel systems. Although this study does not evaluate costs of all the intervention measures, the Benefit Cost Analysis suggests that some measures that reduce peak demands may not be cost effective today, such as best-in-class cold-climate heat pump HVAC systems.

Figure 0-3. Peak Load Growth in 2050 by Scenarios Evaluated in this Study, at the Scales Envisioned in the 2020 Washington State Strategy Study. Results are shown for Clark PUD.



Recommendations

This study identifies several near-term opportunities where electrification is cost-effective, but also identifies large segments of the state's existing building stock where electrification comes at a large upfront cost premium. Based on the key findings from our analysis, E3 provides the following recommendations:

1. **Incentivize all-electric new construction.** All-electric new construction is cost-effective in all cases considered in this report.

2. **Target heat pump HVAC at customers that need new air conditioners and those currently relying on fuel oil or propane for heating.** These customers have the lowest costs among the retrofit opportunities considered in this study.
3. **Provide subsidies to lower the incremental consumer costs of electrification.** In cases where utility revenues from additional sales exceed the incremental costs of electrification, incremental consumer costs could be partially funded by ratepayer funds. However, non-ratepayer sources of funding will be needed to make electrification cost-effective for customers without negatively impacting non-participants.
4. **Ensure efficient price signals are conveyed in electric and natural gas rates.** Design more efficient electric rates, including time varying rates, that align prices with system costs. For example, results from this work indicate commercial demand charges shift customer economics towards dual-fuel heat pumps, which at scale would have the lowest impact on the COU's peak demands. More efficient rates could encourage the adoption of higher-efficiency heat pumps and dual-fuel heat pumps that alleviate load impacts from electrification and cost burdens on the electric system. Policies aimed at reducing the GHG emissions from natural gas would also better align customer's economic incentives with the state's climate goals and make electrification more cost effective.
5. **Implement measures to alleviate peak load impact from electrification.** Measures include:
    - **Support market transformation of high-efficiency heat pump models to reduce their cost premiums**. Utilities could subsidize high-efficiency heat pump models to further provide incentives for customer adoption. Utilities should also consider partnering with manufacturers to incentivize research, development and commercialization of high-efficiency cold-climate heat pump products, and push for market transformation to achieve cost reductions via economies of scale.
    - **Target replacement of electric resistance heating with more efficient heat pump HVAC systems.** A complete phase-out of resistance heating is found to reduce peak load impact from electrification by more than 30%, compared to a scenario that is consistent with the 2021 Washington State Energy Strategy.
    - **Incentivize shell improvements for older buildings.** Moderate shell improvements that target improving roof insulation and reducing infiltration could be less cost-prohibiting compared to deep shell retrofits but still effective at reducing system peak loads. Further investigation into costs of shell upgrade would be needed to determine its cost-effectiveness for specific applications.
    - **Leverage demand response (DR) programs to help lower the peak system load and electric bills for commercial customers.** A DR sensitivity conducted in this study found that by expanding the thermostat setpoints of office buildings by 3 °F during the system peak hours, peak heating demand could be lowered by as much as 20% during a typical winter. Further assessment for the technical feasibility and costs of DR programs are needed to determine what is feasible for utilities to implement.
    - **Encourage customers to install dual-fuel heat pump HVAC systems.** The Peak Load Impact Analysis found that installing dual-fuel systems in commercial buildings alone could reduce peak load impact from electrification by more than 50% compared to all-

electric systems. Utilities may design more efficient rates or programs that would align price signals with system costs and savings and make dual-fuel heat pumps cost effective.

6. **Carefully design policies to support the large infrastructure needs for building electrification and potential high capital investments.** Achieving building electrification at the scales envisioned in the Washington State Energy Strategy will require a robust ecosystem, including supply chains and skilled labor. Building a sufficient amount of electric infrastructure will similarly require substantial new construction activities by the state's electric utilities.

1 Introduction

1.1 Study motivation and goals

Greenhouse gas (GHG) emissions from direct use of fossil fuels in buildings currently represent about 10% of Washington's statewide total emissions[2]. To achieve Washington's climate target of economy-wide carbon neutrality by 2050, those emissions need to be reduced. The 2021 Washington State Energy Strategy identified that building electrification is a lower cost strategy to decarbonize Washington's building end-uses compared to maintaining gas use in buildings at levels similar to today. Electrification would support decarbonization as the Clean Energy Transformation Act (CETA) increases the supply of decarbonized generation serving Washington. However, studies have shown there are significant barriers to building electrification today. This study aims to identify near-term opportunities and challenges with building electrification in Washington, with a specific focus on consumer-owned utilities (COUs).

The Washington State Department of Commerce ("Commerce") retained Energy and Environmental Economics, Inc. ("E3") to identify near-term opportunities and challenges for building electrification in Washington, with a specific focus on consumer-owned utilities (COUs). E3 worked with Commerce to recruit four COUs to participate in the study. The four participating COUs include Clark Public Utilities (Clark PUD), Tacoma Power, Richland Energy Services (RES), and Inland Power & Light (IPL). These four COUs were selected because they are representative of the diverse set of COUs across the state. They feature different climates, both urban and rural settings, and variation in the existing technology mix for heating buildings, among other characteristics. E3 completed an analysis that, for each COU, assesses building electrification cost-effectiveness and the potential system load impacts when building electrification occurs at scale. E3 and Commerce engaged the COUs throughout the study to receive data support and feedback for the analysis and this report.

The key goal of this study is to identify opportunities and challenges with building electrification in Washington. Elements of this study include:

- An assessment of marginal building electrification cost-effectiveness for several representative buildings in Washington
- An estimate of potential system load impacts from building electrification on selected Consumer-Owned Utilities in Washington
- An identification of priority actions and market segments for future utility or government programs to encourage building electrification in Washington

[2] Washington State Greenhouse Gas Emissions Inventory: 1990-2018. https://apps.ecology.wa.gov/publications/documents/2002020.pdf

1.2 Report contents

The remainder of the report is organized as follows:

- Chapter 2 presents the Benefit Cost Analysis, including methodology, key assumptions and results of the analysis
- Chapter 3 presents the Peak Load Impact Analysis, including methodology, scenario design and results of the analysis
- Chapter 4 concludes with discussion of the key findings and recommendations

Additionally, several appendices with additional technical details are included

- Appendix 5.1: Building Simulation Descriptions
- Appendix 5.2: Building Stock Characterization
- Appendix 5.3: Technology Specifications
- Appendix 5.4: Additional Benefit Cost Analysis Results
- Appendix 5.5: RESHAPE Modeling Assumptions
- Appendix 5.6: Additional Scenarios Modeled
- Appendix 5.7: Additional Peak Load Impact Results

2 Benefit Cost Analysis

2.1 Introduction

E3's Benefit Cost Analysis (BCA) approach assesses the marginal costs and benefits of electrifying several representative building segments, including both existing buildings and new construction, in each COU's service area. The BCA was conducted from two perspectives: (1) electric utility customers who electrify (participant), and (2) non-participating electric utility ratepayers (non-participants). E3 developed a BCA Model to evaluate the customer and utility economics of individual technologies including electric heat pump heating, ventilation, and air conditioning units (heat pump HVAC) and electric heat pump water heaters (HPWH) in existing buildings. E3 also considered all-electric packages, including clothes drying and cooking, for both retrofit buildings and new construction.

The BCA aims to evaluate the consumer economics of building electrification in Washington. In addition, by comparing the economics of electrification for participating utility customers and non-participating utility ratepayers, the BCA also aims to evaluate whether the consumer-owned utilities (COUs) could use ratepayer funds to subsidize building electrification.

2.2 Modeling Approach

2.2.1 Benefit Cost Analysis Cost Tests

This study considers the costs and benefits of building electrification in Washington State through two cost test methodologies:

- The **Participant Cost Test** (PCT) assesses whether electrification is cost-effective for electric utility customers who adopt electrification measures. It compares the cost of electrification measures against expected bill savings over the lifetime of the replacement equipment.
- The **Ratepayer Impact Measure** (RIM) assesses whether the benefits of electrification outweigh the costs for electric utility customers who do not adopt electrification measures. The RIM test reflects whether electric utilities can recover costs from participants to serve additional loads from electrification and fuel switching.

These two tests were chosen because they identify the financial impacts of building electrification on COUs and their customers. When the RIM test is positive, this means that a COU would receive more revenue from an electrified customer than it would cost to serve them. A portion of that incremental revenue could therefore be used to provide incentives to promote electrification without increasing costs for non-participants or to reduce rates for all COU ratepayers. A summary of the input assumptions for the cost tests can be found in Table 2-1.

E3 developed a Benefit Cost Analysis Model to evaluate the customer and utility economics of heat pump HVAC and HPWH in existing buildings and all-electric retrofits which include electric stoves and electric clothes dryers in addition to heat pump HVAC and HPWH. Each of these electric technologies are compared to an alternative that uses natural gas or delivered fuels like propane or fuel oil. In addition, all-electric new construction is evaluated relative to a mixed-fuel alternative where the heating appliances described above are fueled by natural gas.

E3 assumed lifetimes of 18 years, 13 years, and 13 years for HVAC, water heating, and other appliances respectively. Lifetime costs and benefits were calculated assuming nominal discount and inflation rates as summarized in the table below. The cost of adopting electrification measures included panel upgrades where necessary and the benefit of avoided gas connections in new construction.

Table 2-1 Summary of Cost Tests

Rate Type	PCT	RIM
Assumed Discount Rate (real)	7.0%	3.0%
Incremental Capex (Equipment & Installation)	Cost	-
Avoided Fuel Bills (Fuel & Delivery)	Benefit	-
Electricity Bills (Energy & Demand)	Cost	Benefit
Electricity Supply Costs	-	Cost

2.2.2 Greenhouse Gas Emissions

A key metric assessed in this study is the greenhouse gas (GHG) emissions impact from building electrification. E3 evaluated two different views on marginal electric grid emissions – short-run marginal emissions and long-run marginal emissions. Short-run marginal emissions reflect the immediate increase in emissions to serve additional load from the marginal generator in the near term. In the short run, because incremental heat pump HVAC loads overlap with existing peak system loads in Washington, the marginal generators that will serve those incremental loads during peak hours are usually natural gas-fired and emit GHGs. Therefore, using short-run marginal emissions provides a lower-bound estimate for GHG savings. Long-run marginal emissions account for the fact that additional load will be served by an increasing percent of renewable energy as the grid becomes carbon-free by 2045 under the Clean Energy Transformation Act (CETA). Therefore, long-run marginal emissions offer a more optimistic view of emissions savings.

The two types of marginal electricity emissions are calculated using different methods. Short-run marginal emissions were calculated from E3's market price forecast for the Pacific Northwest developed in the proprietary modeling software Aurora[3]. That same market price forecast is also used to determine the energy costs of meeting incremental loads from electrification in this study (see details in 2.1.7). E3 applies an implied heat rate methodology to the market price forecast to determine whether the marginal unit on the system at each hour is a gas-fired generator or a non-emitting generator such as renewables. The hourly short-run marginal emissions are either zero if a non-emitting generator is on the margin or calculated using the implied heat rates when a gas-fired generator is on the margin. Long-run marginal emissions are from the latest version of the National Renewable Energy Laboratory (NREL) Cambium data sets that modeled future electricity resource expansion and dispatch for Washington under CETA[4]. Figure 2-1 shows that annual long-run marginal emissions are consistently lower than short-run marginal emissions and the differences become larger over time.

This report emphasizes GHG savings results using long-run marginal emissions for all modeled building segments because long-run marginal emissions capture the impacts of CETA on electric sector emissions.

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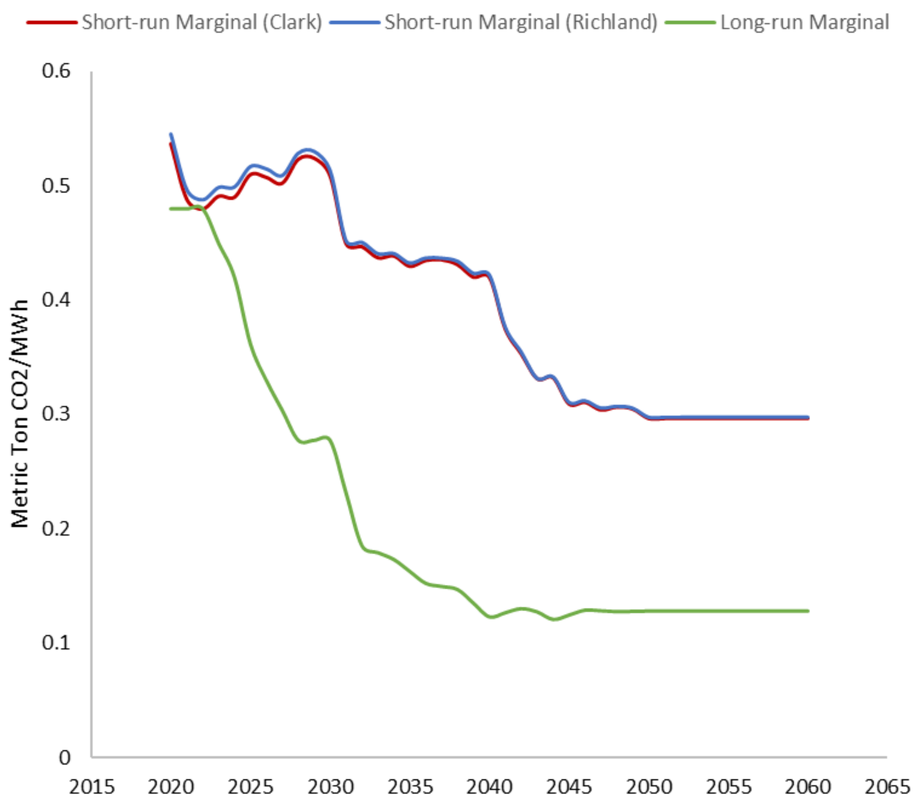
[3] AURORA is a proprietary model E3 licensed from Energy Exemplar. https://www.energyexemplar.com/aurora
[4] Cambium Documentation: Version 2021. https://www.nrel.gov/docs/fy22osti/81611.pdf

Figure 2-1. Comparison of annual energy sales-weighted short-run marginal greenhouse gas emissions (showing Clark PUD and Richland as examples) from upstream electricity generation versus annual long-run marginal emissions (same across COUs)



2.2.3 Selected Consumer-Owned Utilities

E3 worked with the Washington Department of Commerce to identify four Consumer-Owned Utilities (COUs) with broad representation for the state overall. Selection criteria included geography (in part to account for a range of local climates), rural or urban settings, and the existing stock share of space heating equipment by fuel type as summarized in the table below. Stock shares were estimated through a combination of publicly available data from the EIA Residential Energy Consumption Survey, the Residential Building Stock Assessment, and feedback provided by the COUs. Key characteristics of the selected COUs can be found in Table 2-2.

Table 2-2 Summary of Key Criteria for Utility Selection

Criteria	Tacoma	Clark	Inland	Richland
Utility Type	Municipal	Public	Cooperative	Municipal
East/West of Cascades	West	West	East	East
Urban/Rural	Urban	Rural	Urban/Rural	Rural
Electricity Share of Heating	~57%	~60%	~70%	~64%
Gas Share of Heating	~37%	~36%	~1%	~22%

Delivered Fuel Share of Heating	~2%	~1%	~15%	~19%
BPA Requirements	Partial	Partial	Full	Full

2.2.4 Representative Buildings

E3 identified seven residential building segments and seven commercial building segments as representative buildings to model in this study. This section describes the building stock analysis conducted to identify the representative building segments and the characteristics of the fourteen building segments.

2.2.4.1 Building Stock Analysis

E3 conducted an analysis of residential and commercial building stock in the study geography based on publicly available data from the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS)[5] and Commercial Building Energy Consumption Survey (CBECS).[6] RECS and CBECS provide data on residential and commercial site characteristics across the United States, including total annual energy consumption, energy consumption by end use (e.g. space heating), and the types of equipment and fuels in use at each site. Residential results from RECS were cross-checked against the most recent Residential Building Stock Assessment (RBSA) from Northwest Energy Efficiency Alliance.[7]

To generate datasets of observations representative of the study geography, available residential and commercial observations were filtered according to International Energy Conservation Code (IECC) or the U.S. Department of Energy Building America (BA) climate zone, census division, state or state cluster, and space heating fuel type (natural gas or delivered fuel such as propane and fuel oil).

Residential building observations were classified according to IECC climate zone, building type (single- or multi-family), space heating fuel, and the presence or absence of air conditioning; E3 determined these characteristics to be primary drivers of capital costs associated with electrification based on previous work. Similarly, CBECS observations were classified according to BA climate zone, existing air conditioning equipment, primary building use, and space heating fuel.

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[5] "2009 RECS Survey Data", Energy Information Administration, 2009, https://www.eia.gov/consumption/residential/data/2009/index.php?view=microdata.

[6] "2012 CBECS Survey Data", Energy Information Administration, 2012, https://www.eia.gov/consumption/commercial/data/2012/.

[7] "Residential Building Stock Assessment ii Combined Database", Northwest Energy Efficiency Alliance, 2018, https://neea.org/resources/rbsa-ii-combined-database.

Median building size and energy consumption values were calculated for each building type and weighted according to EIA-provided sample weights from each database. E3 selected building types for further modeling in order to maximize representation of the statewide building stock by number of households (for residential) or building square footage (for commercial) and energy consumption. A list of final building types and their equipment and energy characteristics is included in Appendix 5.1.

2.2.4.2 Building Types Modeled

E3 selected seven residential and seven commercial building models for energy simulation modeling in OpenStudio EnergyPlus[8] based on the statewide building stock characterization described in Section 2.1.2, representing five building distinct building types as shown in Figure 2-2 with different sizes, building uses, climate zones, and incumbent equipment characteristics. Table 2-3 and Table 2-4 show the fourteen buildings selected in this study. A detailed description of selection criteria and building characteristics are in Appendix 5.2.

Figure 2-2. Five Building Types Modeled in this Study and Their Characteristics

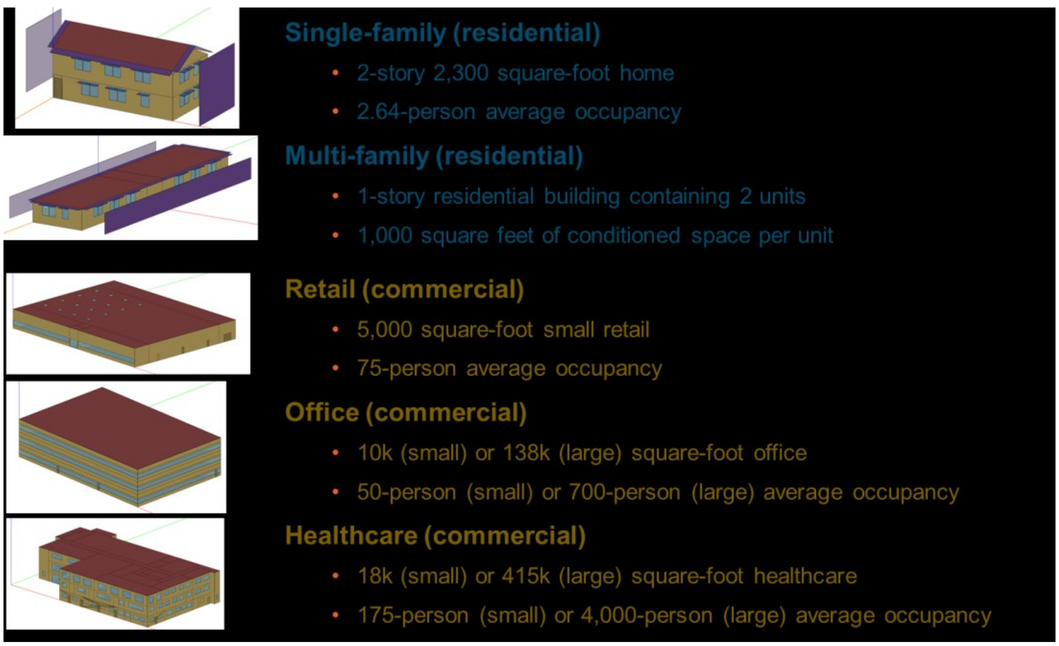


Table 2-3. Residential Representative Building Models Selected in this Study

No	IECC Climate Zone	Building Type	Space Heating Fuel	A/C
1	4C	Single Family	Gas	A/C
2	5B-5C	Single Family	Gas	A/C
3	4C	Single Family	Gas	No A/C
4	4C	Single Family	Delivered Fuel	No A/C

[8] OpenStudio 3.3, National Renewable Energy Laboratory, 2021, https://openstudio.net/

5	4C	Single Family	Delivered Fuel	A/C
6	5B-5C	Single Family	Gas	No A/C
7	5B-5C	Multifamily	Gas	A/C

Table 2-4. Commercial Representative Building Models Selected in this Study

No	BA Climate	HVAC Equipment	Primary Use
1	Cold	Packaged Unit	Retail
2	Marine	Packaged Unit	Retail
3	Marine	Packaged Unit	Office
4	Marine	Boiler/Chiller	Office
5	Cold	Packaged Unit	Office
6	Marine	Boiler/Chiller	Healthcare
7	Cold	Packaged Unit	Healthcare

To develop representative end-use energy use profiles for each building type, E3 adapted prototype models from NREL ResStock for residential buildings[9] and US Department of Energy reference building prototypes for commercial buildings.[10] E3 created customized retrofit and new construction variations of each prototype model using building envelope characteristics updated to reflect the latest Washington State building codes. Each simulation generated end use profiles for HVAC, water heating, and cooking and clothes drying. Details of building simulation and prototype building models are in Appendix 5.1

Local climate characteristics and temperature profiles are a key driver of building energy use. EnergyPlus simulations were run using typical meteorological year (TMY) climate files for climate zones 4B and 5C as required for each building type. Although TMY files do not cover extreme weather events, they can provide insight into system performance for typical weather conditions. In addition, TMY climate files are the current industry standard for energy simulation and system selection conducted by engineers and energy modelers in the building industry. Therefore, the simulations conducted for this analysis are in alignment with the methods that would be taken by actual building engineers for system sizing and modeling. Where necessary, E3 scaled the resulting end use profiles in order to align annual consumption with primary data from the building stock analysis. The impact of extreme weather events is evaluated in Chapter 3 System Load Impact Analysis.

2.2.5 End Use Technologies, First Costs and Efficiencies

E3 modeled equipment CAPEX and OPEX costs and lifetime electric and gas bill impacts of electrification measures using our in-house Building Electrification (BE) Tool. The BE Tool takes three major inputs for each building prototype:

[9] "ResStock Analysis Tool", National Renewable Energy Laboratory, 2021, https://www.nrel.gov/buildings/resstock.html

[10] "Commercial Reference Buildings", US Department of Energy Office of Energy Efficiency & Renewable Energy, 2021, https://www.energy.gov/eere/buildings/commercial-reference-buildings

1. Site characteristics (e.g. building size and load) derived from the building stock characterization in Section 2.1.2
2. Technology mix derived from the building stock characterization (Section 2.1.2)
3. End-use energy profiles from EnergyPlus simulations (Section 2.1.2.2)

The BE tool models the appropriate replacement system size and resulting combined energy profiles of electrification measures. It then uses equipment rated efficiencies and associated efficiency curves to calculate input energy required from the grid on an hourly basis, resulting electric and gas bill impacts, and CAPEX and OPEX for each building type.

2.2.5.1 HVAC

Heating, ventilation and air conditioning (HVAC) accounts for more than half of the annual energy usage of a typical residential home in the United States.[11] Electrification measures that replace gas furnaces and electric resistance heating with highly efficient air source heat pumps therefore have the potential to significantly reduce household energy usage while also lowering GHG emissions from the buildings sector.

This study models three types of heat pumps: (1) a standard regular air-source heat pump (Standard HP) uses electric resistance backup in coldest hours, (2) a cold-climate air-source heat pump (Cold Climate HP) retains high efficiency even at cold temperatures, and (3) a dual-fuel heat pump ("Dual-fuel" HP) pairs a standard HP with a gas furnace as a backup heat source in coldest hours. Achieved efficiencies assumed for space heating and space cooling across residential and commercial buildings are summarized in Table 2-5.

E3's modeling of all-electric heat pump HVAC systems does not assume a lock-out of compressor even at low temperatures. Electric resistance is assumed to be supplemental to the compressor when operating at low temperatures. However, E3's modeling of dual-fuel heat pump systems assumes a lock-out of compressor when gas furnace operates at low temperatures.

Table 2-5 HVAC Equipment Types Modeled and Achieved Annual Average Efficiencies

Scenario	HVAC Equipment	Achieved Efficiency	
		Clark PUD and Tacoma Power (Climate Zone 4C)	RES and IPL (Climate Zone 5C-5B)
Mixed-Fuel	**Gas Furnace (residential) Or Boiler (commercial)**	80%	80%
	Central A/C (residential) Or Chiller (large commercial)	COP – 4.1	COP – 4.1
Electrification	**Standard HP**	COP – 2.4	COP – 2.0
	Cold Climate HP	COP – 2.8	COP – 2.6
	"Dual-fuel" HP	COP – 3.8 for HP	COP – 3.2 for HP

[11] Energy Information Administration, 2021, "Use of energy explained: energy use in homes", https://www.eia.gov/energyexplained/use-of-energy/homes.php

	80% for gas backup	80% for gas backup

2.2.5.2 Domestic Hot Water

Water heating accounts for 15-25% of annual energy use in a typical residential home, making it the second largest end use after space heating and cooling. Similar to air source heat pumps, heat pump water heaters are much more efficient than either electric or gas alternatives and can generate savings for homeowners. E3 considered three types of water heating equipment including gas storage water heaters for retrofit application, gas tankless water heaters for new construction and heat pump storage water heaters for the electrified option. Water heating equipment types and efficiencies modeled are summarized in Table 2-6.

Table 2-6. Water Heating Equipment Types Modeled and Efficiencies

Scenario	HVAC Equipment	Efficiency
Mixed-Fuel	**Gas Storage (retrofit application)**	0.62 UEF
	Gas Tankless (new construction)	0.75 UEF
Electrification	**Heat Pump Storage**	4.00 UEF

2.2.5.3 All-electric End Uses

In addition to heat pump HVAC and heat pump water heaters, this study also modeled all-electric retrofits and new construction which include electric stoves and electric clothes dryers in addition to heat pump HVAC and HPWH.

Cooking and clothes drying appliances are the largest source of “other” energy usage in a residential home. This study considered electric and gas cooktops, as well as electric and gas clothes dryers. The efficiencies for cooking and clothes drying equipment considered in this study are summarized below. Cooking and clothes drying equipment types and efficiencies are summarized in Table 2-7.

Table 2-7 Cooking and Clothes Drying Equipment Types and Efficiencies

Equipment Type	Efficiency
Electric Cooktop	0.74
Gas Cooktop	0.40
Electric Dryer	0.71
Gas Dryer	0.62

2.2.6 Customer Costs and Savings

E3 separated equipment installation costs into capital and labor costs, and validated by comparison to empirical data on heat pump installations from the region. Devices installed as part of retrofits are assumed to be installed at the end of the existing device's life. For HVAC and water heating, retrofit costs are considered as incremental costs relative to a "like-for-like" replacement in which a new device of the existing type is installed but the customer does not adopt an air source heat pump or heat pump water heater.

Heat pump HVAC systems provide both heating and cooling services. This means that heat pump can replace both a furnace and a central air conditioner for buildings that have both heating and cooling. In this analysis, E3 assesses the consumer costs of heat pump HVAC assuming that the electrification measure is applied upon furnace burnout in retrofit buildings. At the time of furnace burnout the building's central air conditioning system may not have reached the end of its useful life. Given that, E3 assumes in our central case that only 50% of the air conditioning cost can be considered avoided when installing a heat pump HVAC system as shown by the hollow gold bar in Figure 2-3. E3 also assessed sensitivities where 100% of the air conditioning cost can be considered avoided and where 0% can be considered avoided.

E3's modeling of water heating electrification in retrofit buildings considers a heat pump water heater that more than doubles the counterfactual cost of a "like-for-like" replacement of gas storage water heater, as shown in Figure 2-4.

All-electric new construction is found to be less expensive than mixed-fuel new construction, as shown in Figure 2-5.

Figure 2-3 Example HVAC install costs for single family residential home (retrofit, $2021)

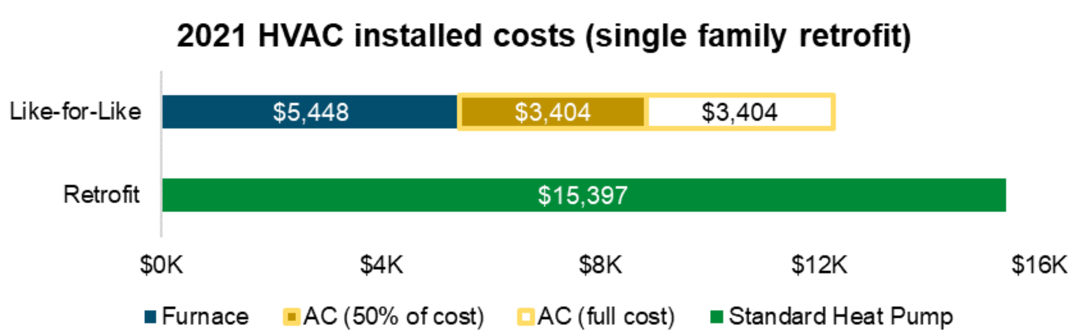
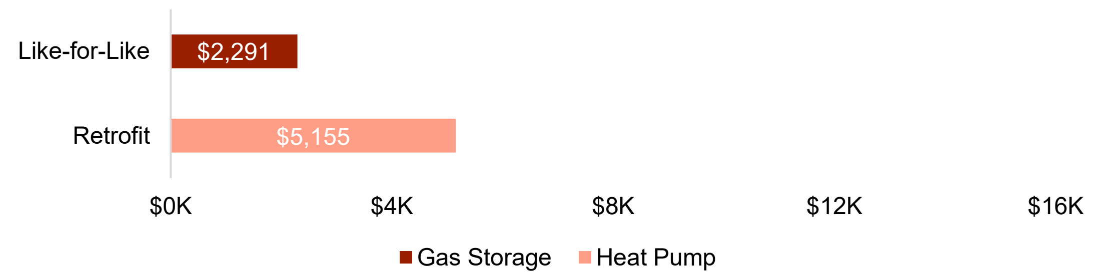
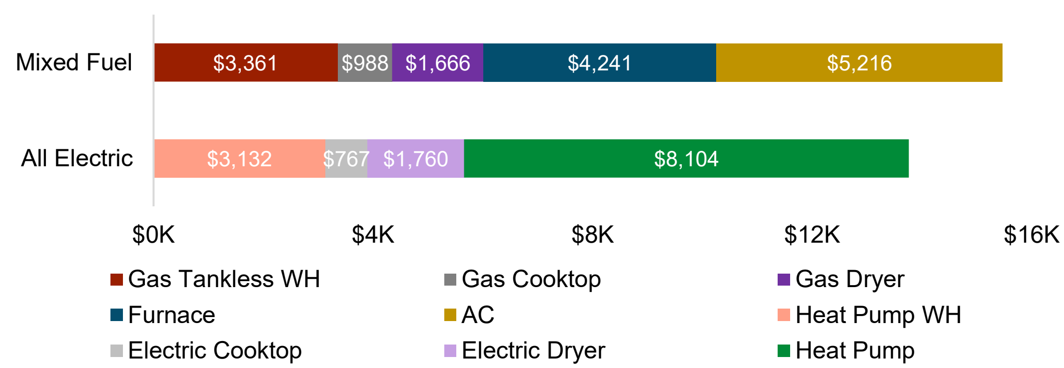


Figure 2-4 Example Water Heating install costs for a single family residential home (retrofit, $2021)



Capital costs were drawn from a combination of four sources: E3's previous work[12] (residential HVAC and water heating), the Energy Information Administration [13] (Commercial HVAC and water heating, commercial appliances), and the Northwest Planning and Conservation Council (residential appliances).[14] E3 applied cost reductions over time for each technology type according to learning rates informed by NREL's Electrification Futures Study – note that these rates do not take into account future policies, such as subsidy programs, that may further reduce customer costs. E3 drew on labor costs from the studies referenced above and adjusted them for Northwest labor using the latest available data for the region from RSMeans.

Figure 2-5 Example whole-home capital costs for a single family residential home (new construction, $2021)



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[12] Energy and Environmental Economics, 2019, "Residential Building Electrification in California", https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

[13] Energy Information Administration, 2018, "National Energy Modeling System: An Overview."

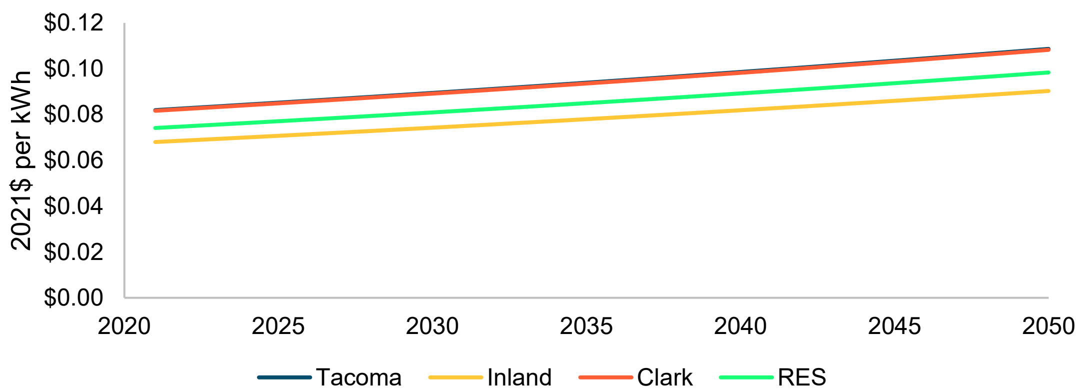
[14] NW Power Planning & Conservation Council Regional Technical Forum, "UES Measure Library"

Gas connection costs in new construction buildings are assumed to be $2,435 per building. This is the average cost of residential line extension, based on filings by Avista Corporation, a utility that provides gas services to customers of Inland.[15] Gas connection costs for other gas utilities are not publicly available and are assumed to be the same as Avista. Avista and Cascade Natural Gas Corporation, the gas utility serves the City of Richland, each provides a line extension allowance of $4,678 and $3,275[16] for existing residential homes that are converting to natural gas.

2.2.6.1 Electricity and Natural Gas Retail Rates: Current and Future Rate Assumptions

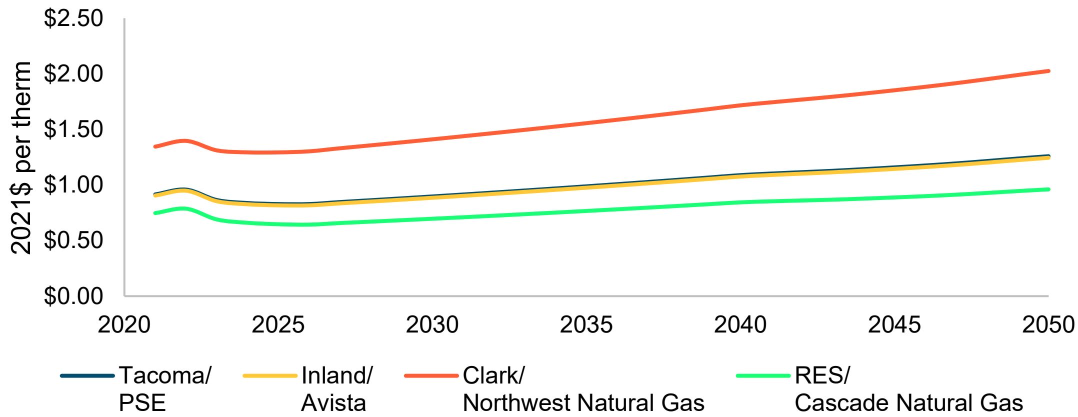
E3 used the latest available electric and gas rate schedules from the COUs considered at the time of the analysis. Electric rates were escalated at 1% annually in real terms, based on a 20-year historical trend of average electric retail rates in Washington State sourced from EIA. COU electric rates are assumed to be flat and without tiers. Rates for large commercial customers include demand charges. Electric and gas rates are show in Figure 2-6 and Figure 2-7, respectively.

Figure 2-6 Residential Electric Rates ($2021/kWh)



[15] Avista Corporation, 2018, "For an Order Authorizing Approval of Changes to the Company's Natural Gas Line Extension Tariff and Associated Accounting and Ratemaking Treatment," p. 6.
[16] Cascade Natural Gas Corporation, 2018, Filing UG – 180673. UTC Case Docket Document Sets | UTC (wa.gov)

Figure 2-7 Residential Gas Rates ($2021/therm)

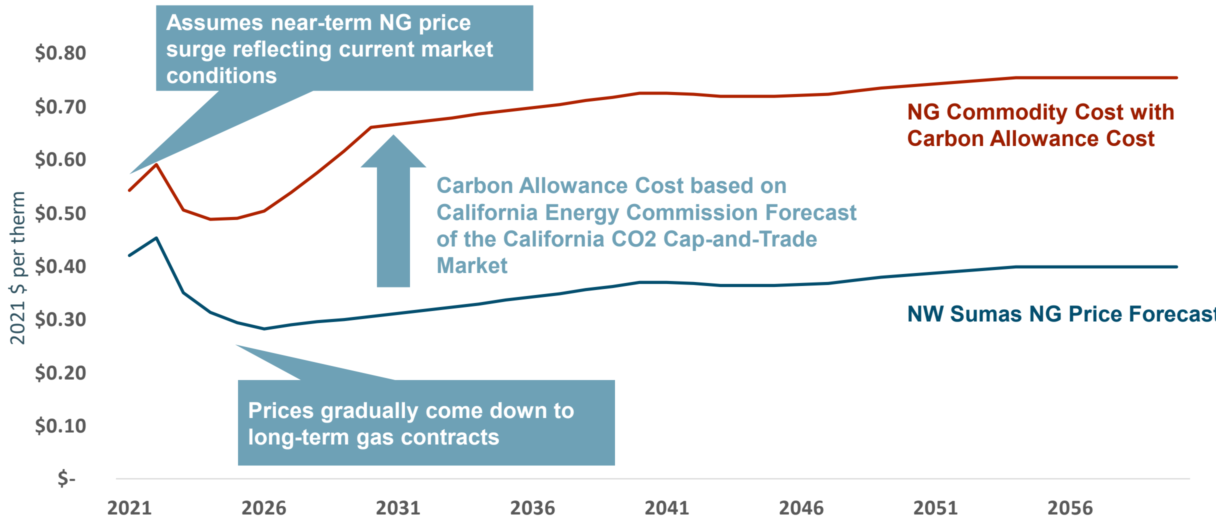


- **Gas Commodity Price Forecast**. Near-term (2022-2026) gas commodity price forecasts were based on NYMAX natural gas futures contract price for the NWP Sumas hub accessed on the S&P Global platform. Long-term (2040-2050) prices are based on the EIA forecast of Henry Hub gas prices, scaled to the Northwest based on historical price differentials between the two hubs. Medium-term (2027-2039) prices were linearly interpolated from the near- and long-term forecasts.
- **Carbon Allowance Cost Adder**. Carbon allowance cost adders were based on the California Energy Commission forecast for the California CO2 cap-and-trade market[17]. This forecast is used as a proxy for the price of GHG allowances that may emerge with the implementation of the Climate Commitment Act of 2021.
- **Gas Delivery Rate and Escalation**. Gas delivery rates were escalated at 2% annually in real terms, based on the 20-year historical trend of average gas retail rates in Washington State sourced from EIA.

Figure 2-8 shows natural gas commodity cost forecast with the Carbon Allowance Cost Adder.

[17] California Greenhouse Gas Allowance price projections for the *2019 IEPR* common scenarios by the California Energy Commission. https://efiling.energy.ca.gov/GetDocument.aspx?tn=227328&DocumentContentId=58424

Figure 2-8 Natural Gas Commodity Cost Forecasts - Base Case



2.2.7 Electric Supply Costs

Marginal electric supply costs represent the costs for utilities to serve incremental load from electrification and are key to the RIM cost test. Electric supply costs used in this study consist of three cost components: energy cost, generation capacity and transmission & distribution (T&D) capacity.

- **Energy cost** is the cost associated with the amount of energy utilities need to generate or purchase to serve incremental loads. This study uses market purchases to represent the marginal source of energy to serve the incremental load for all COUs. This assumption applies to Clark PUD and Tacoma Power because those two COUs only contract partial load with BPA and purchase energy directly from the market for any incremental load. This assumption also applies to RES and IPL even though they fully contract their load with BPA. Incremental loads those two COUs serve are charged by BPA with the Tier-2 rate. The Tier-2 BPA rate is generally similar to market electricity price as BPA goes to the market to purchase energy on behalf of the utilities most of the time. E3 models future market price using the AURORA model. Market prices for the Pacific Northwest are used in this study, consisting of Washington, Oregon, Northern Idaho and Western Montana. The price forecast used in this study is based on a scenario where all current state and local electricity policies are applied including CETA and there is significant electrification that causes load growth.
- **Generation capacity cost** is the cost associated with building or contracting additional firm generation resources to meet the incremental peak loads from electrification and ensure the reliability of the system. This study assumes a long-run capacity cost based on the net cost of new entry (CONE) of a greenfield hydrogen-ready gas CT at $88/kW-yr. E3 applied a Peak Capacity Allocation (PCAF) methodology to convert the annual capacity cost into hourly costs. Hourly costs represent the expected increase in generation capacity cost as load increases in a particular hour. The PCAF methodology achieves the conversion by allocating the annual generating capacity cost to top 500 hours of the year weighted by the magnitude of load in each

of those hours. The hourly loads used for determining the top 500 load hours from the Aurora model for the entire Pacific Northwest zone, net of renewable and hydro generation.

- **Transmission & distribution (T&D) capacity cost** is the cost associated with building or maintaining transmission lines, substations, distribution lines and local transformers to meet the incremental peak loads from electrification. This study uses a near-term incremental T&D cost of $11/kW-yr based on the deferred T&D capacity cost from the Northwest Power and Conservation Council (NWPCC) 8th Power Plan. The near-term values reflect that fact most COUs in Washington have headroom on their systems. The near-term T&D cost is ramped up to a long-run T&D cost of $84/kW-yr by 2030 to reflect the cost of new infrastructure investments under the assumption that when electrification occurs at scale the current headroom on the system will be exceeded and distribution costs will increase. Like the generating capacity cost, the annual T&D costs are allocated to top 500 load hours using the PCAF methodology. Hourly COU-specific system loads are used for the T&D cost allocation for each COU individually.

2.3 Key Results

2.3.1 GHG Emissions Results

Across the state of Washington, building electrification reduces lifetime GHG emissions compared to counterfactual natural gas and other fuel systems. However, the magnitude of GHG emission reduction varies greatly depending on which marginal grid emission rates are applied. The two types of marginal grid emission rates evaluated in this study are short-run marginal emissions and long-run marginal emissions, as described in Chapter 2.2.2.

As highlighted Figure 2-9, for a single-family residential retrofit in 2025 in Richland or Inland service territories, a standard ASHP installation generates only 5% lifetime short-run marginal emissions reduction compared to a gas furnace + AC unit installation. However, when the increased percentage of renewable generators is incorporated, HVAC electrification achieves a lifetime long-run marginal emissions reduction of 57%. By 2035, the lifetime long-run marginal emissions reduction gets as high as 72%. In Clark and Tacoma service territories, building electrification achieves even higher GHG emission reductions, because these COUs operate in a milder climate which allows heat pumps to operate even more efficiently. Table 2-8 shows results for all COUs.

For the purposes of this study, all GHG emissions results in the following sections are presented as lifetime long-run marginal emission reduction. E3 chose this metric for this study as it is more reflective of expected future electric system conditions in the Northwest.

Figure 2-9. GHG Emission Reduction for Single-Family Residential HVAC Electrification, RES

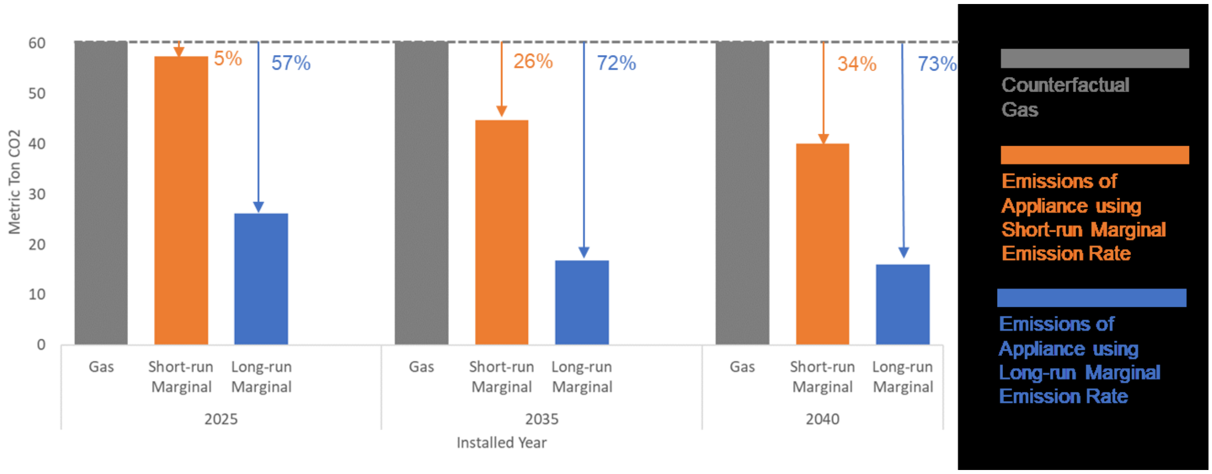


Table 2-8. Long-Run GHG Emission Reduction for Single-Family Residential HVAC Electrification, 2025 Installation

HP Technology	COU			
	Richland	Inland	Tacoma	Clark
Standard ASHP	57%	57%	61%	61%
ccASHP	66%	66%	70%	70%
Dual-Fuel ASHP	41%	41%	54%	54%

2.3.2 Residential Sector Benefit Cost Results

2.3.2.1 Summary of Residential Results

E3's evaluation of the economics of electrification for different residential use cases shows that there are significant economic barriers to electrifying the existing residential building stock in Washington state. For single-family and multifamily residential gas customers across all of the COU service territories within this study, electrification of HVAC and water heating systems is not currently cost-effective for participants who own or occupy existing buildings. This is a result of high capital costs associated with electrification retrofits, and in some cases low gas rates and need for electric panel upgrades. Even with decreasing capital costs of heat pumps and increasing gas bill savings over time, HVAC and water heater electrification is still not cost-effective in 2035 relative to natural gas in most COU service territories. However, E3 conducted a sensitivity analysis that considers the economics of electrification relative to decarbonized gasses and found that HVAC electrification can become cost-effective for single-family retrofit customers relative to decarbonized gas.

With that said, there are some near-term opportunities for electrification that exist within the residential sector of Washington state. Firstly, HVAC electrification is most economically feasible for gas customers who need to replace their furnace and A/C unit at the same time. This reduces the incremental first cost of a heat pump HVAC installation. Additionally, residential customers who are not connected to the gas network and are served by fuels like propane or fuel oil see a net benefit from electrification in every COU service territory. Those fuels are costlier than natural gas which creates larger fuel savings for electrification. Finally, electrification of residential new construction is cost-effective across the state, mainly due to lower upfront costs and the potential to avoid the cost of new gas connections.

As opposed to residential participants, COU ratepayers (also called non-participants) see a small benefit from most residential electrification. This is because the incremental COU revenues due to building electrification from electric bills typically outweigh incremental electricity supply costs. For all-electric new construction, improved building shells lead to lower annual sales and peak demands compared to retrofits, meaning leading to lower electric system cost impacts.

Table 2-9 shows a summary of residential BCA results.

Table 2-9. Residential Benefit Cost Analysis Results Summary

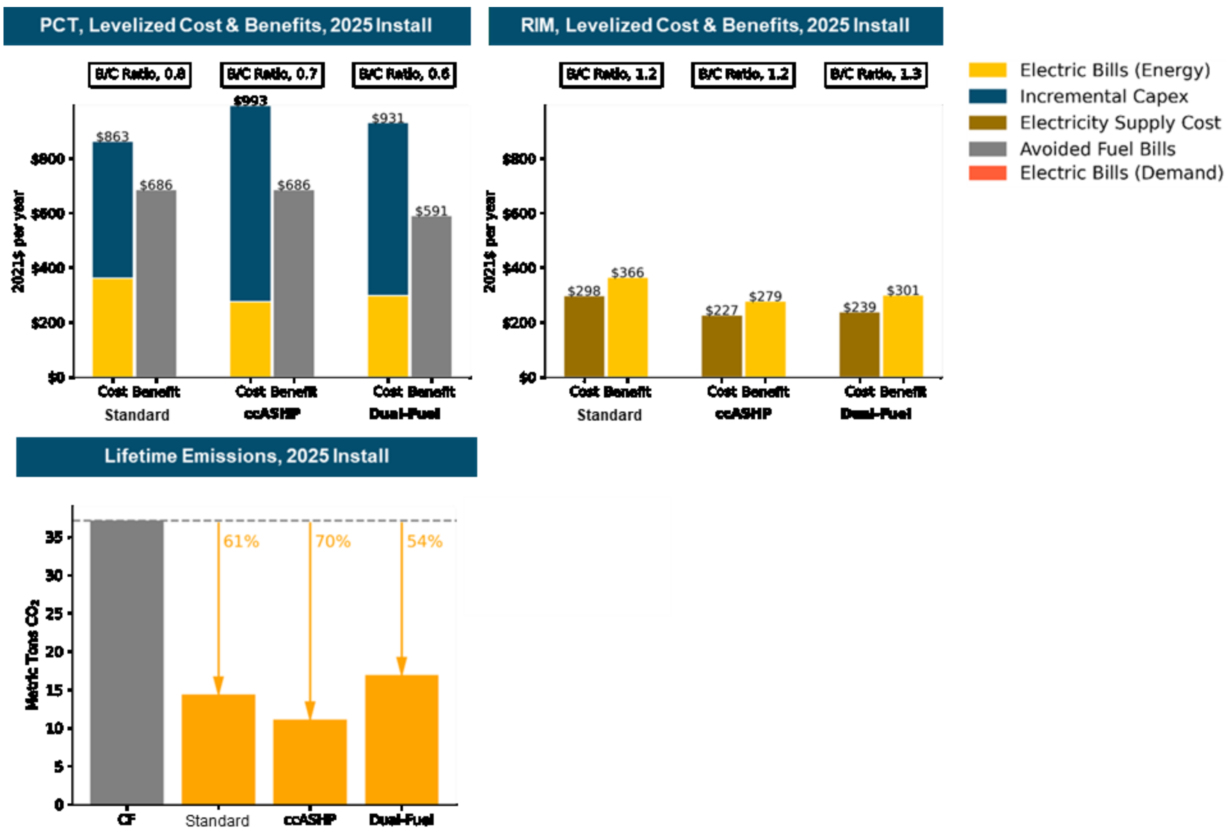
		PCT		RIM	Key Drivers
Residential Retrofit Gas	**Richland** all customers	Net Costs		Net Benefits	• High capital costs lead to net costs for participants • Low gas rates further contribute to net costs for participants even in 2035
	Tacoma all customers, **Clark** when A/C cost is not fully "avoidable"	Net Costs (2025)	Net Benefits (2035)	Net Benefits	• Decreasing capital costs of HPs and increasing gas bill savings eventually lead to net benefits for participants after 2035
	Clark when full A/C cost is "avoidable"	Net Benefits		Net Benefits	• Lower capital costs from avoiding full A/C costs contribute to net benefits for participants
	Inland when A/C cost is not fully "avoidable"	Net Costs		Net Costs	• Relatively low electric rates in Inland further add to the net benefits
	Inland when full A/C cost is "avoidable"	Net Benefits		Net Costs	• Compared to other COUs, Inland collects less revenues from those who electrify due to lower rates and incurs higher electric supply costs, contributing to net costs for ratepayers
Residential New Construction		Net Benefits		Net Benefits	• All-electric new constructions cost less upfront, even without avoided gas connection cost
Residential Delivered Fuel*		Net Benefits		Net Benefits	• Savings from avoiding delivered fuels are much higher than gas • Emissions savings are also larger as burning fuels emits more GHG compared to gas

2.3.2.2 Challenges: Residential Retrofit Building

Retrofit single family gas customer HVAC electrification results

Across all of the COU service territories, E3 found that residential HVAC electrification is higher cost for customers than a natural gas powered heating system. As highlighted in the PCT chart of Figure 2-10, a 2025 all-electric HVAC installation in Clark PUD's service territory yields $800-$1,000 of incremental cost, driven mainly by high installation costs, while providing only $500-$700 of avoided gas bills, leading to a net annualized incremental cost of $100 to $400. In comparison, RIM test benefits fall between $50 and $80. These ratepayer savings could be used by the COUs to provide incentives to support building electrification, though a revenue neutral incentive would fall well short of covering the incremental cost of electrification for participants.

Figure 2-10. Single-Family Residential Retrofit HVAC Electrification, 2025 Installation, Clark PUD



Compared to Clark PUD, customers in the other COU service territories have lower benefit-cost ratios their gas utilities' rates are lower than those of Northwest Natural, who serve Clark PUD. The high customer costs of residential HVAC electrification also remain a barrier into the future. By 2035, Clark PUD's service territory is the only COU in which any all-electric HVAC system achieves cost parity with the incumbent natural gas system. Table 2-10 shows benefit-cost-ratio results for all COUs.

Table 2-10. Benefit-Cost Ratio (B/C Ratio) Results for Single-Family Retrofit Residential HVAC Electrification, 2025 Installation. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

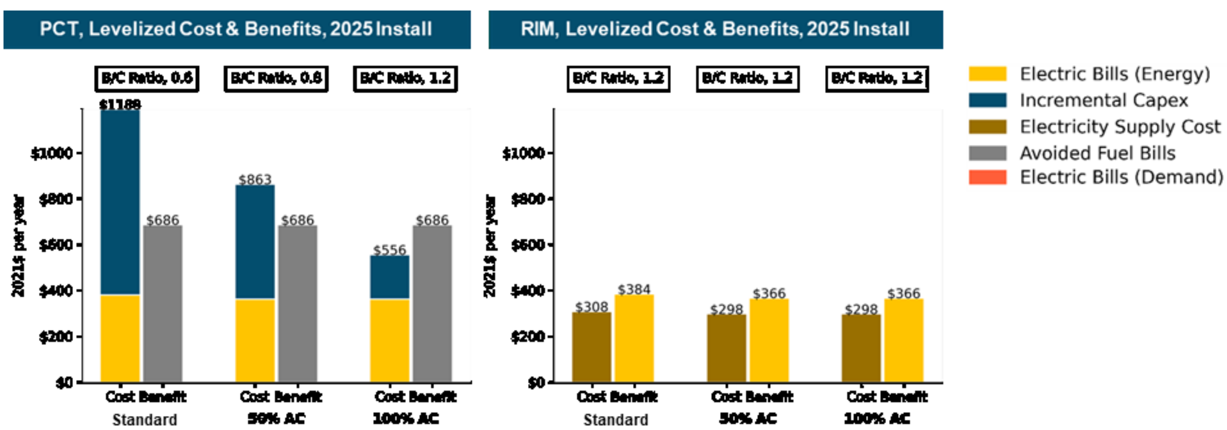
Cost Test	HP Technology	COU & Install Year							
		RES		IPL		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.6	0.7	0.7	0.9	0.6	0.8	0.8	1.0
	ccASHP	0.5	0.6	0.6	0.8	0.5	0.7	0.7	0.9
	Dual-Fuel ASHP	0.4	0.6	0.5	0.7	0.5	0.6	0.6	0.8
RIM	Standard ASHP	1.2	1.1	0.9	0.9	1.2	1.1	1.2	1.2

	ccASHP	1.2	1.1	0.9	0.9	1.2	1.1	1.2	1.2
	Dual-Fuel ASHP	1.4	1.4	1.1	1.1	1.2	1.2	1.3	1.2

Sensitivities on A/C install or replacement

As described in Chapter 2.2, the baseline results of the study are calculated using 50% of the A/C costs for the incumbent technology package, indicating that the A/C unit is only 50% depreciated when the furnace needs to be replaced. To understand the implications of A/C unit depreciation on HVAC electrification cost-effectiveness for single-family residential customers, E3 did a sensitivity analysis looking at 3 scenarios: 0% depreciation (existing A/C unit is retained), 50% depreciation (50% of new AC unit cost), and 100% depreciation (100% of new A/C unit cost). As highlighted in the PCT chart of Figure 2-11, a 2025 standard ASHP installation in Clark service territory yields about $1,200 of incremental levelized cost with 0% A/C depreciation, $900 of incremental cost with 50% A/C depreciation, and $600 of incremental cost with 100% A/C depreciation, making electrification cost-effective only with 100% A/C depreciation. In other words, building electrification retrofits are most likely to be cost-effective when early retirement of existing A/C equipment can be avoided. That situation would occur when a furnace and A/C unit fail at the same time, or in case where a customer who does not currently have A/C seeks to add it alongside a furnace replacement.

Figure 2-11. Single-Family Residential Retrofit A/C Install Cost Sensitivity, 2025 Installation, Clark PUD



Across the COU service territories, residential HVAC electrification is not cost-effective for customers replacing their furnace but keeping their A/C unit, as shown in Table 2-11. Conversely, for customers replacing both furnace and A/C unit, residential HVAC electrification is cost-effective for customers in all COUs other than Richland (which achieves cost parity by 2035).

Table 2-11. Benefit-Cost Ratio (B/C Ratio) Results for Single-Family Residential Retrofit A/C Install Cost Sensitivity, 2025 Installation. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	AC Cost	COU & Install Year			
		RES	IPL	Tacoma Power	Clark PUD

		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	**0% AC**	0.4	0.5	0.5	0.7	0.4	0.6	0.6	0.7
	50% AC	0.6	0.7	0.7	0.9	0.6	0.8	0.8	1.0
	100% AC	0.8	1.0	1.0	1.3	1.0	1.2	1.2	1.6
RIM	**0% AC**	1.2	1.1	1.0	1.0	1.2	1.2	1.2	1.2
	50% AC	1.2	1.1	0.9	0.9	1.2	1.1	1.2	1.2
	100% AC	1.2	1.1	0.9	0.9	1.2	1.1	1.2	1.2

Water heating electrification results

Compared to residential HVAC electrification, residential water heating electrification generates relatively larger bill savings due to larger efficiency gains over gas water heaters and relatively smaller incremental electricity supply costs due to water heating load being less coincident with the electric system peaks. With that said, residential water heater electrification still carries incremental costs compared to a gas water heater across all of the COU service territories. As highlighted in the PCT chart of Figure 2-12, a 2025 HPWH installation in Inland service territory yields about $400 of incremental cost, driven mainly by high capital costs, while providing only about $200 of avoided gas bills. Compared to Inland, customers in the other COU service territories achieve similar benefit-cost ratios, as shown in Table 2-12. The high customer costs of residential water heating electrification also remain a barrier into the future. By 2035, Clark PUD is the only COU in which HPWHs are cost effective compared to the incumbent gas water heater. Additionally, the benefit currently seen by utilities, which can be provided to customers via rebates or incentives, is not large enough to make up for high customer incremental cost.

Figure 2-12. Single-Family Residential Retrofit WH Electrification, IPL

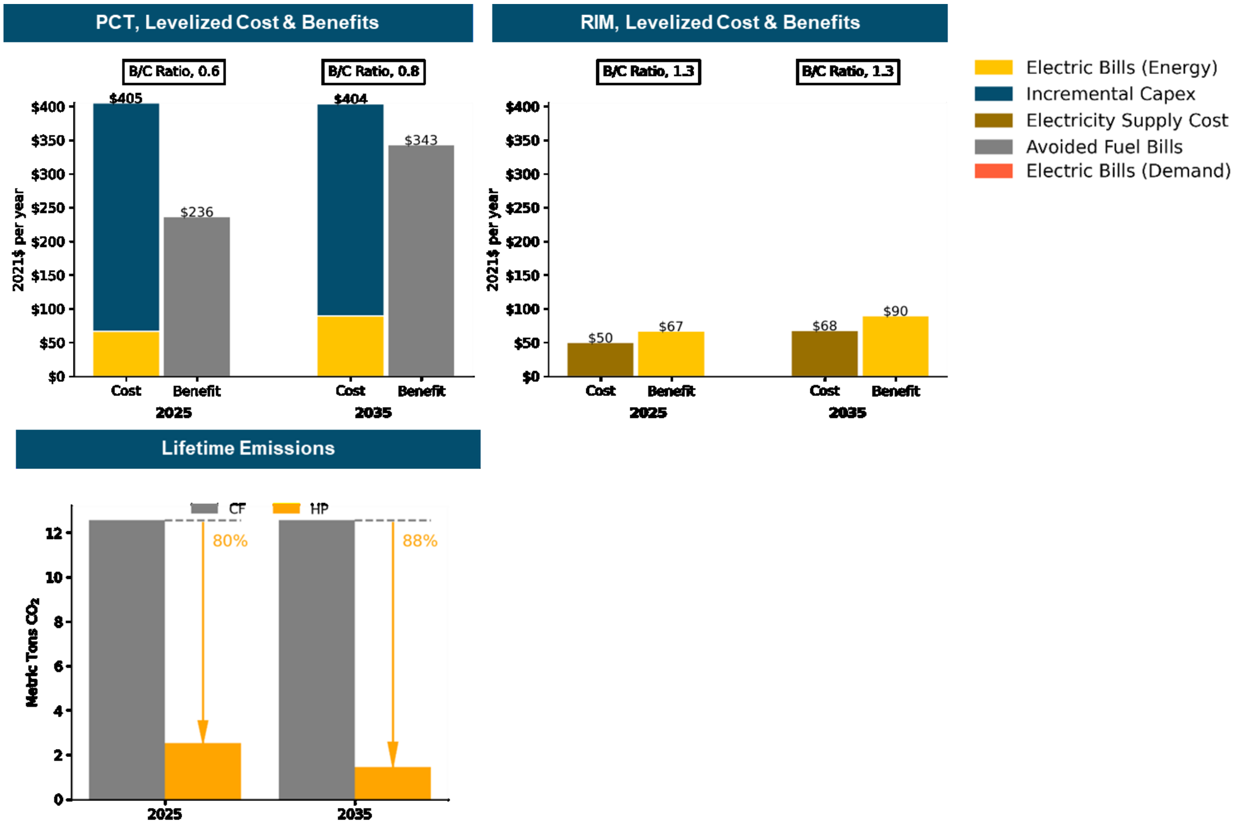


Table 2-12. Benefit-Cost Ratio (B/C ratio) Results for Single-Family Residential Retrofit WH Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	COU & Install Year							
	RES		IPL		Tacoma Power		Clark PUD	
	2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	0.5	0.7	0.6	0.8	0.6	0.8	0.7	1.1
RIM	1.5	1.5	1.3	1.3	1.8	1.8	1.6	1.6

2.3.2.3 Opportunities

Delivered Fuel Customers

Amongst all of the applicable COU service territories, residential HVAC electrification is cost-effective for "delivered fuel" customers, or customers who are heating their home using fuel oil or propane. Electrification for these customers is cost-effective mainly due to the high cost of delivered fuel. As highlighted in the PCT chart of Figure 2-13, a 2025 standard ASHP installation in Tacoma service territory yields about $900 of incremental cost, while providing about $1,000 of avoided fuel oil bills, making it cost-effective compared to a delivered fuel furnace + AC. By 2035, cold climate ASHPs also achieve cost parity for delivered fuel customers in both Clark and Tacoma service territories. Based on these results, delivered fuel customers are a likely to be strong candidates for HVAC electrification in Washington. Table 2-13 shows benefit-cost-ratio results for all COUs.

Figure 2-13. Single-Family Residential Retrofit HVAC Electrification for Delivered Fuel, 2025 Installation, Tacoma Power

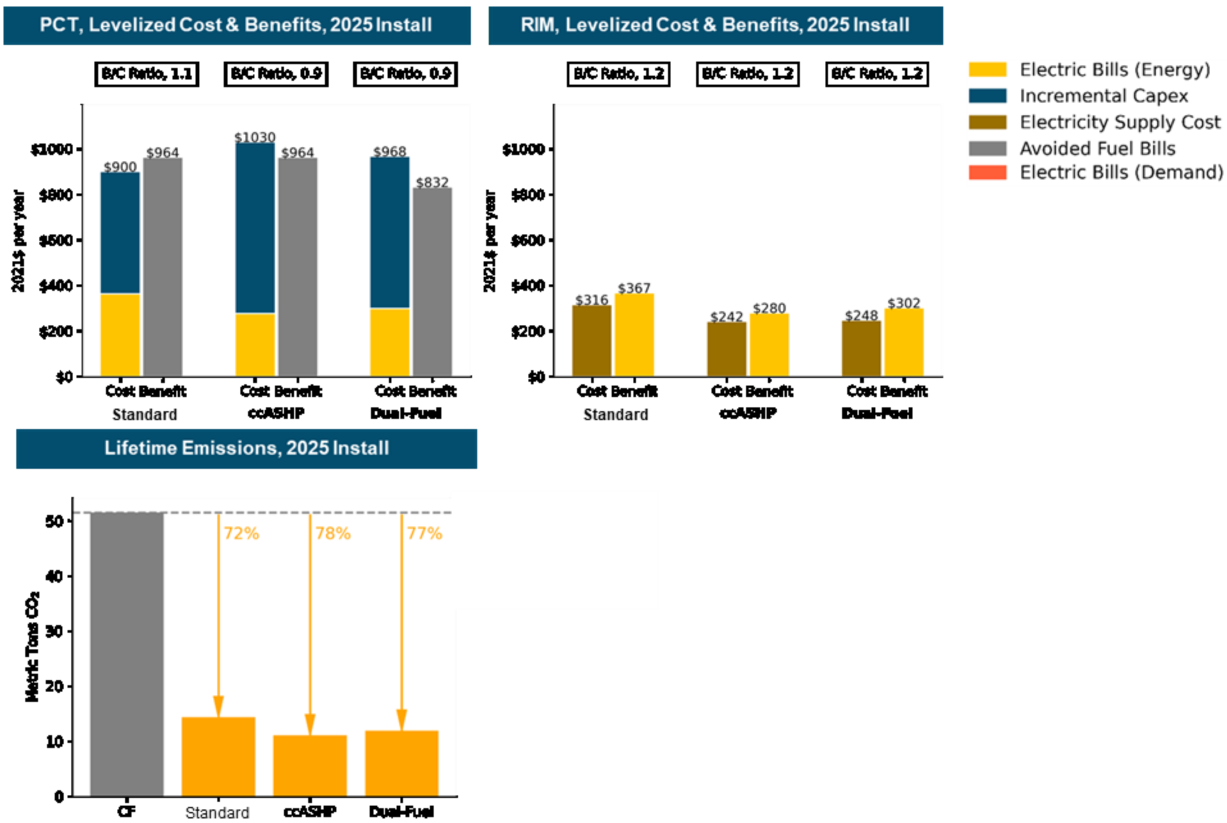


Table 2-13. Benefit-Cost Ratio (B/C Ratio) Results for Single-Family Residential Retrofit HVAC Electrification for Delivered Fuel. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year			
		Tacoma Power		Clark PUD	
		2025	***2035***	***2025***	***2035***
PCT	**Standard ASHP**	1.1	1.1	1.1	1.1
	ccASHP	0.9	1.0	0.9	1.0
	Dual-Fuel ASHP	0.9	0.9	0.9	0.9
RIM	**Standard ASHP**	1.2	1.1	1.2	1.2
	ccASHP	1.2	1.1	1.2	1.2
	Dual-Fuel ASHP	1.2	1.2	1.3	1.2

New construction

For residential new construction in the state of Washington, E3 assumed that electrification would be applied to the full building rather than one specific system, which avoids the need to install a gas connection. Full building electrification includes all-electric HVAC, a heat pump water heater, electric dryer, and electric cooktop. In addition, E3 modeled new construction to meet all envelope requirements in the latest approved Washington state energy code. A tighter envelope allows for smaller HVAC systems and results in lower and less peaky heating loads.

With all of this in mind, E3 determined that residential full building electrification for new construction is cost-effective to customers across all COU service territories, mainly due to lower upfront capital costs. Even without including avoided gas connection costs, electrification is still cost-effective. As highlighted in the PCT chart of Figure 2-14, all-electric new construction installed in 2025 in Tacoma service territory yields about $500 of incremental cost, while providing about $900 of avoided gas bills and upfront cost savings. With the addition of avoided gas connection cost, there is a total of about $1,600 benefit. In addition, except for Inland, all-electric residential new construction is cost-effective for all COUs, mainly due to lower electricity supply costs, which are a result of less peaky loads. Table 2-14 shows benefit-cost-ratio results for all COUs. Across the state of Washington, all-electric residential new construction seems to make financial sense for both customers and utilities.

Figure 2-14. Single-Family Residential New Construction Full-Building Electrification, Tacoma Power

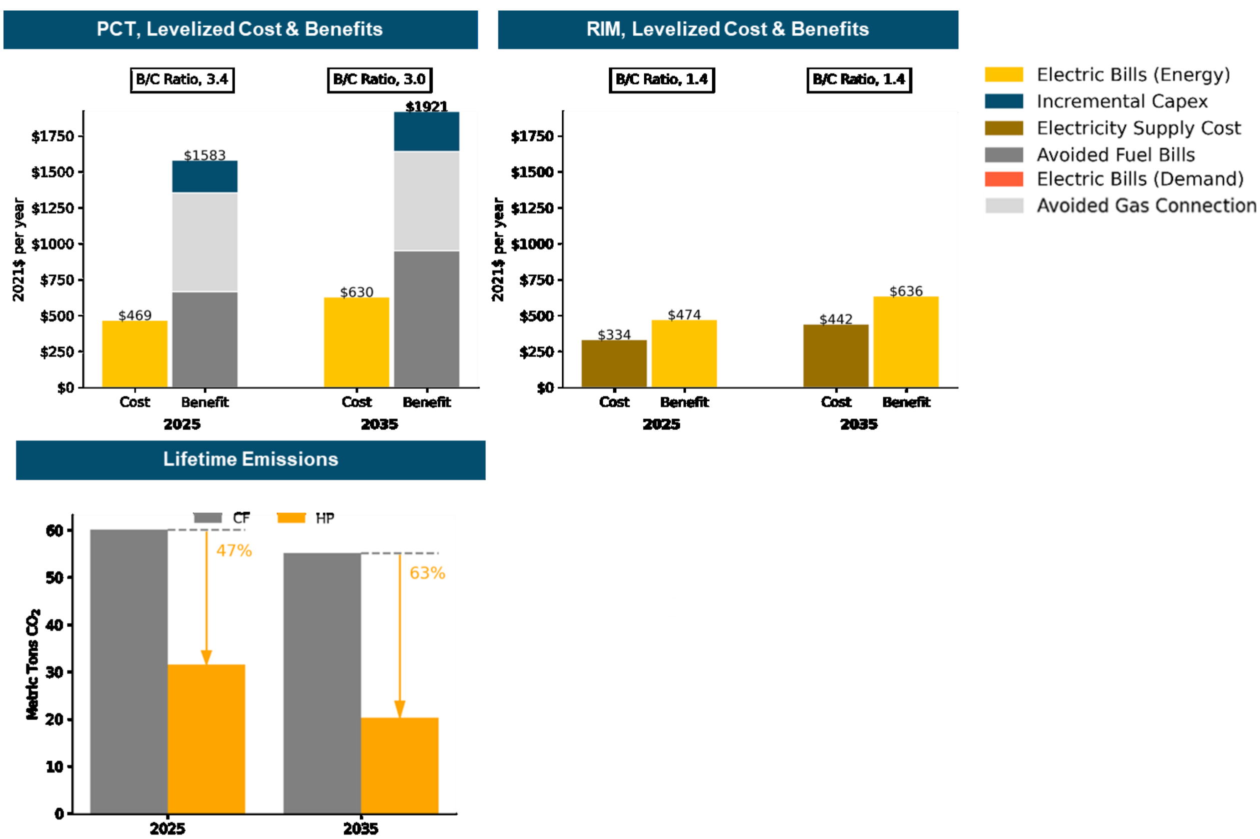


Table 2-14. Benefit-Cost Ratio (B/C Ratio) Results for Single-Family Residential New Construction Full-Building Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	COU & Install Year							
	Richland		Inland		Tacoma		Clark	
	2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	1.9	2.0	2.4	2.5	1.9	2.0	2.3	2.4
RIM	1.2	1.2	0.9	0.9	1.4	1.4	1.4	1.4

2.3.3 Commercial Sector Benefit Cost Results

2.3.3.1 Summary of commercial Results

E3's evaluation of the economics of electrification for different commercial use cases shows that there are significant economic barriers to electrifying existing office and retail buildings in Washington state. For office and retail customers across all the COU service territories within this study, building electrification currently is not cost-effective. This is a result of high capital costs and high demand charges, which electrification further increases. Even with decreasing capital costs of heat pumps and increasing gas bill savings over time, building electrification is still not cost-effective in 2035 in most COU service territories.

With that said, there are opportunities for electrification that exist within the commercial sector of Washington state. Within the office and retail building sector, partial electrification is more economically feasible for customers in Tacoma and Clark service territories who opt to install a dual-fuel heat pump system, which avoids the large increases in electric demand charges that occur from full electrification. Another opportunity for cost-effective electrification in the state is healthcare facilities. Electrification is cost-effective or nearly cost-effective for most healthcare customers in the state, mainly due to the fact that healthcare facilities tend to have very high heating energy consumption which leads to significant avoided gas bills. Finally, electrification of commercial new construction is cost-effective to all office, retail, and healthcare customers across the state, mainly due to lower upfront costs and the potential to avoid the cost of gas connection.

Electrification currently creates a benefit for the COUs from electrification of most commercial office buildings, all commercial retail buildings, and all new construction, mainly due to incremental revenues from demand charges. This opens the door to utility-provided incentives for electrification within the commercial sector. Conversely, electrification of buildings with dual-fuel heat pumps current creates a small net cost for utilities because dual-fuel heat pumps help mitigate peak load increase and thus limit the increase in customer demand charges, which are a main source of revenue for utilities.

Table 2-15 shows a summary of HVAC electrification results for commercial retrofit buildings. Table 2-16 shows a summary of water heating electrification results for commercial retrofit buildings and new construction results.

Table 2-15. Commercial Retrofit HVAC Electrification Results Summary

	PCT		RIM	Key Drivers
Commercial Office Retrofits (Clark)	Net Costs (2025)	Net Benefits (2035)	Net Costs	• Dual-fuel HPs are cost-effective because they can significantly reduce the demand charge for the "peaky" HVAC load in offices • The low demand charge from using dual-fuel HPs lead to less utility revenue and thus net costs for ratepayers
Commercial Retail Retrofits (Clark)	Net Costs (2025)	Net Benefits (2035)	Net Benefits	• Standard HPs are cost-effective due to higher heating need and less "peaky" load in retail compared to office
Commercial Office and Retail Retrofits (Tacoma, Richland, Inland)	Net Costs		Net Benefits	• Low gas rates lead to lower gas bill savings from electrification • Colder climate also contributes to higher electricity costs
Commercial Small Healthcare Retrofits (Richland, Inland)	Net Benefits		Net Costs	• Dual-fuel HPs are cost-effective but lead to net costs for ratepayers
Commercial Large Healthcare Retrofits (Clark, Tacoma)	Net Benefits		Net Benefits	• High heating needs in large healthcare buildings lead to high gas savings from electrification • All HP types are cost-effective

Table 2-16. Commercial New Construction and Water Heating Electrification Results Summary

	PCT	RIM	Key Drivers
New construction			
Commercial Office, Retail and Healthcare New Construction	Net Benefits	Net Benefits	• Relatively low incremental capital costs contribute to net benefits for participants • New construction has tighter shells, and thus lower electricity supply costs
Water Heating Electrification			
Commercial Small Office	Net Costs	Net Benefits	• Small offices consume much less energy for water heating than other building types, and thus bill savings from electrification are relatively small
Commercial Small Retail (Tacoma, Richland, Inland)	Net Costs	Net Benefits	• Low gas rates lead to low gas bill savings and thus net costs for participants
Commercial Small Retail (Clark)	Net Benefits	Net Benefits	• Small retail consumes more energy for water heating than office, and thus larger bill savings lead to net benefits for participants
Large Commercial, Healthcare Retrofits (Clark, Tacoma)	Net Benefits	Net Benefits	• Large commercial buildings and healthcare facilities consume the most energy for water heating among all building types modeled, and thus significant fuel savings lead to net benefits across all cost tests

2.3.3.2 Challenges: Commercial Retrofit Buildings

Commercial office results

Electrification of office buildings creates a net cost for customers in three of the four COU's service territories, with Clark PUD being the exception. One of the main contributing factors to poor cost-effectiveness for commercial offices is demand charges. As highlighted in the PCT chart of Figure 2-15, a 2025 all-electric HVAC installation in IPL's service territory yields $6,000-$7,000 of incremental customer costs per year, while providing only $4,000 of avoided gas bills. A dual-fuel system yields lower incremental costs, mainly by avoiding much of the incremental demand charge, but still creates a cost burden on customers. The exception is in Clark PUD's service territory where dual fuel systems achieve cost parity due to the high gas bill savings. The high customer costs of commercial office electrification also remain a barrier into the future. With that said, utilities see relatively large benefits due to the high demand charges, which means there is potential for utility incentives to offset the high customer incremental costs. Table 2-17 shows benefit-cost-ratio results for all COUs.

Figure 2-15. Small Office Retrofit HVAC Electrification, IPL

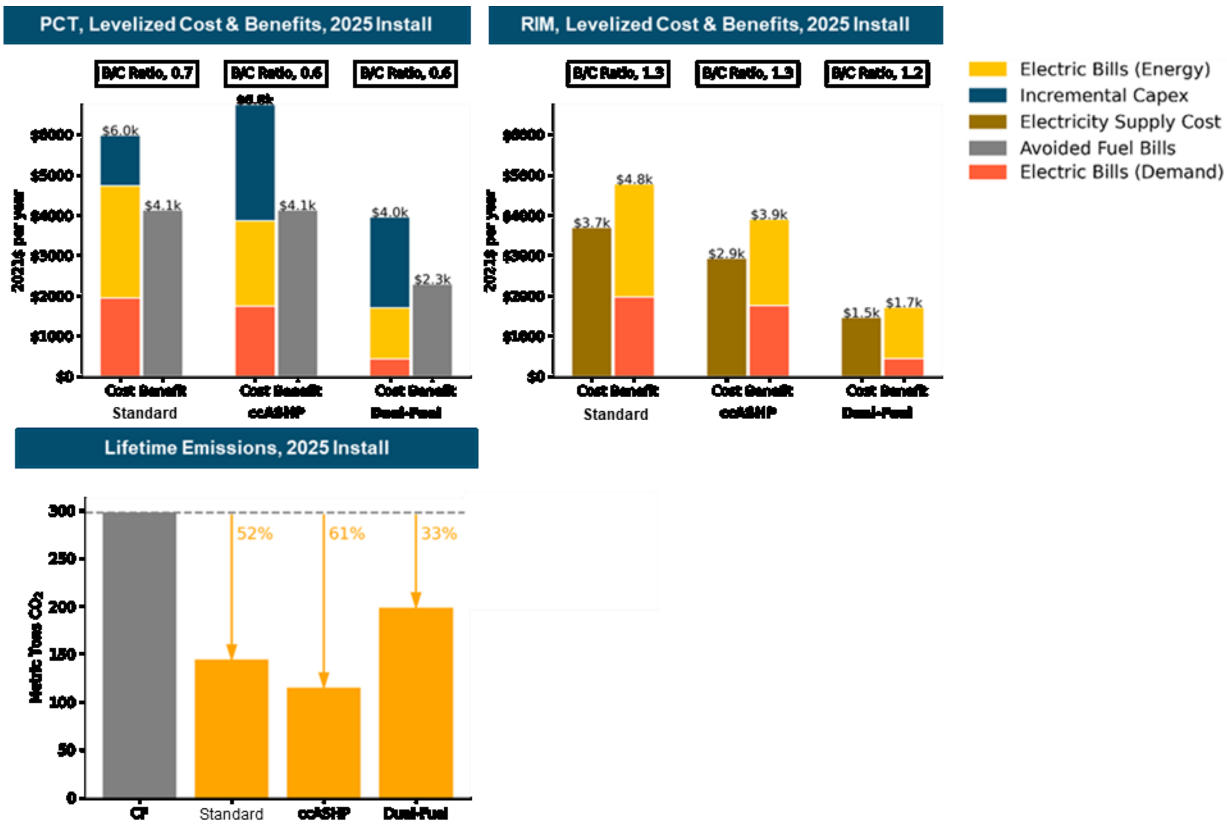


Table 2-17. Benefit-Cost Ratio (B/C ratio) Results for Small Office Retrofit HVAC Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year							
		RES		IPL		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.7	0.8	0.7	0.7	0.5	0.6	0.8	0.9
	ccASHP	0.5	0.7	0.6	0.6	0.5	0.5	0.7	0.8
	Dual-Fuel ASHP	0.5	0.7	0.6	0.6	0.7	0.9	1.0	1.3
RIM	Standard ASHP	1.2	1.2	1.3	1.3	1.9	2.0	1.6	1.7
	ccASHP	1.3	1.3	1.3	1.3	2.0	2.2	1.8	1.8
	Dual-Fuel ASHP	1.0	1.0	1.2	1.2	0.9	0.9	0.8	0.8

Commercial retail results

In all the COU service territories, electrification of retail buildings creates a net cost for customers. Like commercial offices, a key factor in the customer cost burden is high demand charges which are driven up by electrification. As highlighted in the PCT chart of Figure 2-16, a 2025 all-electric HVAC installation in Inland service territory yields $2,000-$3,000 of incremental cost, while providing only $1,500 of avoided gas bills. A dual-fuel system yields lower incremental electricity bills, but drives up the upfront capital cost and therefore still creates a cost burden on the customer. Compared to Inland, customers in Richland and Tacoma service territories experience similar cost burdens for electrifying retail buildings, as shown in Table 2-18. In Clark service territory, installing a standard ASHP achieves cost parity with the incumbent gas system. In the future, the economics of electrification do improve, but for the most part still create a cost burden to customers everywhere other than Clark service territory. Unlike for commercial offices, utilities do not see nearly as large a benefit from commercial retail electrification, lowering the potential for utility incentives to offset customer costs.

Figure 2-16. Small Retail Retrofit HVAC Electrification, RES

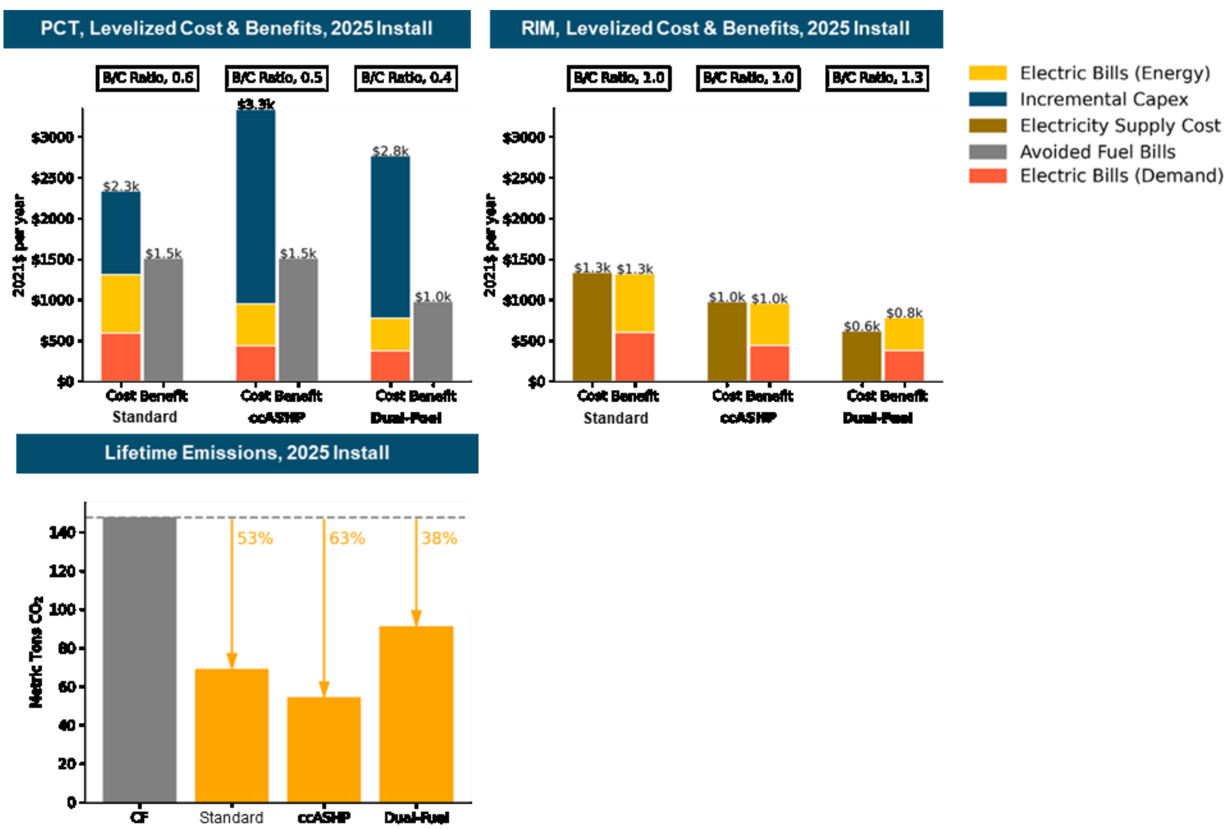


Table 2-18. Benefit-Cost Ratio (B/C ratio) Results for Small Retail Retrofit HVAC Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year							
		RES		IPL		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	**Standard ASHP**	0.6	0.8	0.7	0.9	0.7	0.9	1.0	1.3
	ccASHP	0.5	0.6	0.5	0.7	0.5	0.7	0.8	1.0
	Dual-Fuel ASHP	0.4	0.5	0.4	0.6	0.6	0.7	0.8	1.1
RIM	**Standard ASHP**	1.0	1.1	1.2	1.4	1.2	1.5	1.0	1.1
	ccASHP	1.0	1.0	1.1	1.3	1.3	1.5	1.0	1.1
	Dual-Fuel ASHP	1.3	1.3	1.4	1.7	1.0	1.1	0.8	0.9

2.3.3.3 Opportunities

Dual-fuel heat pumps in commercial office buildings

Although full electrification of commercial office retrofits is not currently cost-effective, dual-fuel HP systems provide an interesting opportunity for partial electrification, especially for commercial office customers in Tacoma Power's and Clark PUD's service territories. Dual-fuel HP systems generate lifecycle savings mainly by avoiding a large increase in electric demand charge while retaining a small gas bill. As highlighted in the PCT chart of Figure 2-17, a 2025 dual-fuel HP installation in Clark PUD's service territory yields about $40,000 of incremental cost, while providing about $46,000 of avoided gas bills. A 2025 installation of a dual-fuel HP system achieves net benefit or cost parity to the incumbent gas system for small and large commercial offices in Clark PUD's service territory. By 2035, a dual-fuel HP system also achieves cost parity to the incumbent gas system for large commercial offices in Tacoma service territory. Table 2-19 shows benefit-cost-ratio results for all COUs.

Figure 2-17. Large Office Retrofit HVAC Electrification, Clark PUD

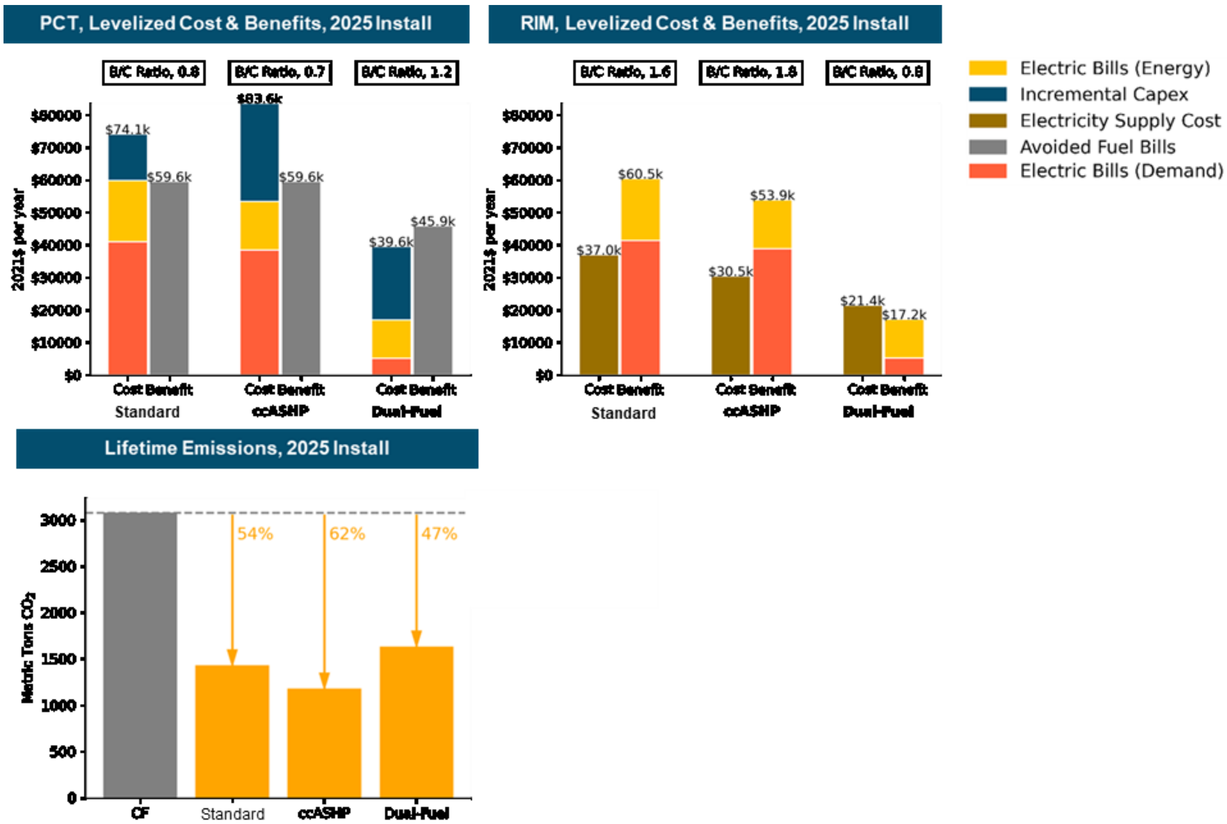


Table 2-19. Benefit-Cost Ratio (B/C ratio) Results for Large Office Retrofit HVAC Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year			
		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.6	0.6	0.8	0.9
	ccASHP	0.5	0.6	0.7	0.9
	Dual-Fuel ASHP	0.8	1.0	1.2	1.5
RIM	Standard ASHP	1.9	2.0	1.6	1.7
	ccASHP	2.0	2.2	1.8	1.8
	Dual-Fuel ASHP	0.9	0.9	0.8	0.8

Commercial healthcare

Across all the applicable COU service territories, electrification is cost-effective or nearly cost-effective for healthcare customers. This is mainly because healthcare facilities tend to have very high heating energy consumption which leads to significant avoided gas bills. As highlighted in the PCT chart of Figure 2-18, large healthcare electrification in 2025 in Tacoma service territory yields about $260,000-$330,000 of incremental cost, while providing about $480,000-$530,000 of avoided gas bills. In 2025, electrification nearly achieves cost parity to a chiller + boiler system for small healthcare in Richland and Inland service territories and achieves net benefits for large healthcare in Clark and Tacoma service territories. By 2035, healthcare electrification generates net benefits across all COU service territories, as shown in Table 2-20.

Figure 2-18. Large Healthcare Retrofit HVAC Electrification, Tacoma Power

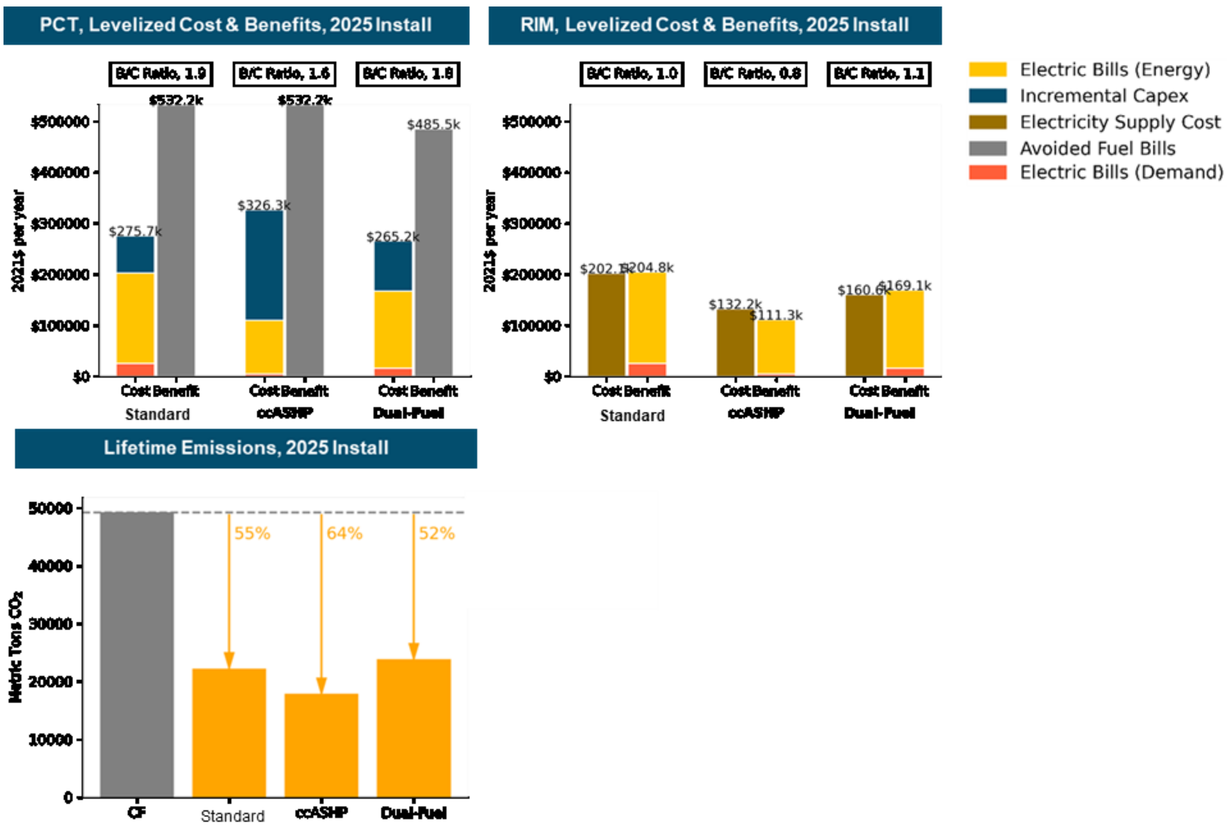


Table 2-20. Benefit-Cost Ratio (B/C ratio) Results for Large Healthcare Retrofit HVAC Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year			
		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	1.9	2.3	2.9	3.6
	ccASHP	1.6	2.2	2.4	3.2
	Dual-Fuel ASHP	1.8	2.3	2.7	3.5
RIM	Standard ASHP	1.0	1.0	1.0	1.0
	ccASHP	0.8	0.8	0.8	0.8

	Dual-Fuel ASHP	1.1	1.0	1.0	1.0

Commercial new construction

For commercial new construction in the state of Washington E3 assumed that electrification would be applied to the full building rather than one specific system to avoid gas connection for the building. Full building electrification includes all-electric HVAC and water heater. Like residential buildings, new construction has been modeled to meet all envelope requirements in the latest approved Washington state energy code.

With all of this in mind, E3 determined that commercial full building electrification for new construction is cost-effective to all office, retail, and healthcare customers across all COU service territories, mainly due to lower upfront capital costs and avoided gas connection costs. As highlighted in the PCT chart of Figure 2-19, all-electric new construction installed in 2025 for a small office in Inland service territory yields about \$4,000-\$5,000 of incremental cost, while providing about \$5,000 of avoided gas bills and gas connection cost. In addition, all-electric commercial new construction is cost-effective for the utilities as shown in the RIM test on Figure 2-19, mainly due to lower electricity supply costs, which are a result of less peaky loads. Across the state of Washington, all-electric commercial new construction makes financial sense for both customers and utilities, as shown in Table 2-21.

Figure 2-19. Small Office New Construction HVAC Electrification, IPL

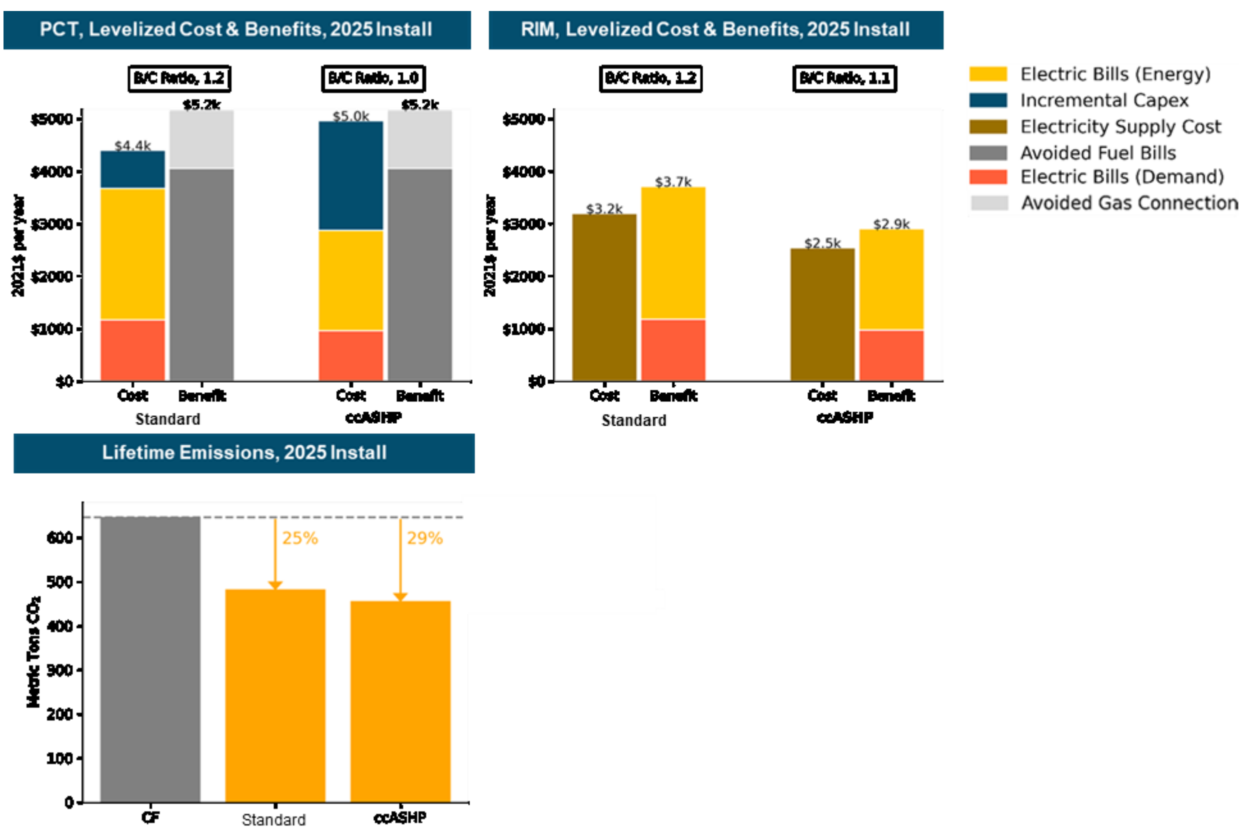


Table 2-21. Benefit-Cost Ratio (B/C ratio) Results for Small Office New Construction HVAC Electrification. B/C ratio greater than 1 indicates net lifecycle benefits; B/C ratio less than 1 indicates net lifecycle costs.

Cost Test	HP Technology	COU & Install Year							
		RES		IPL		Tacoma Power		Clark PUD	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	Standard ASHP	1.3	1.1	1.2	1.1	1.3	1.1	1.9	1.7
	ccASHP	1.1	0.9	1.0	1.0	1.1	1.0	1.7	1.5
RIM	Standard ASHP	1.1	1.0	1.2	1.3	1.2	1.4	1.2	1.1
	ccASHP	1.0	1.0	1.1	1.3	1.2	1.4	1.1	1.1

2.3.4 Sensitivity Studies

High gas cost sensitivity

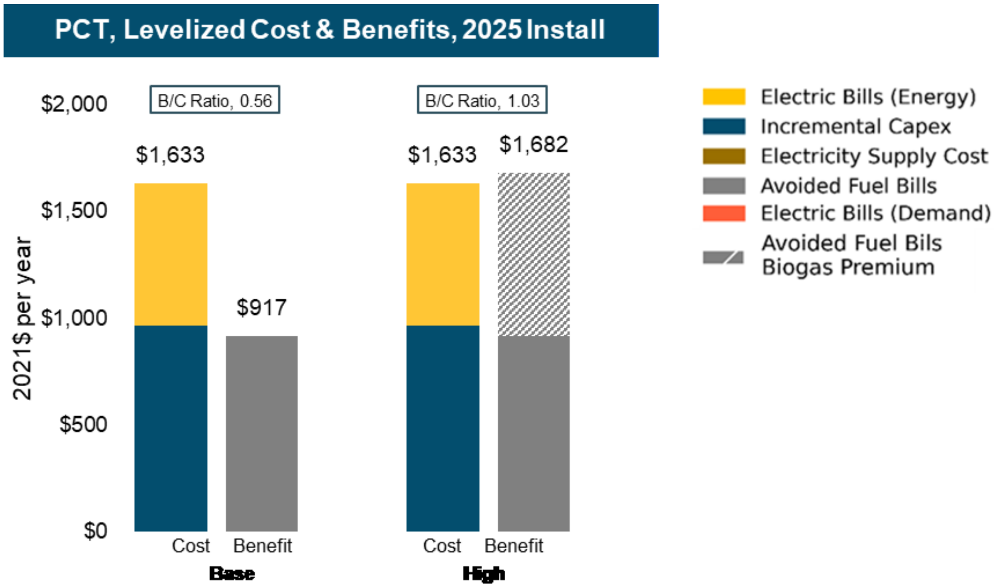
E3 conducted a high gas cost sensitivity analysis that assessed the impacts of a blend of renewable natural gas (RNG) in the gas pipeline. For the purposes of this analysis, E3 used the following assumptions:

- RNG blend in the pipeline ramps up such that RNG achieves the same amount of GHG emissions reductions as electrification by 2030 and thereafter
- RNG price of $22.50/MMBtu based on E3's Pacific Northwest Pathways to 2050 study[18]
- RNG is net-zero GHG emissions, consistent with WA state GHG inventory

The sensitivity analysis, as highlighted in the PCT chart of Figure 2-20, shows that the higher gas costs tilt the scale for single-family retrofit customers and make HVAC electrification cost-effective for participants. This means that as the RNG blend in the gas pipeline increases in the future, electrification economics will continue to improve.

[18] E3's Pacific Northwest Pathways to 2050 report can be accessed via: https://www.ethree.com/wp-content/uploads/2018/11/E3_Pacific_Northwest_Pathways_to_2050.pdf

Figure 2-20. High Gas Cost Sensitivity, Single-Family Residential Retrofit HVAC Electrification, 2025 Installation, RES

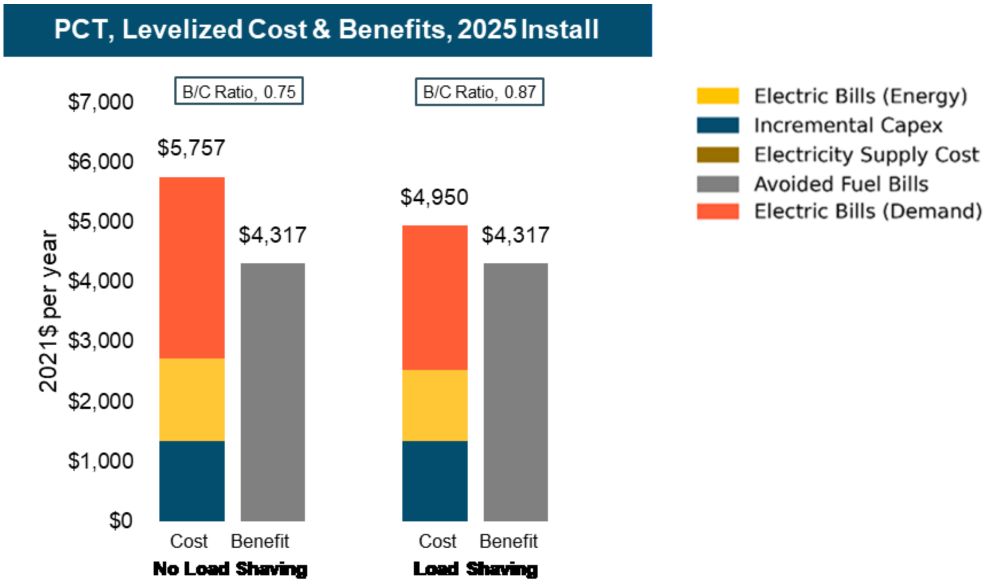


Demand response sensitivity

E3 conducted a sensitivity analysis on the impacts of demand response in the commercial building sector. Demand response events were modeled as a signal sent by the electric utility to expand customers' HVAC system comfort setpoints, allowing buildings to float up to 78°F in the cooling season and down to 67°F in the heating season. These are expanded from the traditional 70-75°F comfort range. For the purposes of this analysis, the demand response signal was sent for the top 10% of hours with highest marginal capacity cost. E3 assumed that the demand response functionality would be more attractive to all-electric customers than mixed-fuel customers, due to the increased demand charge for all-electric customers. Therefore, to calculate cost effectiveness, demand response functionality was included in the electrified technology and excluded from the incumbent gas technology.

E3 found that demand response reduces commercial customer demand charges by about 20% and energy charges by about 15% under the TMY weather conditions modeled in this study (results shown in Figure 2-21), bringing electrification closer to cost-effectiveness for commercial customers. Furthermore, demand response reduces electricity supply costs by about 25%. These results suggest an opportunity for utilities to promote electrification paired with demand response, helping reduce costs for both the customer and the utility. Further assessment for the technical feasibility and costs of DR programs are needed to determine what is level and types of demand response offerings are feasible for COUs to implement. Also, the effect of demand response during cold snaps may be different but were not modeled in this study, which considered typical weather conditions.

Figure 2-21. Demand Response Sensitivity, Small Office Retrofit Full Building Electrification, 2025 Installation, Clark PUD



High electricity cost sensitivity

A final sensitivity analysis was conducted to evaluate the impacts of a higher electricity supply cost on electrification on the COUs and their ratepayers. The electricity supply costs applied in the sensitivity consist of the following components:

- **Increased transmission capacity cost of $39/kW-yr by 2030**, based on a proposed cross-Cascades transmission project in Oregon that was eventually cancelled[19], reflecting cost of building new transmission lines crossing the Cascades
- **Increased distribution capacity cost of $125/kW-yr by 2030**, based on the deferred value of a new distribution line investment from the Energize Eastside project being undertaken by PSE[20], reflecting cost of building new distribution systems in urban areas
- **Increased generating capacity cost of $112/kW-yr by 2030**, reflecting the levelized fixed cost of a greenfield hydrogen combustion turbine based on E3's estimate and consistent with other recent studies[21].

Under this high electricity costs sensitivity, the cost-effectiveness of electrification decreases and, in some cases, leads to net costs for ratepayers (Figure 2-22).

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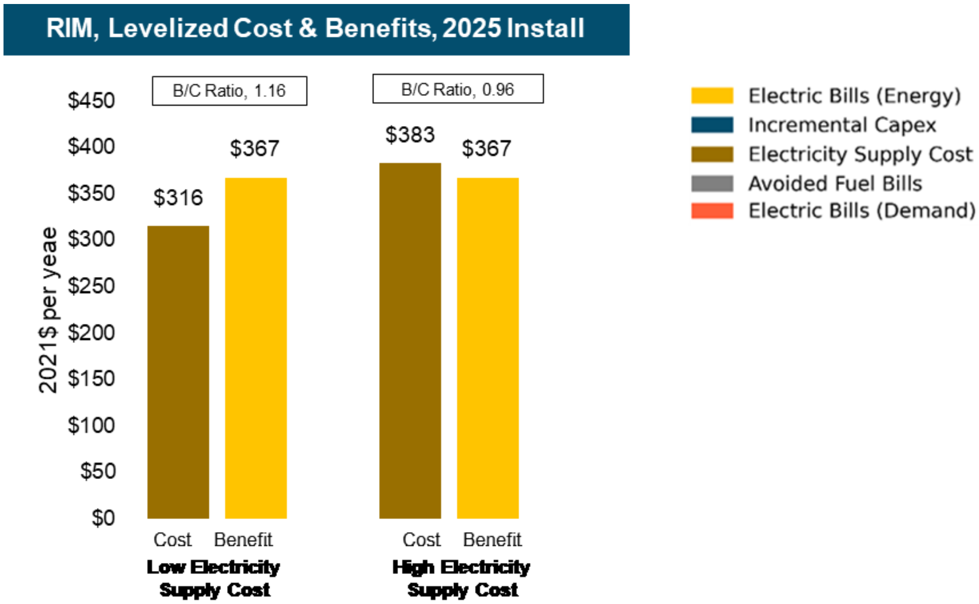
[19] $2B transmission lines that were originally planned throughout Oregon by PacifiCorp, PGE and Idaho Power. https://djcoregon.com/news/2010/12/28/2b-in-transmission-lines-planned-in-oregon/

[20] Deferred value of the Energize Eastside project is calculated based on costs in E3's Non-wires solution analysis for PSE. https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/PSEScreeningStudyFebruary2014.pdf

[21] E3's cost estimate for a greenfield hydrogen combustion turbine is consistent with those used in NREL's 2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook for "renewable energy combustion turbines". https://www.nrel.gov/docs/fy22osti/80641.pdf

Figure 2-22. High Electricity Supply Cost Sensitivity, Single Family Residential Retrofit HVAC Electrification, 2025 Installation, Tacoma Power



2.4 Benefit Cost Analysis Key Conclusions

Based on the Benefit Cost Analysis results, the following key conclusions can be made about building electrification across the state of Washington.

Building electrification reduces total greenhouse gas (GHG) emissions across all the building segments and regions studied. For example, a conversion in 2025 from natural gas space heating to an air source heat pump reduces GHG emissions by 5-60% throughout the expected useful lifetime of the equipment. The same conversion in 2040 will achieve higher lifetime GHG savings of 34-75% as the Clean Energy Transformation Act (CETA) increases the supply of decarbonized generation serving Washington.

There are several near-term opportunities where electrification can deliver cost savings for COU customers, including:

+ **All-electric new construction** offers one of the most promising near-term opportunities for building electrification. Compared to a mixed-fuel new home that needs air conditioning, an all-electric new home saves ~$2,000 in upfront participant costs. Considering both upfront costs and bill savings, all-electric new homes would save ~$1,000 per year over the lifetime of the equipment. Among the segments modeled in this study, all-electric commercial new construction was found to require higher upfront costs, but still generate lifecycle savings for participants due to utility bills savings.
+ **Homes that need a new air conditioner (A/C) or a replacement for an existing A/C** represent another savings opportunity when retrofitting from gas-fired space heaters to air source heat pump HVAC systems. Heat pumps provide both heating and cooling, so they avoid the cost of both a furnace and an air conditioner in buildings. Bill savings from switching to heat pumps are

higher than the first cost premium for these customers across three of the four COUs studied and thus generate lifetime savings for them.

- **Homes that currently use oil- or liquified petroleum gas-fired (LPG-fired) space heaters** will generate savings when retrofitting to air source heat pump HVAC systems. Delivered fuels such as fuel oil or LPG are more expensive that natural gas when used for heating homes. Lifetime bill savings from space heating alone, when switching from using delivered fuels to electric heat pumps, outweigh the first cost premium and help generate lifetime savings of approximately $60 per year.
- **Retrofits to dual-fuel heat pump HVAC systems** represent savings opportunities for commercial office buildings. Office buildings were found to incur large increases in demand charges by switching to all-electric heat pump HVAC systems. A dual-fuel heat pump HVAC system, which keeps the existing gas heating system and adds a heat pump system, uses the heat pump as the sole source for heating most of the year but switches to the gas back-up system during cold temperatures. By leveraging the existing gas system as a backup heating source, a dual-fuel system helps reduce the otherwise significant increase in peak load and demand charges. E3 found that a dual-fuel system achieves cost parity with a like-for-like replacement of an existing gas system in office buildings while achieving significant GHG savings.
- **Retrofits of healthcare buildings to air source heat pump HVAC systems** represent another savings opportunity among existing commercial buildings. Healthcare buildings oftentimes have very high utilization of their HVAC systems. Therefore, the resulting bill savings from switching to heat pumps are found to be the highest among all studied building types and outweigh the first cost premium in these buildings. However, an important caveat is that this study only models a generic healthcare building. Specific buildings, such as hospitals with emergency rooms, may require backup power, such as a natural gas generator, onsite per federal regulations. Such requirements may result in additional costs for electrification, which are not evaluated in this study.

Although building electrification can be lower cost in many applications today, this study found challenges for many customers to achieve cost savings, including:

- **The high incremental first costs of electrification in retrofit buildings** were found to be the major barrier to electrification. The equipment cost of a heat pump HVAC system is higher than a gas heating system. In addition, retrofits from an existing gas-fired heating system to a heat pump HVAC system oftentimes require extra work such as additional wiring or service panel upgrades.
- **Low natural gas rates** make electrification more challenging for customers. The lower bill savings, as a result, create another barrier to electrification for customers, especially those in the RES service area where natural gas rates are lower than other three COUs.

Non-participating electric utility ratepayers could see a small benefit from building electrification. The increase in COU revenues from those who electrify (participants) will be slightly higher than the COUs' costs to serve incremental loads for three of the four COUs. Those revenues could be used to provide incentives to partially overcome the incremental upfront and lifecycle costs associated with electrification (discussed below) without raising rates for non-participants. However, in some areas, such as urban areas where new distribution systems are very costly or places where new transmission lines are very expensive to build, the electricity supply cost to serve the incremental electrification load could become higher than the utility revenues from participants. In those places, non-participating ratepayers could see higher costs because of building electrification. **It is also important to note that E3 found that incremental revenues earned by the COUs are unlikely to be sufficient to provide incentives that cover the full incremental cost of electrification for participants.**

COUs could leverage demand response (DR) programs to help lower the peak system load and electric bills for commercial customers. A DR sensitivity conducted in this study found that by expanding the thermostat setpoints of office buildings by 3 °F during the system peak hours, heating demand could be lowered by as much as 20% during the peak period of a typical winter. Further assessment for the technical feasibility and costs of DR programs are needed to determine what is feasible for utilities to implement.

If cost of gas exceeds certain point due to market-driven price increase or the exclusive use of low-carbon gas, building electrification could become cost effective. E3 conducted a sensitivity analysis to estimate the cost of reducing GHG emissions from pipeline gas by blending hydrogen and renewable natural gas with fossil-based natural gas. The result that electrification provides savings relative to exclusive use of low-carbon gas, is consistent with findings from the 2021 Washington State Energy Strategy.

3 System Load Impact Analysis

3.1 Introduction

E3's System Load Impact Analysis evaluates potential increases in energy sales and peak demand for each COU when electrification of heating happens at the pace and scale envisioned in the Washington State Energy Strategy. E3 designed seven scenarios for the load impact analysis with varying assumptions about heat pump technologies installed, their performance characteristics and levels of building shell improvement.

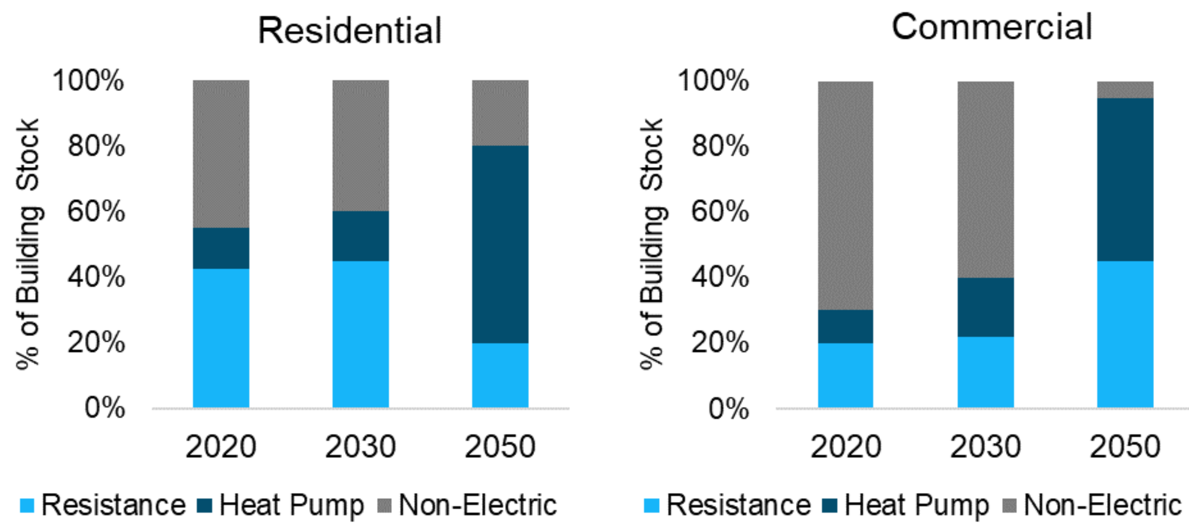
This analysis aims to identify challenges that building electrification may bring on the electric grid, and to inform potential actions that COUs can take to reduce its impact.

3.2 Modeling Approach

3.2.1 Electrification adoption trajectories

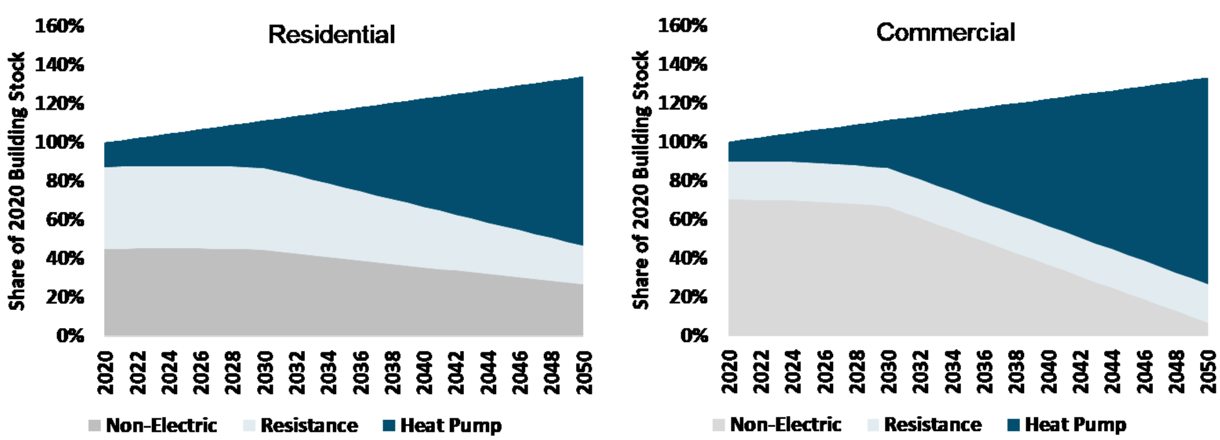
E3 developed annual energy sales impacts that are mostly consistent with changes in building stock modeled in the *2021 Washington State Energy Strategy*'s (SES) Electrification Scenario. The SES assumes the stock of non-electric homes decreases from approximately 45% in 2020 to 20% in 2050 and the share of homes that use a heat pump for space heating increases from approximately 13% to 60% (see Figure 3-1). The share of non-electric commercial buildings decreases from approximately 70% in 2020 to 5% in 2050. The SES assumes electrification in the commercial sector relies upon the increased use of both electric resistance and heat pumps while electric resistance is phased out in the residential sector.

Figure 3-1. 2021 Washington State Energy Strategy Space Heating Technology Mix[22]



In this study, E3's modeling of the building stock uses the same trajectory of fuel conversions as the SES. This analysis assumes that the non-electric share of the residential housing stock will be 20% and the non-electric share of the commercial building stock will be 5% in 2050 consistent with the SES. Unlike the SES, however, E3 assumes that the current commercial electric resistance building stock will remain not increase. Rather, E3 assumes the heat pumps will be used in new construction and retrofits of existing fuel buildings. Sales for new construction are assumed to be 100% heat pumps by 2030 and the building stock is expected to grow at 1% each year.

Figure 3-2 Statewide space heating technology mix modeled

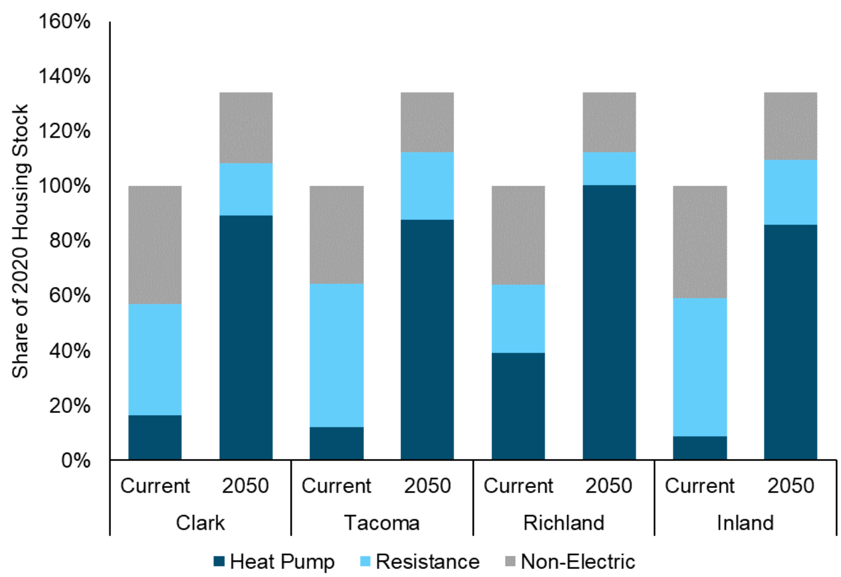


The statewide fuel conversion and resistance phaseout rates were applied to all COUs through 2050, but because the starting share of space heating technology mix of each COU's service area differs, the 2050

[22] *2021 Washington State Energy Strategy, Chapter D, pg. 69.* https://www.commerce.wa.gov/wp-content/uploads/2021/01/WA_2021SES_Chapter-D-Buildings.pdf

space heating technology mix modeled in each territory differs. County level data from the U.S. Census Bureau's American Community Survey served as the basis for determining the residential current space heating technology mix in the service territories for Clark PUD, Tacoma Power, and IPL. Richland Energy Services provided space heating technology mix data for their service territory for this analysis. The share of non-electric homes is similar between the COUs, ranging from 36-43% of the existing stock, suggesting that difference in load growth between COUs will be driven by variation in climate and the efficiency of the building stock. The share of current resistance customers is largest in Tacoma and Inland, indicating that the electric resistance phaseout in these utilities will have a larger impact on mitigating system impacts.

Figure 3-3 Residential Space Heating Technology Mix by COU. Bar charts exceed 100% in 2050 following statewide population growth trends.



3.2.2 RESHAPE Model Description

E3's RESHAPE model is designed to simulate diversified system-level building electrification load shapes. System diversity is captured in the model through a regionally specific sample of buildings representing the housing stock and space heating technology mix, temporal and spatial variability in temperature, and the mix of heat pump technologies adopted. Building stock data is sourced from the U.S. Energy Information Agency (EIA) Residential Energy Consumption Survey (RECS) and Commercial Buildings Energy Consumption Survey (CBECS) and was adjusted for each COU's territory based on data provided by the utilities and E3's industry knowledge. To capture the impact of weather of on building electrification loads, E3 modeled system and building loads under 40 years of historical weather to assess a 1-in-2, or median weather year, system impact and a 1-in-10, or 90th percentile, system impact. The RESHAPE model was run with county-level resolution and scaled to each utility's territory as described in Table 3-1. RESHAPE models various standard, mid, and best-in-class performance all-electric heat pumps as well as dual-fuel hybrid heat pumps. Heat pump performance data is sourced from manufacturer reported data provided by the Northeast Energy Efficiency Partners (NEEP) in its *Cold Climate Air Source Heat Pump Product List and Specifications* (see Table 3-2). Heat pump efficiency and capacity is modeled as a function of outdoor air temperature in each hour. Thus, the achieved COP varies between COUs (see Table 3-3) due to differing climates and model calibration for each territory. Detailed assumptions on heat pump performance and sizing assumptions can be found in Section 5.2. The mix of heat pump technology is varied between scenarios modeled as described in Section 3.3.

Table 3-1. Spatial representation of COUs in RESHAPE

COU	Representative County
Clark Public Utility District	Clark
Tacoma Power	Pierce
Richland Energy Services	Benton
Inland Power and Light	Spokane

Table 3-2 NEEP Coefficient of Performance (COP) of Heat Pumps Data

Heat Pump Performance	COP @ 5°F	COP @ 17°F	COP @ 47°F
Standard Performance	1.75	2.00	3.00
Mid Performance	2.36	2.65	4.00
Best-in-Class Performance	2.9	3.30	5.00

Table 3-3 Achieved Coefficient of Performance (COP) of Heat Pumps Adopted in Retrofit applications

Heat Pump Performance	COU	Annual Average COP	
		Residential	Commercial
Standard Performance	Tacoma	2.3	1.8
	Inland	1.3	1.9
	Clark	2.5	2.4
	Richland	2.7	1.9
Mid Performance	Tacoma	3.1	2.4
	Inland	1.7	2.5
	Clark	3.3	3.2

	Richland	3.5	2.2
Best-in-Class Performance	Tacoma	4.0	3.1
	Inland	2.3	3.4
	Clark	4.1	4.0
	Richland	4.6	2.6

3.2.2.1 Simulation of Historical Baseload

E3's analysis of the electrification load impact considers 40 years of historical weather conditions to determine 1-in-2 and 1-in-10 peak load impacts. E3's RESHAPE model simulates 40 years of incremental heat pump load. In addition, 40-years of weather-matched base system load profiles are needed to estimate total system load impacts from electrification, but those are not available from COUs' historical record. Therefore, E3 simulated existing hourly loads for the 40 years of weather conditions for each utility using a neural network regression model. Using recent historical load data provided by the COUs, the neural network regression model was trained using minimum and maximum daily temperature in the county representing each COU and date factors (e.g., day of week, calendar date) as inputs to predict daily load. The predicted daily load was transformed to hourly load based on the shape of the historical observed day that had the most similar total daily load within a two-week window of each day. This method for simulating baseload is used by E3 in resource planning and resource adequacy analyses across the U.S. The 40 years of simulated baseload were combined with 40 years of building electrification load shapes generated by E3's RESHAPE model to assess the impacts of electrification in a typical and extreme weather year.

3.3 Scenario Design

E3 developed seven scenarios that explore how heat pump performance impacts incremental load, how the use of backup heating fuels mitigates peak load growth, and how investments in efficiency can reduce system impacts (see Table 3-4). The base case is characterized by the adoption of mid performance all-electric heat pumps in retrofit applications and new construction. In all scenarios, E3 assumed that current resistance customers adopting heat pumps receive best-in-class, high performance heat pumps, consistent with replacement with ductless mini-split systems. All heat pumps modeled are assumed to meet the NEEP Cold Climate Product Specification. This means that each scenario assumes consumers adopt high efficiency heat pumps that exceed current Federal minimum standards and do not completely switch to electric resistance heat during cold conditions.

- Heat pump performance: The **Standard HP** scenario considers how the adoption of lower performance cold-climate heat pumps could increase load growth while the **Best-in-Class HP** scenario highlights how investments in high performance heat pumps and improving heat pump sizing practices can mitigate load growth (see Table 3-2 for details on heat pump performance).

- Efficiency: The **Tight Shell** scenario considers how retrofitting the entire building stock's envelopes up to new construction standards could mitigate load growth. Given the significant ambition of the Tight Shell scenario in both its scope, costs and technical feasibility, E3 also explored a Moderate Shell scenario in which all existing buildings were assumed to receive a less intensive shell upgrade to show a more likely outcome of load management strategies focused on shell improvements (see Section 5.6). The **Electric Resistance Phaseout** scenario considers the complete elimination of resistance heating in the residential building stock by 2050 to illustrate the impact of a demand management strategy targeting this segment for heat pump adoption (see section for stock rollover assumptions 0).
- Dual-Fuel heat pumps: The **Hybrid** scenario models the adoption of dual-fuel heat pumps by current residential and commercial fuel customers to explore how the use of fuel to serve heating demand in the coldest hours mitigates peak load impacts. The **Commercial Hybrid** scenario considers the adoption of hybrid heat pumps in the commercial sector and all-electric heat pumps in the residential sector. The exploration of the Commercial Hybrid scenario was motivated by Task 2 findings that dual-fuel heat pumps in the commercial sector are more cost-effective than all-electric heat pumps from the customer's perspective when they face demand charges. In both hybrid scenarios, the dual-fuel heat pumps are assumed to be ducted heat pumps such that the when the heat pump cannot serve the full load, the heat pump will be locked out and the back-up combustion system takes over.

These scenarios are designed to be distinct such that they highlight the potential of certain load management strategies on mitigating system impacts. In practice, a combination of strategies would likely be deployed to manage system impacts based on factors including cost-effectiveness and customer preferences. As an example of such a portfolio, E3 modeled a Peak Mitigation scenario, which combines the strategies used in Commercial Hybrid, Best-in-Class HP, and Electric Resistance Phaseout scenarios, and is discussed in the Appendix (see section 5.7).

Figure 3-4 and Figure 3-5 show the share of adopted heat pumps by technology type in each scenario In the base case, 30% of heat pumps adopted are from current resistance customers switching to best-in-class heat pumps and 70% of heat pumps adopted are mid performance heat pumps from fuel switching and in new construction. Since E3 assumes that heat pump adoption occurs only in retrofits of existing fuel customers and new construction in the commercial sector, 100% of heat pumps adopted by 2050 in the Base Case scenario are mid performance. In the Hybrid scenario, existing residential and fuel customers adopt dual-fuel heat pumps while existing residential resistance customers adopt all-electric heat pumps. In the Commercial Hybrid scenario, the residential sector adopts all-electric heat pumps consistent with the Base Case scenario while the commercial existing fuel customers adopt dual-fuel heat pumps.

Figure 3-4 Residential mix of heat pump technology types

Figure 3-5 Commercial mix of heat pump technology types

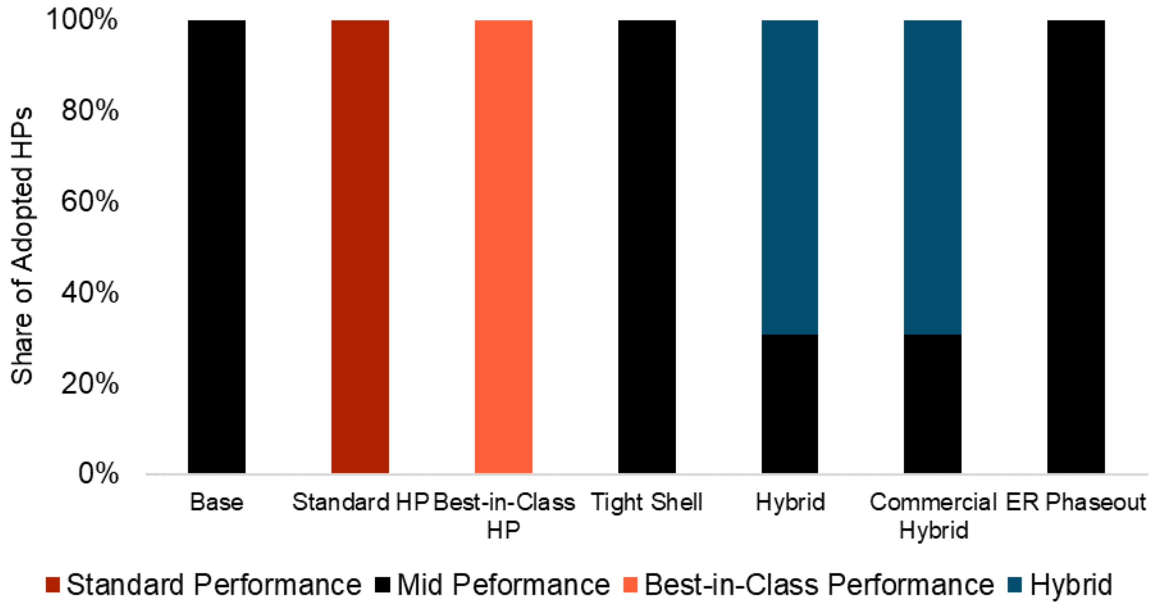


Table 3-4. System Impact Scenario Table. Unique input assumptions to each scenario are highlighted in bold.

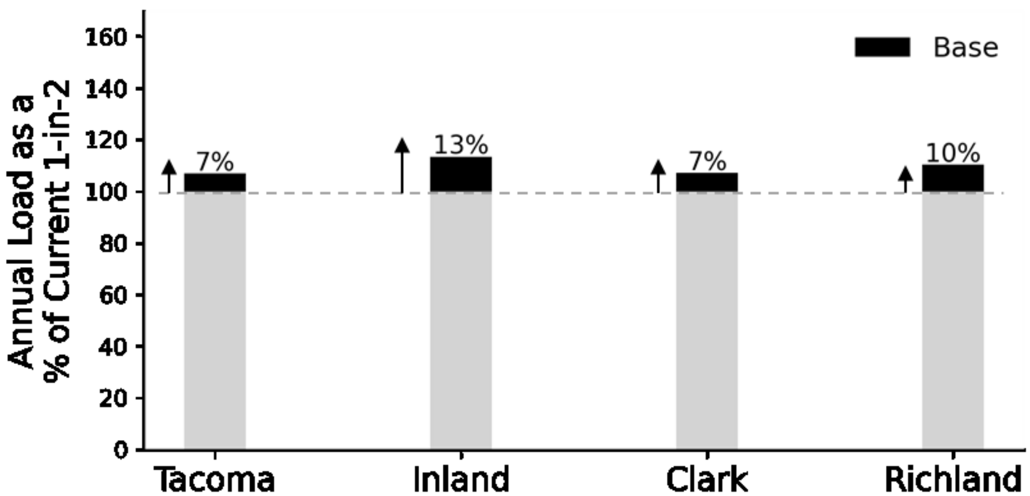
	Base Case	Standard HP	High Efficiency	Tight Shell	Hybrid	Commercial Hybrid	Electric Resistance Phase Out
Heat Pump Performance	ccASHPs are 100% mid performance	**ccASHPs are 100% standard performance**	**ccASHPs are 100% high performance**	ccASHPs are 100% mid performance	Dual-Fuel HPs and ccASHP are 100% mid performance		ccASHPs are 100% mid performance
Heat Pump Sizing	ASHPs sized at to a heat pump balance point temperature of 20°F		**ASHPs are oversized**	ASHPs sized at to a heat pump balance point temperature of 20°F	**ASHPs sized at to a heat pump balance point temperature of 30°F**		ASHPs sized at to a heat pump balance point temperature of 20°F
Backup Fuel	Residential and commercial customers rely on electric resistance in coldest hours				**Residential and commercial customers rely on fuel in coldest hours**	**Residential relies on electric resistance and commercial customers rely on fuel in coldest hours**	Residential and commercial customers rely on electric resistance in coldest hours
Building Shell Improvements	New construction built with a tight shell; Existing building stock does not retrofit shells			**The entire building stock has a tight shell**	New construction built with a tight shell; Existing building stock does not retrofit shells		
Today's fuel customers	Adopt All-Electric ASHP				Adopt Dual Fuel HPs		Adopt All-Electric ASHP
Today's Electric Resistance Customers	~50% of current residential electric resistance customers adopt all-electric heat pumps consistent with the SES						**All current resistance customers adopt heat pumps**

3.4 Key Results

3.4.1 Base Case results for all COUs

Electrification is expected to lead to modest increases in annual electricity sales in all utilities by 2050 due the high annual efficiencies of heat pumps and the transition away from electric resistance heating in the residential sector. Tacoma Power and Clark PUD see similar annual energy sales growth—approximately 7% of the current 1-in-2 annual system load—due to similar climate and building stock. Inland sees the highest annual energy sales growth with the electrification of heating due to its colder climate.

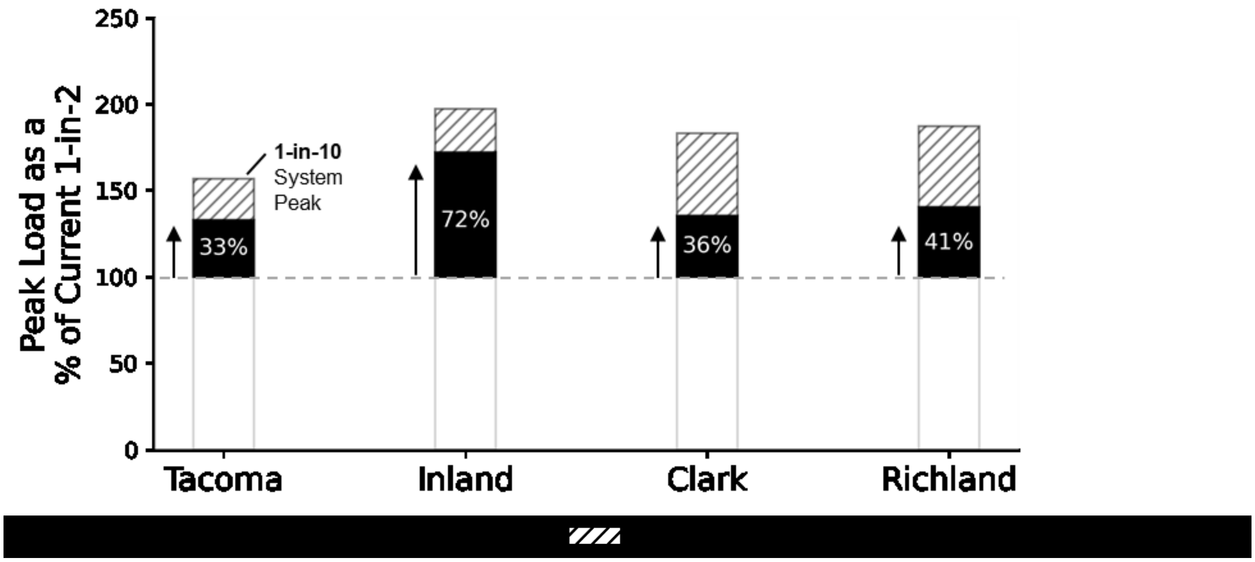
Figure 3-6 Annual energy sales Growth (1-in-2) for Base Case Scenario by 2050



E3 found that the peak load impacts from electrification are expected to be substantially larger than the annual energy sales impact due to the reduced efficiency of heat pumps in colder weather. Figure 3-7 shows peak demand impacts under both 1-in-2 and 1-in-10 peak conditions. During an extreme cold weather event in the 1-in-10 weather year, peak load impacts are expected to be even larger than the 1-in-2 peak impact due to the reduced capacity and efficiency of the compressor of a heat pump during cold events as well as the greater reliance on supplemental electric resistance heat.

Tacoma Power and Clark PUD are expected to have similar 1-in-2 peak load growth, but the expected 1-in-10 peak load growth in Clark PUD is much larger due to underlying interannual variability in baseload and existing morning peak coincident with incremental building loads. Inland and Richland show higher peak load growth due to their colder climate.

Figure 3-7 Peak Load Growth for Base Case Scenario by 2050



3.4.2 Clark PUD Scenario Results Comparison

Figure 3-8 and Figure 3-9 show the annual energy sales impact and peak impact load impact for Clark PUD for all the core scenarios modeled. The results indicate that utilities can leverage various measures to mitigate system impacts from building electrification.

Heat pump efficiency improvements could have large impacts reducing both annual and peak loads. The **Standard HP** scenario illustrates how using lower performance cold-climate heat pumps could increase system impacts compared to the **Base Case** scenario. The **Best-in-Class** scenario shows that annual energy sales impacts could be reduced by approximately 29% and peak load impacts could be reduced by 50% compared to the Base Case scenario by using the highest-efficiency models available on the market in all segments as well as sizing heat pumps to serve the full heating load which avoids the need to resistance heating in the coldest hours. The increased sizing of heat pumps in the Best-in-Class scenario reduces the spread between the 1-in-2 and 1-in-10 peak observed in the Base Case. Importantly, the heating systems modeled in the Best-in-Class scenario come at a cost premium and would likely require changes in contractor practices related to the sizing of heat pump equipment.

The **Tight Shell** scenario shows that upgrading all existing buildings to meet the envelope standards of the latest Washington building code could reduce annual and peak load impacts by approximately 25-30%. The ambition of the Tight Shell scenario is high in both its scope and technical feasibility as it assumes the entire building stock would be brought up to current code by 2050. To bring an existing building up to the current code, the wall insulation would have to more than double, glazing performance would need to quadruple, and infiltration would need to be reduced by 75%. In E3's experience the cost of such a retrofit, although not evaluated in this study, would likely outweigh the bill savings a customer would achieve. Thus, E3 explored a Moderate Shell scenario that considers a less extensive set of interventions. The details of the Moderate Shell scenario are discussed further in Section 5.6

The **Electric Resistance Phaseout** scenario illustrates the impact of replacing all electric resistance heating with heat pumps in the residential sector. Annual energy sales impacts in Clark PUD decrease by 57% while peak load impacts decrease by 33%. Impacts on annual energy sales are greater than the peak load since heat pump performance declines in the coldest hours, but since the resistance to heat pump conversions are assumed to adopt best-in-class heat pumps sized to the full load, peak load impacts could still be mitigated significantly with this strategy. Like the shell retrofits, this strategy likely faces its own feasibility challenges, including the higher upfront costs of heat pumps and the fact that many electric resistance customers in Washington are tenants.

In the **Commercial Hybrid** scenario, the adoption of dual-fuel heat pumps in the commercial sector has a small impact on mitigating annual energy sales growth but the 1-in-2 peak load impact decreases by 42% compared to the Base Case scenario. In this scenario, heat pumps still serve a majority of the load, but the reliance on supplemental fuel in the hours below 30°F decreases peak load impacts. With the adoption of dual-fuel heat pumps in both residential and commercial retrofits in the **Hybrid** scenario, the 1-in-2 peak load impacts are 55% lower than the Base Case scenario. The use of dual-fuel heat pumps reduces the difference between the 1-in-2 and 1-in-10 system peak as the use of supplemental fuel minimizes variation in the heating demand served by the electric system between years. In the Hybrid scenario, the difference in the 1-in-2 and 1-in-10 peak load is driven by electric resistance load remaining on the system and all-electric best-in-class heat pumps adopted by those current resistance customers who adopt heat pumps.

Figure 3-8. Clark PUD Annual Energy Sales Growth in 2050

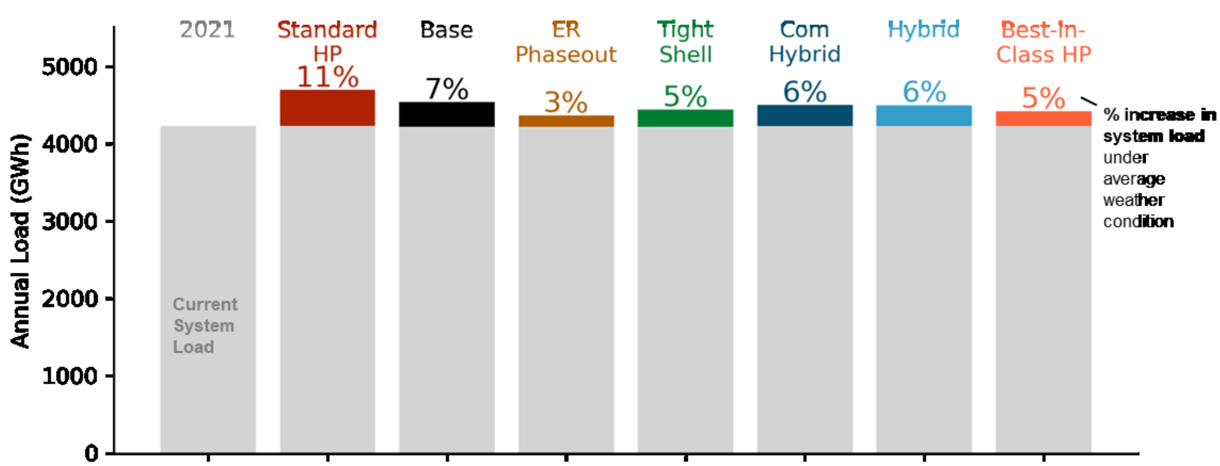
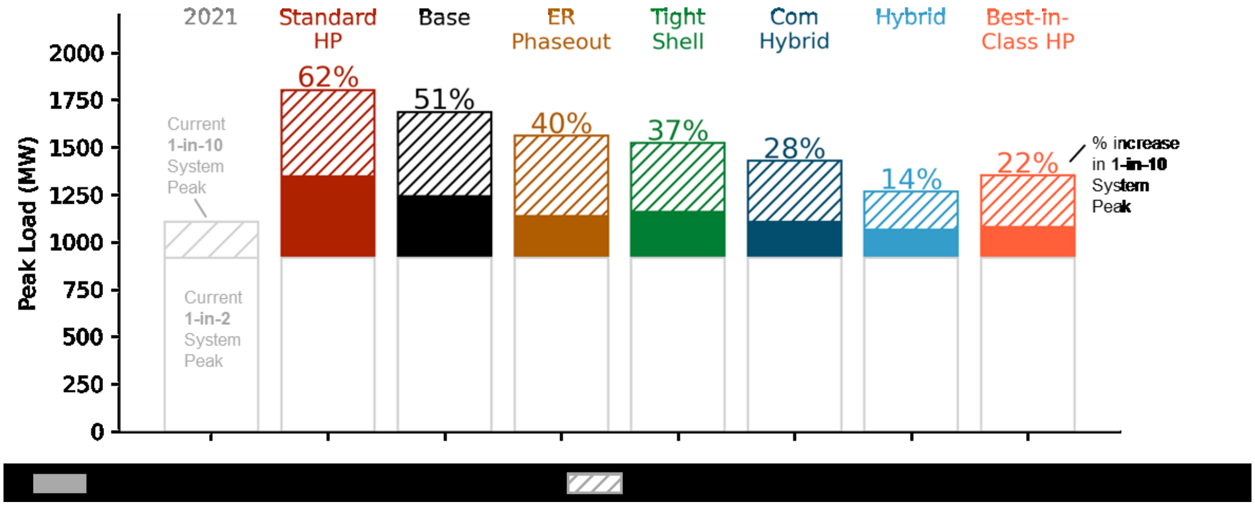


Figure 3-9. Clark PUD 1-in-2 and 1-in-10 Peak Load Growth in 2050 (% growth in 1-in-10 peak load labeled)



The load management strategies explored in each scenario generally have consistent impacts compared to the Base Case scenario across all COUs. Results for each scenario and utility are reported below in Table 3-5, Table 3-6, and Table 3-7 and are presented in more detail in the Appendix.

Table 3-5. 1-in-2 Peak Load Growth by 2050

	Base	Standard HP	Best-in-Class HP	Tight Shell	Hybrid	Commercial Hybrid	ER Phaseout
Clark PUD	36%	47%	18%	27%	16%	21%	24%
IPL	72%	81%	28%	56%	14%	32%	42%
RES	41%	49%	18%	32%	15%	20%	15%
Tacoma Power	33%	44%	12%	15%	8%	10%	14%

Table 3-6. 1-in-10 Peak Load Growth by 2050

	Base	Standard HP	Best-in-Class HP	Tight Shell	Hybrid	Commercial Hybrid	ER Phaseout
Clark PUD	51%	62%	22%	37%	14%	28%	40%
IPL	76%	85%	31%	60%	20%	36%	47%
RES	51%	59%	23%	42%	13%	25%	25%
Tacoma Power	44%	55%	17%	29%	7%	15%	34%

Table 3-7 Annual Energy Sales Growth by 2050

	Base	Standard HP	Best-in-Class HP	Tight Shell	Hybrid	Commercial Hybrid	ER Phaseout
Clark PUD	7%	11%	5%	5%	6%	6%	3%
IPL	13%	18%	9%	11%	9%	10%	5%
RES	10%	14%	8%	9%	9%	10%	3%
Tacoma Power	7%	10%	5%	5%	6%	6%	4%

3.5 Key Conclusions

In all COUs, annual energy sales impacts from building electrification at the scales envision in the SES are expected to be modest, but peak load impacts could be significant by 2050. E3 found that building electrification increases peak electric load by 3-10% by 2030 and 30-70% by 2050 for the four studied COUs, while annual electricity sales will only increase by ~10% by 2050. Peak load impacts are expected to be more significant than annual energy sales impacts as electrification adds to existing peak load in all COUs and the performance of heat pump declines in colder hours.

The analysis shows that utilities could leverage various intervention measures to alleviate peak load impacts from electrification. Measures include:

- **High-efficiency heat pump models:** the Best-in-Class HP scenario illustrates that deploying high performance heat pumps and sizing the compressor to be able to serve the full load has significant potential to mitigate peak load impacts due to higher COPs at cold temperature and the avoidance of backup electric resistance heating. The heat pumps modeled in this scenario would come at a cost premium and would require changes to current contractor practices for sizing heating equipment. Despite this, the deployment of best-in-class heat pumps is more likely to happen at scale than the shell improvements modelled in the Tight Shell scenario due to the significant costs and technical limitations associated with a deep shell retrofits that bring existing buildings up to new construction standards. The Benefit Cost Analysis found that customers are more likely to adopt base performance heat pumps than best-in-class heat pumps due the significant cost premium that outweighs bill savings and that the cost premium is greater than the electric system cost savings from the higher performance system. Thus, market transformation that reduces the cost of high-efficiency heat pumps will be important for reducing both consumer and electric system costs.
- **Replacement of electric resistance heating with more efficient heat pump HVAC systems:** the analysis found that targeting the phaseout of electric resistance heating can also help mitigate system load impacts. While the Electric Resistance Phaseout scenario generally had the lowest annual energy sales growth across all scenarios, the Best-in-Class HP and hybrid scenarios were

generally more effective at reducing peak load impacts. Though not modeled in the benefit cost analysis, switching from electric resistance to heat pumps is generally more cost effective for customers. Thus, this strategy would likely face lower financial barriers for deployment at scale.

+ **Building shell improvements:** moderate shell improvements that target improving roof insulation and reducing infiltration could be less cost-prohibiting compared to deep shell retrofits but still effective at reducing system peak loads. Further investigation into costs of shell upgrade would be needed to determine its cost-effectiveness for specific applications.
+ **Dual-fuel heat pump HVAC systems:** the Hybrid and Commercial Hybrid scenarios illustrate that the deployment of dual-fuel heat pumps can significantly reduce peak load impacts while still providing most of the carbon reduction benefits of electrification. The deployment of dual-fuel heat pumps also reduces the difference between the 1-in-2 and 1-in-10 peak load compared to scenarios relying upon all-electric heat pumps, which can provide utility planners more certainty and reduce the cost of maintaining reliability of both the gas and electric systems. The benefit cost analysis indicates that existing electric rate structures that contain demand charges make the adoption of dual-fuel heat pumps more favorable, but other rate designs and technology options such as demand response could make the adoption of heat pumps more cost effective by reducing bills and mitigating system peak load impacts.

While assessing costs for the utility associated with the load management strategies modeled in the system impacts analysis was outside the scope of this study, results from the benefit cost analysis indicate that ratepayer funds are likely to be limited to support electrification and load management strategies. However, the analysis indicates that with market transformation and policy support, electric system impacts from electrification can be effectively mitigated.

4 Discussion and Recommendations

The Benefit Cost Analysis of this study identifies several near-term opportunities where electrification is cost-effective, but also identifies large segments of the state's existing building stock where electrification comes at a large upfront cost premium. Based on the key findings from the Benefit Cost Analysis, **E3 provides the following recommendations to improve the cost-effectiveness of building electrification:**

1. **Incentivize all-electric new construction.** All-electric new construction is cost-effective in all cases considered in this report.
2. **Target heat pump HVAC at customers that need new air conditioners and those currently relying on fuel oil or propane for heating.** These customers have the lowest costs among the retrofit opportunities considered in this study.
3. **Provide subsidies to lower the incremental consumer costs of electrification.** In cases where utility revenues from additional sales exceed the incremental costs of electrification, incremental consumer costs could be partially funded by ratepayer funds. However, non-ratepayer sources of funding will be needed to make electrification cost-effective for customers without negatively impacting non-participants.

4. **Ensure efficient price signals are conveyed in electric and natural gas rates.** Design more efficient electricity rates, including time varying rates, that align prices with system costs. For example, results from this work indicate commercial demand charges shift customer economics towards dual-fuel heat pumps, which at scale would have the lowest impact on the COU's peak demands. More efficient rates could encourage the adoption of higher-efficiency heat pumps and dual-fuel heat pumps that alleviate load impacts from electrification and cost burdens on the electric system. Policies aimed at reducing the GHG emissions from natural gas would also better align customer's economic incentives with the state's climate goals and make electrification more cost effective.

Benefit Cost Analysis results are sensitive to some key assumptions, including:

- Upfront capital cost are case specific, as demonstrated by the "full A/C cost" case. Market penetration and learning by doing may further lower HP costs as adoption increases
- Electricity supply cost could be lower if considering current customers switch from electric resistance to heat pumps, which will help mitigate the peak impact.
- Heat pump performance could improve over time and thus increase customer savings.
- Gas rates could be different and may become higher if building electrification materializes, and fewer customers are staying on the gas grid, especially the delivery component of the rates. This analysis assumes current ratemaking with historical escalation of gas delivery rate.
- Avoided gas infrastructure cost could provide savings in a high electrification future. This analysis currently assumes none.
- Public health benefits are not included. This is an important factor to consider for the benefits of electrification.

Benefit Cost Analysis results indicate that standard HPs with base performance are most likely to provide participant benefits due to their lower cost compared with cold climate HPs and dual-fuel HPs. Although standard HPs consume more energy and are more expensive to operate, the benefit of lower upfront costs outweighs the higher cost of energy. In addition, residential rates are not reflective of the marginal system costs to serve the increased load, especially during system peak periods. Therefore, customers may adopt systems that have large system impacts rather than higher-efficiency cold-climate heat pumps or dual-fuel heat pumps that can help alleviate load impacts during peak periods in winter.

Peak Load Impact Analysis results suggest that electrifying buildings with only standard HPs could result in significant increase in electric peak demand up to 70% by 2050. **To alleviate the peak load impact from building electrification, E3 recommends that utilities could implement the following intervention measures:**

1. **Support market transformation of high-efficiency heat pump models to reduce their cost premiums**. Utilities could subsidize high-efficiency heat pump models to further provide incentives for customer adoption. Utilities should also consider partnering with manufacturers to incentivize research, development and commercialization of high-efficiency cold-climate heat pump products, and push for market transformation to achieve cost reduction via economies of scale.

2. **Target replacement of electric resistance heating with more efficient heat pump HVAC systems.** A complete phase-out of resistance heating is found to reduce peak load impact from electrification by more than 30%, compared to what is envisioned in the 2021 Washington State Energy Strategy.
3. **Incentivize shell improvements for older buildings.** Moderate shell improvements that target improving roof insulation and reducing infiltration could be less cost-prohibiting compared to deep shell retrofits but still effective at reducing system peak loads. Further investigation into costs of shell upgrade would be needed to determine its cost-effectiveness for specific applications.
4. **Leverage demand response (DR) programs to help lower the peak system load and electric bills for commercial customers.** A DR sensitivity conducted in this study found that by expanding the thermostat setpoints of office buildings by 3 °F during the system peak hours, peak heating demand could be lowered by as much as 20%. Further assessment for the technical feasibility and costs of DR programs are needed to determine what is feasible for utilities to implement.
5. **Encourage customers to install dual-fuel heat pump HVAC systems.** Peak Load Impact Analysis found that installing dual-fuel systems in commercial buildings alone could reduce peak load impact from electrification by more than 50% compared to all-electric systems. Utilities may design more efficient rates or programs that would align price signals with system costs and savings and make dual-fuel heat pumps cost effective.

This study also suggests it is important for policymakers and utilities to carefully design policies to support the large infrastructure needs for building electrification and potential high capital investments. Achieving building electrification at the scales envisioned in the Washington State Energy Strategy will require a robust ecosystem, including supply chains and skilled labor. Building a sufficient amount of electric infrastructure will similarly require substantial new construction activities by the state’s electric utilities.

5 Appendix

5.1 Building Simulation Descriptions

Energy profiles for each customer were calculated using prototype EnergyPlus simulations as described in Table 5-1 Prototype EnergyPlus Models. Each prototype model was selected based on the building stock characterization described below. Building retrofits were modeled with envelope characteristics and representative of the existing building stock, while new construction was modeled with envelope characteristics meeting the latest approved Washington state energy code requirements, as described in Table 5-2 Envelope Inputs for EnergyPlus Models. Both retrofits and new construction were modeled with systems that meet the latest approved Washington state energy code requirements, as described in Table 5-3 System Inputs for EnergyPlus Models.

Table 5-1 Prototype EnergyPlus Models

Model Type	Size	Occupancy
Single-Family Residential	2,300 sq ft	3 ppl
Multi-Family Residential	1,000 sq ft	2 ppl
Commercial Retail	5,000 sq ft	75 ppl
Small Commercial Office	10,000 sq ft	50 ppl
Large Commercial Office	138,000 sq ft	700 ppl
Small Commercial Healthcare	18,000 sq ft	175 ppl
Large Commercial Healthcare	415,000 sq ft	4,000 ppl

Table 5-2 Envelope Inputs for EnergyPlus Models

Envelope Component	Retrofit	New Construction
Wall Insulation	R-11	R-18
Roof Insulation	R-15	R-38
Infiltration Rate	0.22 cfm/sq facade	0.05 cfm/sq facade
Glazing SHGC	0.40	0.30
Glazing U-Value	U-1.20	U-0.30 (Res), U-0.50 (Comm)

Table 5-3 System Inputs for EnergyPlus Models

System Component	Residential	Commercial
Distribution	Ductless Packaged Units	VAV Reheat (Retrofit) Dedicated Outdoor Air System w/ Fan Coils (NC)
Cooling	12.0 SEER Packaged AC Unit	17.0 SEER Chiller
Heating	80% eff Gas Packaged Unit	80% eff Gas Boiler

Hot Water	80% eff Gas Tanked WH	80% eff Gas Tanked WH
Cooking	80% eff Gas Cooktop	-

5.2 Building Stock Characterization

5.2.1 Representative Residential Building Types

E3 utilized the EIA RECS database to identify a range of residential building types that together represented roughly 95% of the residential building stock in the study geography by number of households. This study focused only on households that used gas or a delivered fuel (e.g. liquid propane gas) as a space heating fuel.

Table 5-4 Building Stock Representation of Residential Building Types

IECC Zone	Segment	SH Fuel	AC	Share of Stock (%)	Share of energy (%)
4C	Single Family	Gas	AC	45%	47%
5B-5C	Single Family	Gas	AC	27%	25%
4C	Single Family	Gas	No AC	13%	11%
4C	Single Family	Delivered Fuel	No AC	8%	8%
4C	Single Family	Delivered Fuel	AC	3%	4%
5B-5C	Single Family	Gas	No AC	3%	4%
5B-5C	Multifamily	Gas	AC	1%	1%

Table 5-5 Energy Use Characteristics of Residential Building Types

IECC Climate Zone	Segment	SH Fuel	AC	Median Area (ft2)	Total Energy Use (kBtu/yr)	Total EUI (kBtu/ft²)	SH Energy Use (kBtu/yr)	SH EUI (kBtu/ft²)
4C	Single Family	Gas	AC	2,281	95,058	42	40,454	18
5B-5C	Single Family	Gas	AC	1,623	83,961	52	46,164	28
4C	Single Family	Gas	No AC	2,305	70,334	31	35,692	15
4C	Single Family	Delivered	No AC	2,965	90,646	31	43,994	15
4C	Single Family	Delivered	AC	3,730	130,962	35	60,039	16
5B-5C	Single Family	Gas	No AC	2,235	120,768	54	85,020	38
5B-5C	Multifamily	Gas	AC	1,042	87,401	84	21,278	20

5.2.2 Representative Commercial Building Types

E3 utilized the EIA CBECS database to identify a range of commercial building types that together represented roughly 80% of the commercial building stock in the study geography by floorspace.

Table 5-6 Building Stock Representation of Commercial Building Types

BA Climate	HVAC Equipment	Primary Use	Share of Area (%)	Share of Energy Use (%)
Cold	Packaged Unit	Retail	19%	22%
Marine	Packaged Unit	Retail	12%	16%
Marine	Packaged Unit	Office	13%	11%
Marine	Boiler/Chiller	Office	11%	11%
Cold	Packaged Unit	Office	7%	8%
Marine	Boiler/Chiller	Healthcare	3%	7%
Cold	Packaged Unit	Healthcare	2%	3%

Table 5-7 Energy Use Characteristics of Commercial Building Types

BA Zone	HVAC	Primary Use	Median Area (ft^2)	Total Energy Use (kBtu/yr)	Total EUI (kBtu/ft^2)	SH Energy (kBtu/yr)	SH EUI (kBtu/ft^2)
Cold	Packaged Unit	Retail	5,000	2,796,174	559	718,539	29
Marine	Packaged Unit	Retail	5,400	2,039,777	378	431,601	29
Marine	Packaged Unit	Office	3,900	1,318,813	338	368,616	23
Marine	Boiler/Chiller	Office	138,000	15,941,849	116	4,291,440	25
Cold	Packaged Unit	Office	11,000	1,793,416	163	496,288	31
Marine	Boiler/Chiller	Healthcare	415,000	137,138,490	330	52,984,778	102
Cold	Packaged Unit	Healthcare	18,000	3,608,566	200	1,306,484	40

5.3 Technology Specifications

5.3.1 Modeling Heat Pump HVAC Systems

HVAC systems were sized for each building type to 99.6% of heating or cooling load, modified by an oversizing factor of 25% for heating and 10% for cooling. E3 applied an additional safety factor of 30% to account for the differences between a typical (1 in 2) weather year and a 52 heating degree day year. E3 calculated system sizes for both heating and cooling and selected the larger of the two to use for cost estimations and further modeling.

Because heat pumps draw on latent energy in ambient air, their efficiencies vary with outdoor temperature. Heating efficiencies drop, though remain above 1.0, as temperature declines. Modeling reflects this decline as a percentage deration of the heat pump's maximum efficiency across a range of temperatures. The efficiency curves for all heat pumps considered in this work were aligned with E3's previous work on the California Building Electrification Study. Residential HVAC CAPEX costs were sourced from E3's prior work on building electrification in California.[23]

Rated efficiencies assumed for space heating and space cooling across residential and commercial buildings are summarized in the tables below.

Table 5-8 Rated Efficiency Assumptions, Space Heating

Technology	Residential (kBtu/kBtu)	Commercial (kBtu/kBtu)
Ducted ASHP	2.93	2.93
Ducted Cold Climate ASHP	3.81	3.81
Gas Furnace, Traditional + AC	0.80	0.80

Table 5-9 Rated Efficiency Assumptions, Space Cooling

Technology	Residential (kBtu/kBtu)	Commercial (kBtu/kBtu)
Ducted ASHP	5.27	5.27
Ducted Cold Climate ASHP	6.15	6.15
Gas Furnace, Traditional + AC	4.10	4.10

Balance point temperatures and system sizes assumed for residential and commercial buildings are summarized in the tables below.

Table 5-10 Residential Balance Point Temperatures and System Sizes

Building Type	CZ	Vintage	BP Temp (ºF)	HVAC Equipment Size (tons)				
				Gas Furnace	AC Unit	Standard ASHP	ccASHP	Dual-Fuel ASHP
Single Family Res	CZ4C	NC	68.1	2.5	1.0	1.3	1.3	1.3
		Retrofit	70.4	3.3	1.5	2.1	2.1	1.7
	CZ5B	NC	65.8	4.2	1.5	2.1	2.1	1.7
		Retrofit	67.5	5.4	2.0	3.3	3.3	2.5
Multifamily Res	CZ5B	NC	65.4	1.7	1.0	1.0	1.0	1.0
		Retrofit	66.5	2.1	1.0	1.0	1.0	1.0

[23] Energy and Environmental Economics, 2019, "Residential Building Electrification in California", https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

Table 5-11 Commercial Balance Point Temperatures and System Sizes

Building Type	CZ	Vintage	BP Temp (°F)	HVAC Equipment Size (tons)					
				Gas Packaged Unit	Chiller	Boiler	Standard ASHP/ W2WHP	ccASHP/ W2WHP	Dual-Fuel ASHP/ W2WHP
Small Office	CZ4C	NC	64.7	9.0	-	-	9.0	9.0	9.0
		Retrofit	67.0	10.0	-	-	10.0	10.0	10.0
	CZ5B	NC	62.3	13.3	-	-	10.0	10.0	10.0
		Retrofit	65.4	15.0	-	-	12.0	12.0	12.0
Small Retail	CZ4C	NC	58.9	9.0	-	-	9.0	9.0	9.0
		Retrofit	63.8	9.0	-	-	9.0	9.0	9.0
	CZ5B	NC	69.4	11.7	-	-	10.0	10.0	10.0
		Retrofit	75.2	13.3	-	-	10.0	10.0	10.0
Small Healthcare	CZ4C	NC	N/A	52.0	-	-	52.0	52.0	52.0
		Retrofit		52.0	-	-	52.0	52.0	52.0
	CZ5B	NC		48.0	-	-	48.0	48.0	48.0
		Retrofit		55.0	-	-	54.0	54.0	54.0
Large Office	CZ4C	NC	64.7	-	112.5	120.0	120.0	120.0	120.0
		Retrofit	67.0	-	137.5	130.0	130.0	130.0	130.0
	CZ5B	NC	62.3	-	175.0	140.0	140.0	140.0	140.0
		Retrofit	65.4	-	204.2	160.0	160.0	160.0	160.0
Large Healthcare	CZ4C	NC	N/A	-	1,104.2	1,160.0	1,160.0	1,160.0	1,160.0
		Retrofit		-	1,095.8	1,170.0	1,170.0	1,170.0	1,170.0
	CZ5B	NC		-	987.5	1,100.0	1,100.0	1,100.0	1,100.0
		Retrofit		-	1,241.7	1,240.0	1,240.0	1,240.0	1,240.0

5.3.2 Modeling Heat Pump Water Heaters

Rated efficiencies for each water heating equipment type modeled in the present study are summarized below.

Table 5-12 Rated Efficiency Assumptions, Water Heating

Equipment Type	Residential (kBtu/kBtu)	Commercial (kBtu/kBtu)
Heat Pump Water Heater	4.00	-
Gas Storage Water Heater	0.62	-
Gas Tankless Water Heater	0.75	-

5.4 Additional Benefit Cost Analysis Results

5.4.1 Single-Family Residential Retrofit - Whole Home Electrification

Cost Test	HP Technology	COU & Install Year							
		Richland		Inland		Tacoma		Clark	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.6	0.7	0.7	0.9	0.6	0.8	0.8	1.0
	ccASHP	0.5	0.6	0.6	0.8	0.6	0.7	0.7	1.0
	Dual-Fuel ASHP	0.5	0.6	0.6	0.8	0.5	0.7	0.7	0.9
RIM	Standard ASHP	1.2	1.2	1.0	0.9	1.4	1.4	1.4	1.4
	ccASHP	1.2	1.2	1.0	1.0	1.4	1.4	1.4	1.4
	Dual-Fuel ASHP	1.4	1.4	1.1	1.1	1.4	1.5	1.4	1.4

5.4.2 Single-Family Residential Retrofit - Delivered Fuel Water Heater Electrification

Cost Test	COU & Install Year			
	Tacoma		Clark	
	2025	*2035*	*2025*	*2035*
PCT	1.5	1.8	1.5	1.8
RIM	1.8	1.8	1.6	1.6

5.4.3 Multi-Family Residential Retrofit - HVAC Electrification

Cost Test	HP Technology	COU & Install Year			
		Richland		Inland	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.4	0.6	0.5	0.7
	ccASHP	0.4	0.5	0.5	0.7
	Dual-Fuel ASHP	0.3	0.4	0.3	0.4
RIM	Standard ASHP	1.2	1.2	0.9	0.9
	ccASHP	1.2	1.2	0.9	0.9

	Dual-Fuel ASHP	1.4	1.4	1.1	1.1

5.4.4 Small Healthcare Retrofit - Whole Building Electrification

Cost Test	HP Technology	COU & Install Year			
		Richland		Inland	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.9	1.2	1.0	1.3
	ccASHP	0.6	0.8	0.7	1.0
	Dual-Fuel ASHP	0.9	1.3	1.1	1.5
RIM	Standard ASHP	0.9	0.9	1.2	1.2
	ccASHP	0.8	0.7	0.9	0.9
	Dual-Fuel ASHP	1.1	1.1	1.5	1.5

5.4.5 Small Retail New Construction - Whole Building Electrification

Cost Test	HP Technology	COU & Install Year							
		Richland		Inland		Tacoma		Clark	
		2025	*2035*	*2025*	*2035*	*2025*	*2035*	*2025*	*2035*
PCT	Standard ASHP	0.7	0.8	0.7	0.9	0.9	1.1	1.3	1.6
	ccASHP	0.5	0.6	0.5	0.7	0.6	0.8	0.9	1.1
RIM	Standard ASHP	1.3	1.4	1.5	1.8	1.4	1.6	1.2	1.3
	ccASHP	1.4	1.5	1.6	1.9	1.4	1.6	1.3	1.3

5.4.6 Large Office New Construction - Whole Building Electrification

Cost Test	HP Technology	COU & Install Year			
		Tacoma		Clark	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	1.1	1.3	1.7	1.9
	ccASHP	1.0	1.2	1.5	1.8
RIM	Standard ASHP	1.2	1.4	1.0	1.1

	ccASHP	1.2	1.4	1.0	1.1

5.4.7 Large Healthcare New Construction - Whole Building Electrification

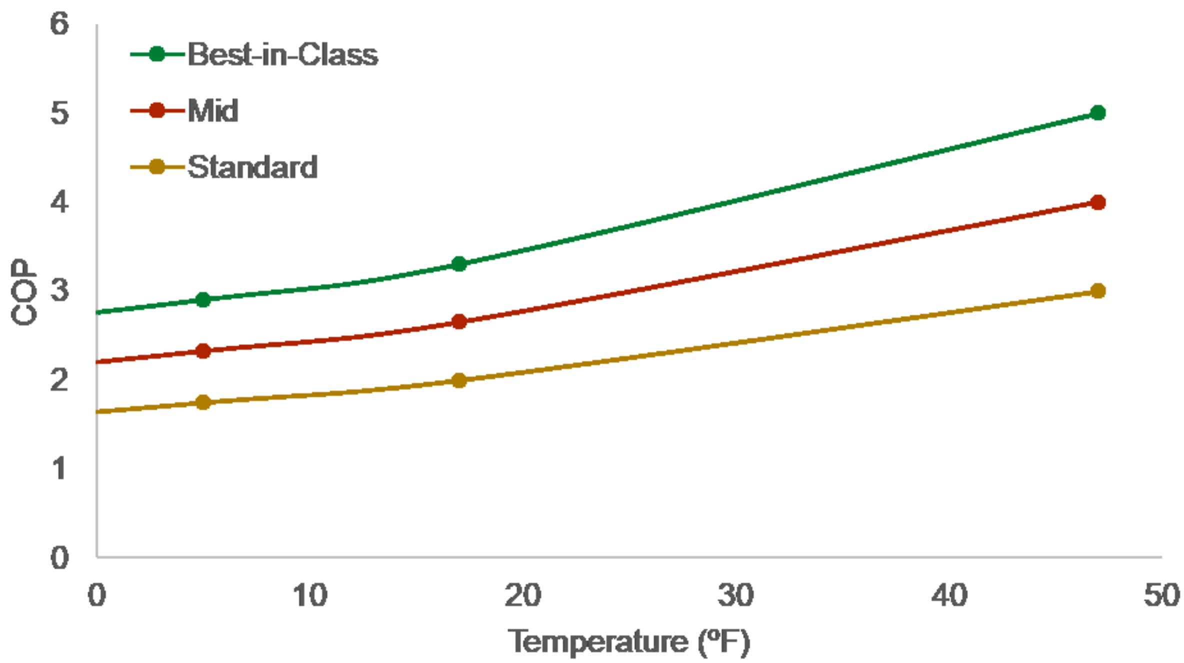
Cost Test	HP Technology	COU & Install Year			
		Tacoma		Clark	
		2025	*2035*	*2025*	*2035*
PCT	Standard ASHP	1.8	2.2	2.8	3.4
	ccASHP	1.6	2.0	2.3	3.0
RIM	Standard ASHP	1.1	1.1	1.0	1.0
	ccASHP	1.0	1.0	1.0	1.0

5.5 RESHAPE Modeling Assumptions

5.5.1 Coefficient of Performance (COP) Assumptions

E3 uses manufacturer reported data on the performance of ccASHPs provided by NEEP in its *Cold Climate Air Source Heat Pump Product List and Specifications*. Data from the NEEP database is used in RESHAPE to determine the standard, mid, and best-in-class curves in Figure 5-1, to reflect the minimum, medium and best heat pump products currently available on the market.

Figure 5-1. RESHAPE COP Curves



5.5.2 Heat pump sizing assumptions

Table 5-13 describes the heat pump sizing criteria used in the Task 3 Peak Load Impact analysis. Standard and mid performance all-electric heat pumps are sized according to standard practice to have a heat pump balance point temperature—the temperature below which the supplemental device would begin to serve heating demand—of 20ºF. Best-in-class all electric heat pumps were oversized such that the heat pump could serve the heating demand at the coldest historical temperature from 2004 to 2018. Hybrid heat pumps were sized to have a heat pump balance point temperature of approximately 30ºF. Below 30ºF, hybrid heat pumps rely entirely upon the backup fuel system to meet the heating demand.

While the State energy code specifies a minimum requirement of lock-out temperature at 40ºF for heat pumps, in practice, heat pumps are often oversized to ensure the customer's heating needs are satisfied. Also, under-sizing the heat pump would reduce the overall system efficiency and increase customer bills. Thus, E3 used the standard practice in the building industry to size all-electric heat pumps to a heat pump balance point temperature 20ºF and hybrid heat pumps to 30ºF.

Table 5-13. Heat pump sizing assumptions

Heat Pump Type	Utility	Standard Practice (% of Historical Demand, Temperature)	Improved System Configuration (% of Historical Demand, Temperature)
	Clark	99% (22ºF)	100% (7ºF)

Residential All Electric ASHP	Inland	95% (20ºF)	100% (-14ºF)
	Richland	98% (19ºF)	100% (-1ºF)
	Tacoma	99% (19ºF)	100% (0ºF)
Commercial All Electric ASHP	Clark	99% (22ºF)	100% (7ºF)
	Inland	95% (20ºF)	100% (-14ºF)
	Richland	98% (19ºF)	100% (-1ºF)
	Tacoma	98% (21ºF)	100% (0ºF)
Residential Hybrid HP	Clark	93% (30ºF)	
	Inland	79% (30ºF)	
	Richland	88% (30ºF)	
	Tacoma	89% (30ºF)	
Commercial Hybrid HP	Clark	93% (30ºF)	
	Inland	79% (30ºF)	
	Richland	88% (30ºF)	
	Tacoma	85% (30ºF)	

5.5.3 Shell improvement assumptions – Tight and Moderate Shell Scenarios

EnergyPlus simulations from Task 2 were used to assess the potential service demand reduction from shell retrofits. The Tight Shell scenario reflects a new construction built to WA code. The Moderate shell scenario reflects a low-cost shell improvement for a retrofit application.

Table 5-14. Tight shell scenario building envelope assumptions

Sector	% Reduction in Annual Heating Demand	% Reduction in Annual Cooling Demand	Wall Insulation	Roof Insulation	Infiltration	Glazing U-Value	Glazing SHGC
Residential	48%	11%	R-18	R-38	0.048 cfm/sf fac	U-0.30	SHGC-0.30
Commercial	38%	0%	R-18	R-38	0.048 cfm/sf fac	U-0.50	SHGC-0.30

Table 5-15. Moderate shell scenario building envelope assumptions

Sector	% Reduction in Annual Heating Demand	% Reduction in Annual Cooling Demand	Wall Insulation	Roof Insulation	Infiltration	Glazing U-Value	Glazing SHGC

Residential	5%	3%	R-11	R-30	0.11 cfm/sf fac	U-1.20	SHGC-0.40
Commercial	20%	0%	R-11	R-30	0.11 cfm/sf fac	U-1.20	SHGC-0.40

5.6 Additional Scenarios Modeled

In addition to the core sensitivities modeled, E3 explored two additional scenarios: Moderate Shell and Peak Mitigation.

Given the ambition of the **Tight Shell** scenario in both its scope and technical feasibility, E3 modeled an additional **Moderate Shell** scenario which illustrates the system impacts of a less ambitious retrofit that would be cost effective from the customer perspective. The envelope improvement modeled in this scenario would double roof insulation and reduce infiltration by half. For Clark PUD, the Moderate Shell scenario would have minimal impact on annual energy sales and would reduce peak load by less than 9%.

While the core scenarios represent the maximum potential of individual load management strategies on mitigating system impacts, in practice, COUs would likely explore a combination of strategies and would be unlikely to reach every customer with the full individual measure explored in the scenario. E3 considered a **Peak Mitigation** scenario where a combination of strategies in the core scenario were combined. The Peak Mitigation scenario considers best-in-class heat pump adoption in new construction and residential retrofits, complete electric residential electric resistance phaseout, and adoption of dual-fuel heat pumps in the commercial retrofits. With this combination of load management strategies, peak and annual energy sales is expected to grow between -3 to 1% over current system load by 2050 ranging across the COUs. While this scenario is highly ambitious, it illustrates that there is significant potential to manage electrification to mitigate system impacts.

Table 5-16 Moderate Shell and Peak Mitigation Scenario Design

	Base Case	Moderate Shell	Peak Mitigation
Heat Pump Performance	ASHPS are 100% mid performance		Dual-Fuel HPs are mid performance and ASHPs are 100% high performance
Heat Pump Sizing	ASHPs sized at to a heat pump balance point temperature of 20º		Dual-Fuel HPs are sized to a heat pump balance point of 30ºF and all-electric heat pumps are oversized
Backup Fuel	Residential and commercial customers rely on electric resistance in coldest hours		Residential relies on electric resistance and commercial

	Base Case	Moderate Shell	Peak Mitigation
			customers rely on fuel in coldest hours
Building Shell Improvements	New construction built with a tight shell; Existing building stock does not retrofit shells	New construction built with a tight shell; Existing building stock does have a moderate improvement to the building envelope.	New construction built with a tight shell; Existing building stock does not retrofit shells
Today's fuel customers	Adopt All-Electric ASHP		Commercial fuel customers adopt dual-fuel HPs. Residential fuel customers adopt all-electric HPs
Today's Electric Resistance Customers	~50% of current residential electric resistance customers adopt heat pumps consistent with the SES		All current resistance customers adopt heat pumps.

Table 5-17 1-in-2 Peak Load Growth by 2050 for Additional Scenarios

	Base	Moderate Shell	Peak Mitigation
Clark	36%	33%	1%
Inland	72%	72%	-2%
Richland	41%	39%	-3%
Tacoma	33%	21%	2%

Table 5-18 1-in-10 Peak Load Growth by 2050 for Additional Scenarios

	Base	Moderate Shell	Peak Mitigation
Clark	51%	49%	1%
Inland	76%	71%	-7%

Richland	51%	49%	-11%
Tacoma	44%	40%	2%

Table 5-19 1-in-2 Annual energy sales Growth by 2050 for Additional Scenarios

	Base	Moderate Shell	Peak Mitigation
Clark	7%	7%	1%
Inland	13%	13%	-1%
Richland	10%	10%	-1%
Tacoma	7%	6%	1%

5.7 Additional Peak Load Impact Results

5.7.1 Tacoma Power System Impacts

Figure 5-2 and Figure 5-3 show the system impact results for the core scenarios for Tacoma Power. Under the Base Case scenario, the 1-in-2 peak load is expected to increase by 33% by 2050 and the 1-in-10 peak load is expected to increase by 44%. The ER Phaseout scenario has the lowest annual energy sales impacts due to the significant efficiency gained from transitioning resistance heating to heat pumps. Peak impacts are expected to be lowest in the Hybrid scenario.

Figure 5-2. Tacoma Power Annual energy sales Growth in 2050

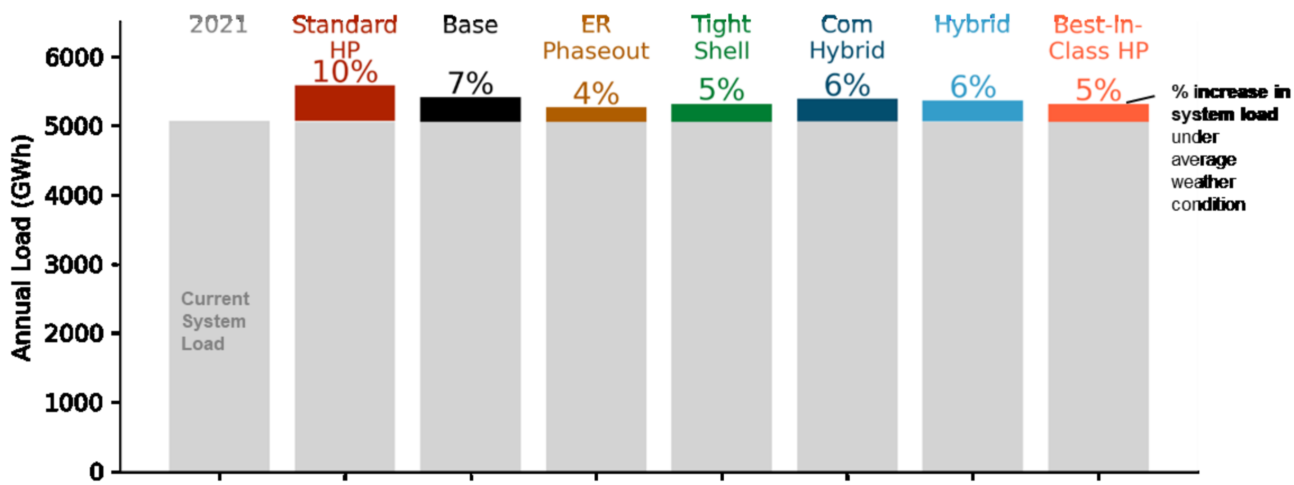
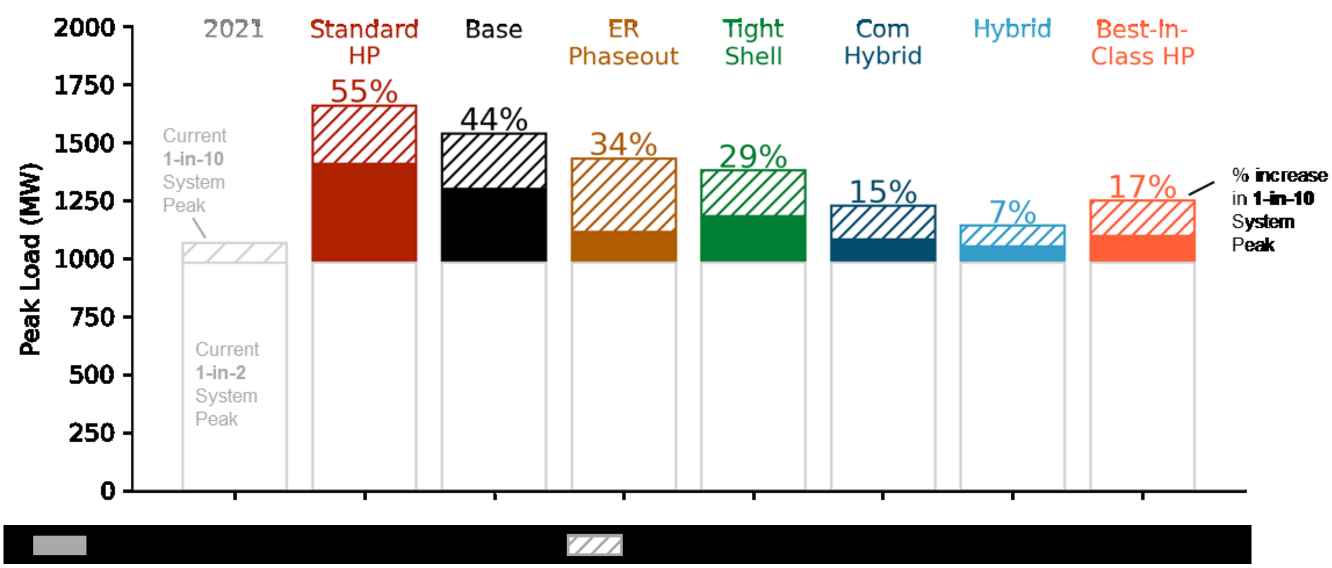


Figure 5-3. Tacoma Power 1-in-2 System Peak Load Growth in 2050



5.7.2 Inland Power and Light System Impacts

Figure 5-4 and Figure 5-5 summarize the system impact results for Inland Power and Light. Inland's 1-in-2 peak load is expected to grow by 72% by 2050 and the 1-in-10 peak load is expected to grow by 76%. Electrification is expected to significantly increase due to the utility's cold climate and existing winter peak. However, the deployment of dual-fuel heat pumps and high performance all-electric heat pumps have the potential to mitigate system impacts.

Figure 5-4. IPL System Annual energy sales Growth in 2050

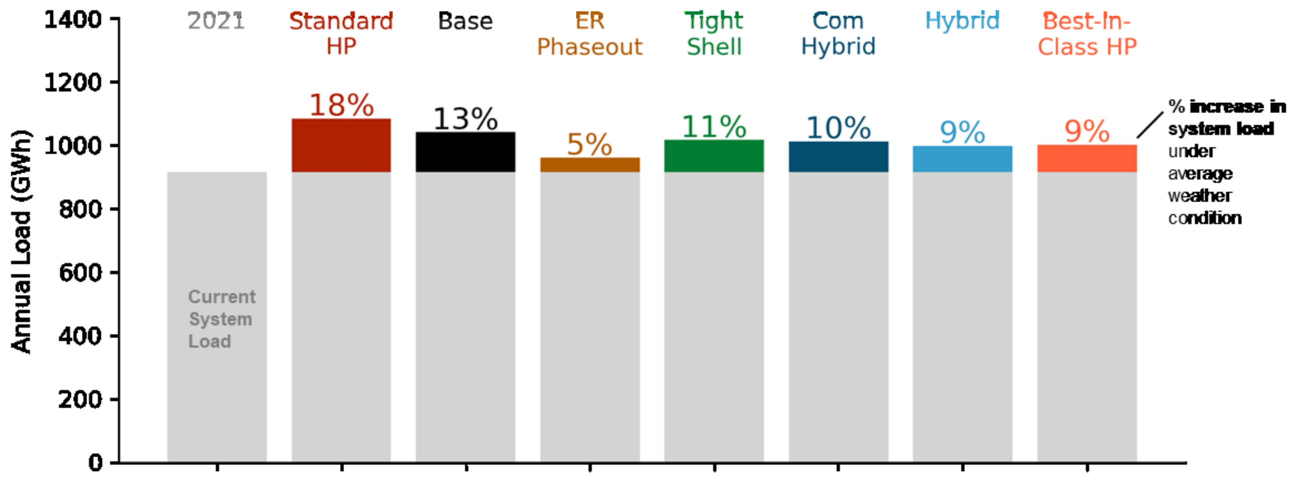
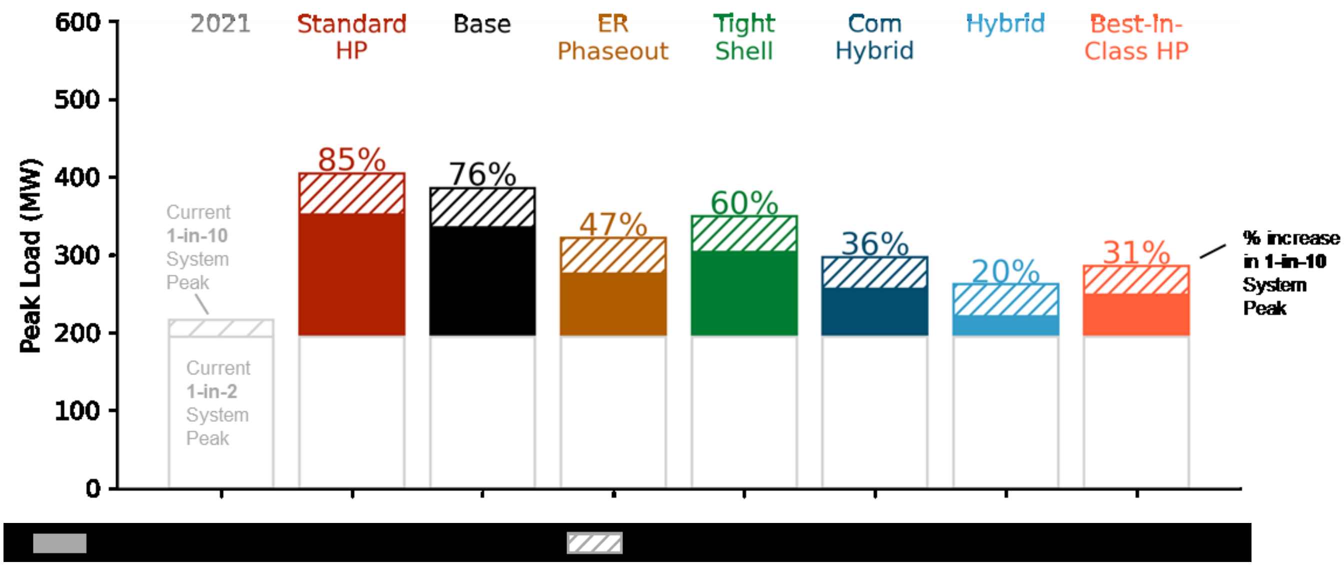


Figure 5-5. IPL 1-in-2 System Peak Load Growth in 2050



5.7.3 Richland Energy Services System Impacts

Figure 5-6 and Figure 5-7 summarize the system impact results for Richland Energy Services. In the Base Case scenario, the 1-in-2 peak load is expected to increase 41% by 2050 and the 1-in-10 peak load is expected to increase by 51%.

Figure 5-6. RES System Annual energy sales Growth in 2050

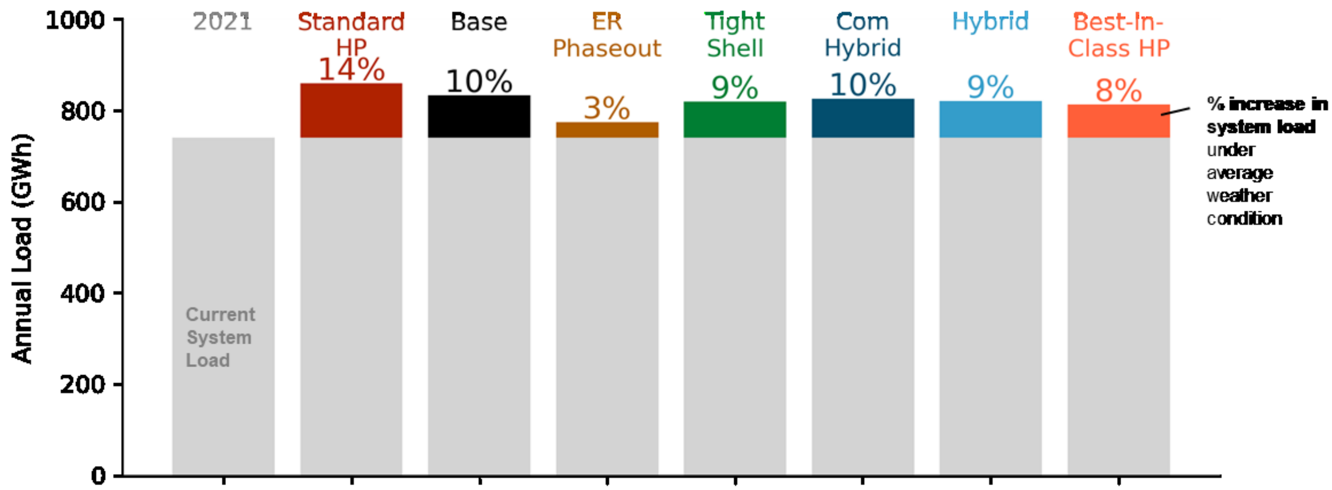
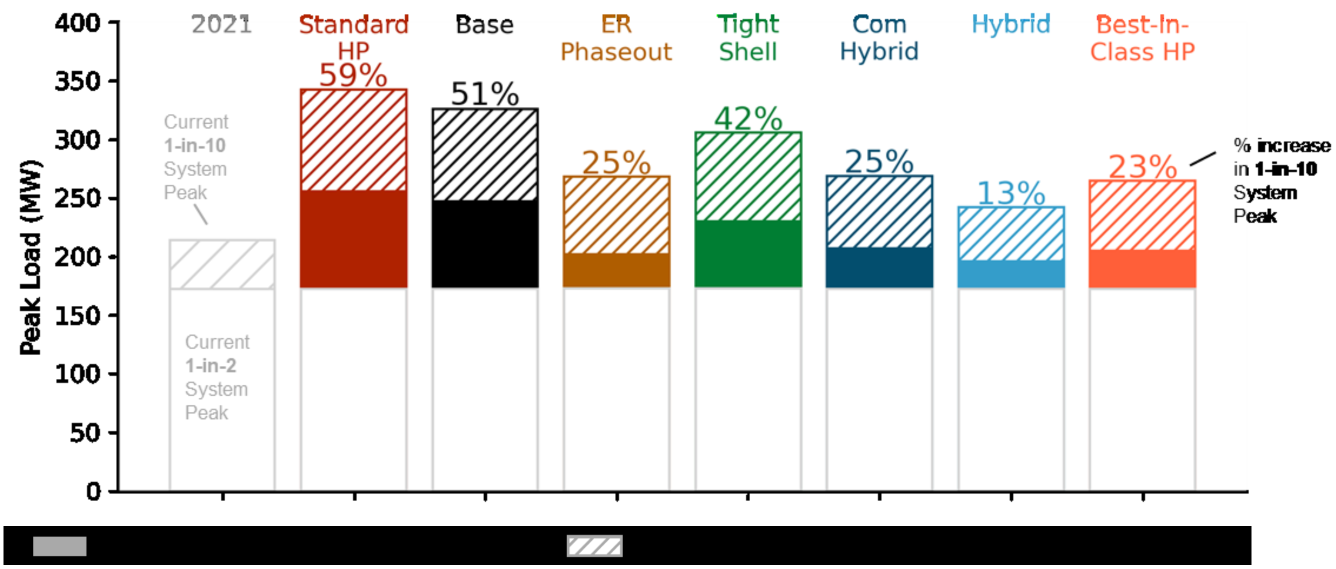


Figure 5-7. RES 1-in2 System Peak Load Growth in 2050

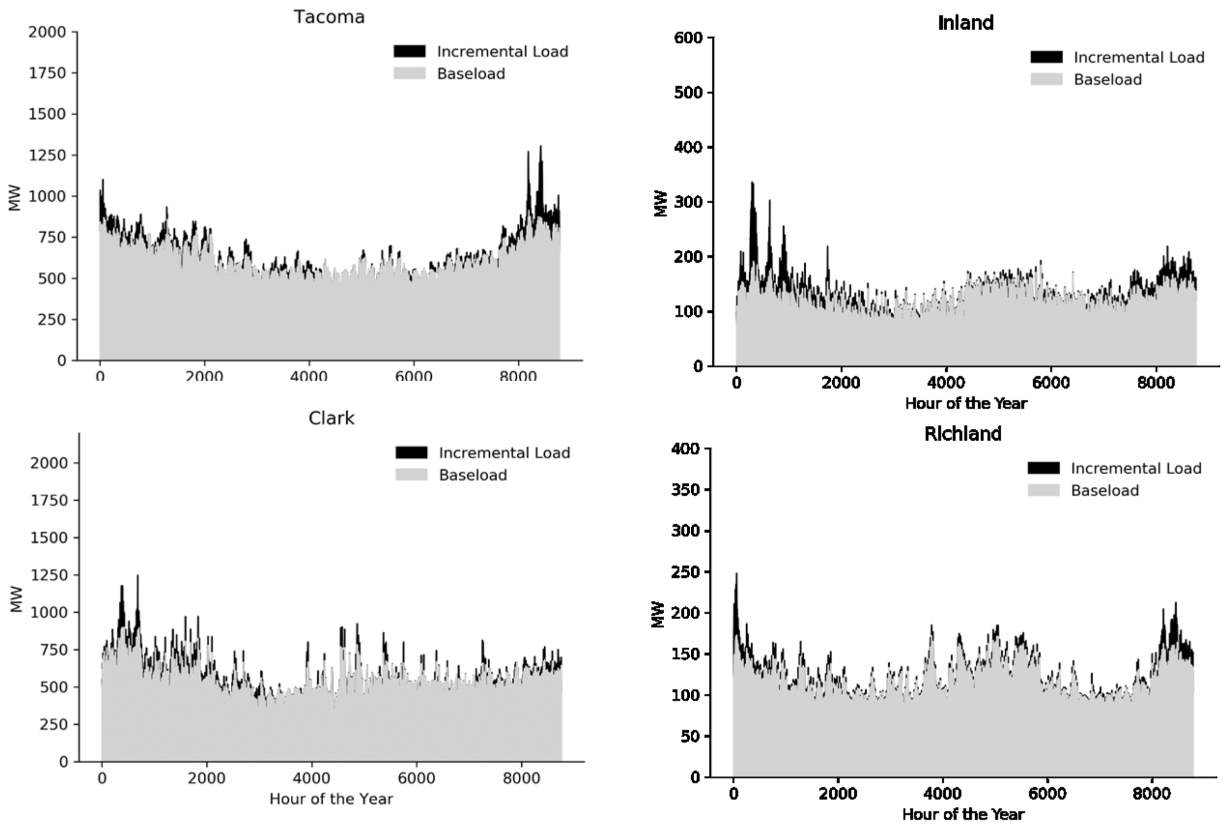


5.7.4 Utility Results Comparison

Base

Figure 5-8 shows the existing system baseload and the incremental load from electrification in 2050 under the Base Case scenario in a 1-in-2 weather year. Most of the incremental load from electrification is added in winter hours in which load is already high for all COUs. Thus, electrification adds load to existing winter peaks for the COUs leading to significant peak load growth.

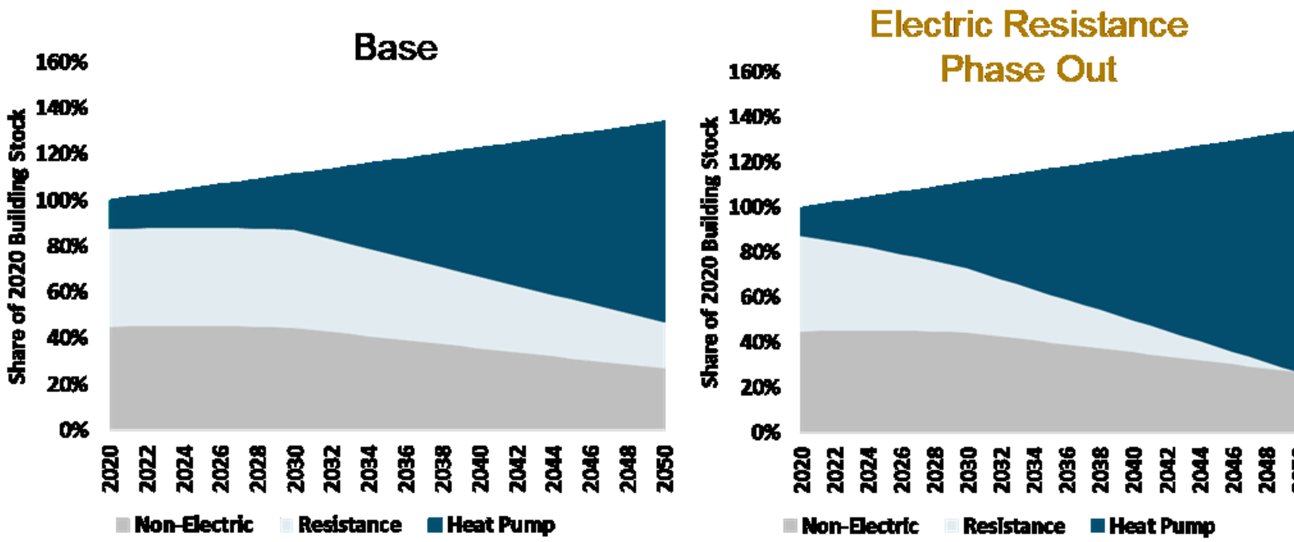
Figure 5-8. Base case scenario system load in 2050 for a 1-in-2 Weather Year (Tacoma: 2016, Inland: 1997, Clark: 2002, Richland: 1984)



Electric Resistance Phaseout

Figure 5-9 shows the modeled residential building stock roll over in the Base Case scenario and the Electric Resistance Phaseout scenario. In the Electric Resistance Phaseout scenario, all electric resistance heating used in the residential sector is eliminated by 2050. All scenarios assume the same change in commercial building stock and that the current portion of electric resistance in the commercial building stock remains constant.

Figure 5-9. Residential building stock comparison in Base and Electric Resistance Phaseout Scenarios



With complete phase out of electric resistance heating in the residential sector, utilities can reduce the system impact of electrification. The phaseout of electric resistance heating has a bigger impact on mitigating annual energy sales growth than peak load growth due to the reduced efficiency of heat pumps during the coldest hours. While Richland has the lowest share of current resistance customers, the analysis shows that fuel and electric resistance households have similar service demand in Richland whereas in other jurisdictions the service demand of fuel customers is generally greater than current electric resistance customers. This leads to greater reduction in load and peak in the ER Phaseout scenario for Richland where the retirement of resistance heating systems offsets load growth from fuel switching more.

Figure 5-10. Annual energy sales Growth (1-in-2) for Electric Resistance Phaseout Scenario by 2050

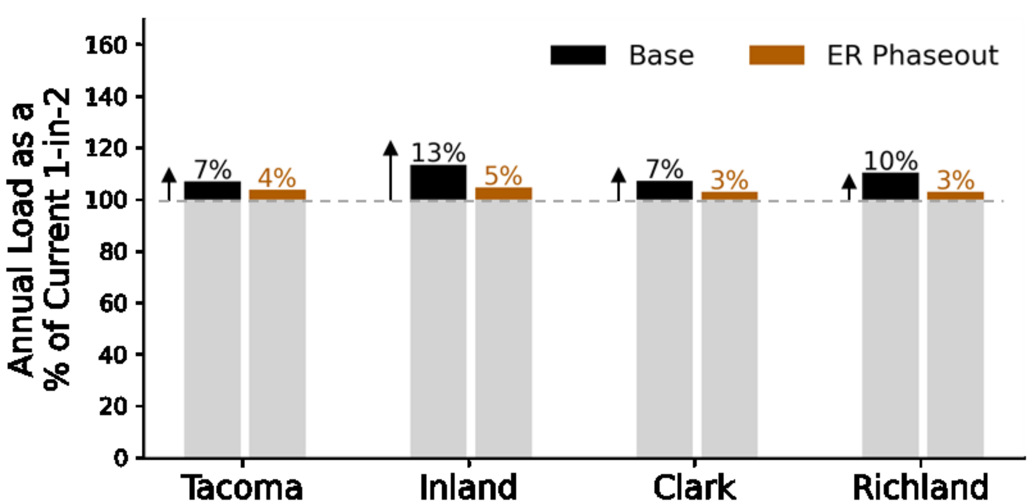
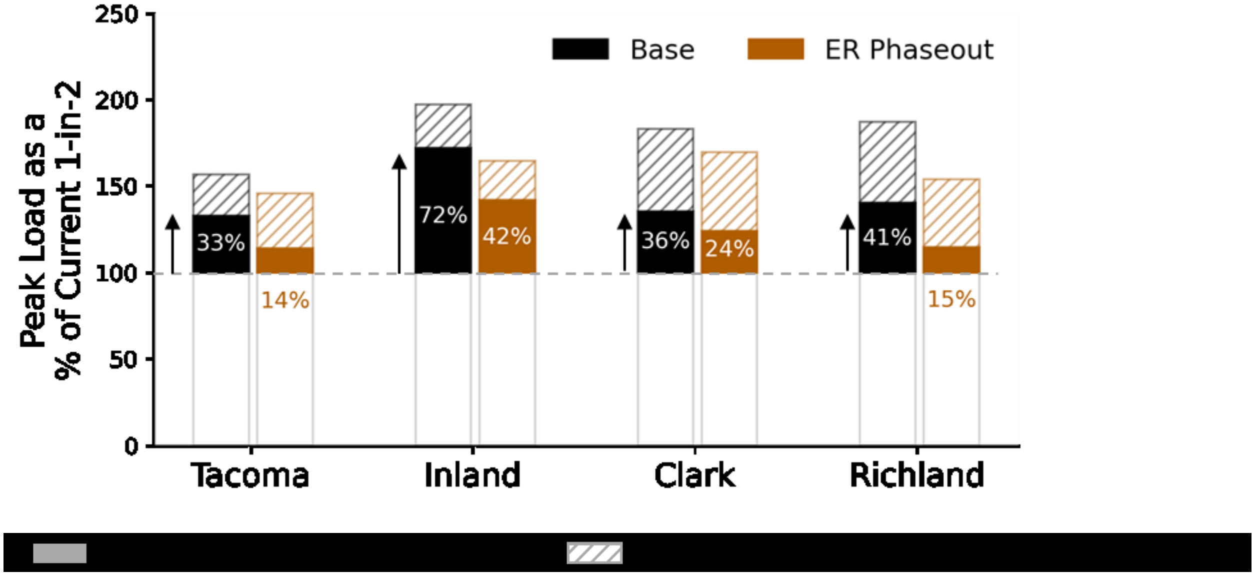


Figure 5-11. Peak Load Growth for Electric Resistance Phaseout Scenario by 2050



Tight and Moderate Shell

Figure 5-12 and Figure 5-13 compare the system impacts of the Tight Shell and Moderate Shell scenarios across the COUs. The Moderate Shell scenario has the smallest impact on reducing peak load growth of all the scenarios modeled.

Figure 5-12. Annual energy sales Growth (1-in-2) for Moderate and Tight Shell Scenarios by 2050

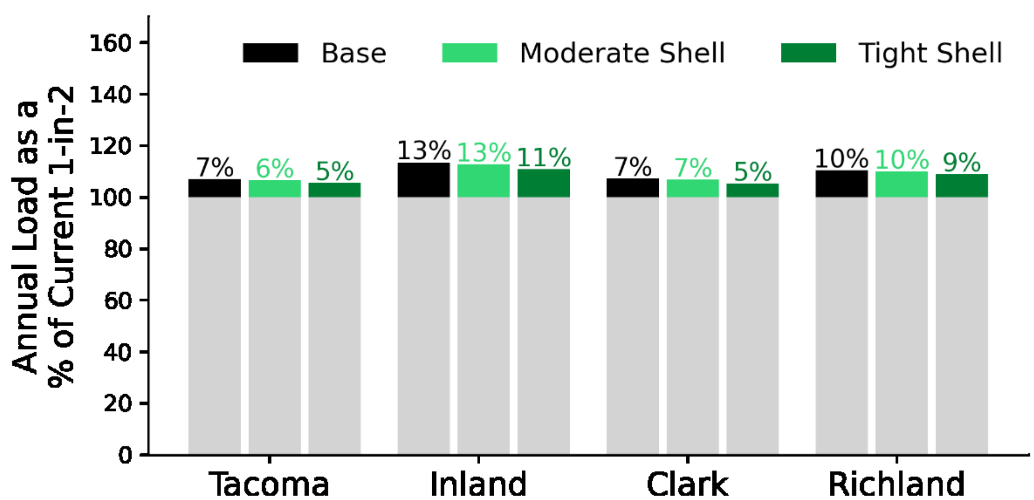
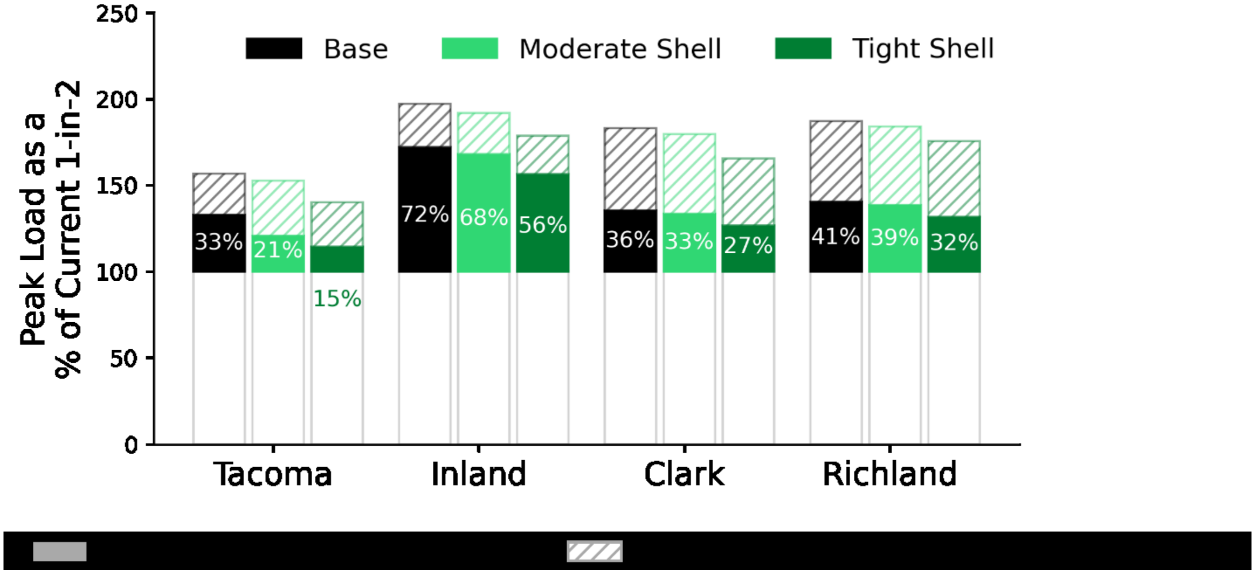


Figure 5-13. Peak Load Growth for Moderate and Tight Shell Scenarios by 2050



Standard HP

Figure 5-14 and Figure 5-15 compare the Base Case and Standard HP scenarios across COUs showing that system impacts are significantly greater when base performance heat pumps are relied upon for electrification.

Figure 5-14. Annual energy sales Growth (1-in-2) Standard HP Scenario by 2050

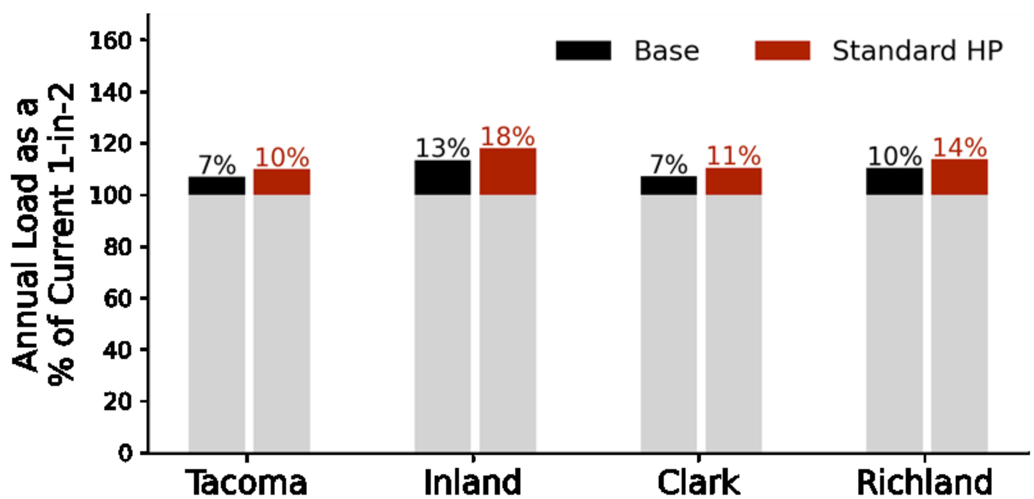
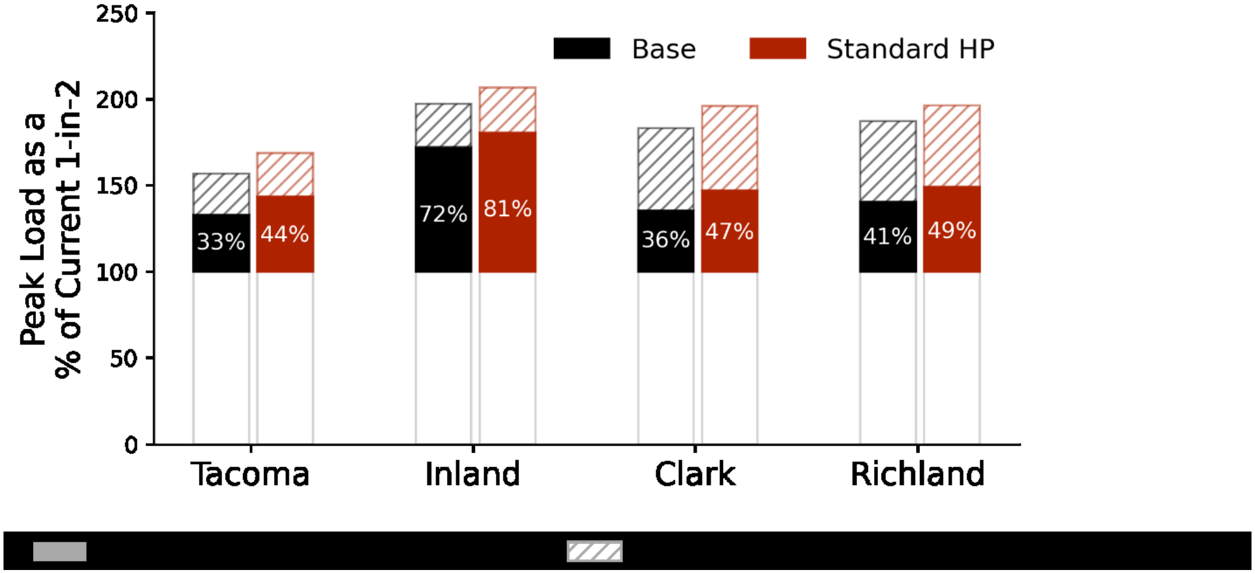


Figure 5-15. Peak Load Growth for Standard HP Scenario by 2050



Best-in-Class HP

Figure 5-16 and Figure 5-17 compares the Base Case and Best-in-Class HP scenarios across COUs.

Figure 5-16. Annual energy sales Growth (1-in-2) Best-in-Class Scenario by 2050

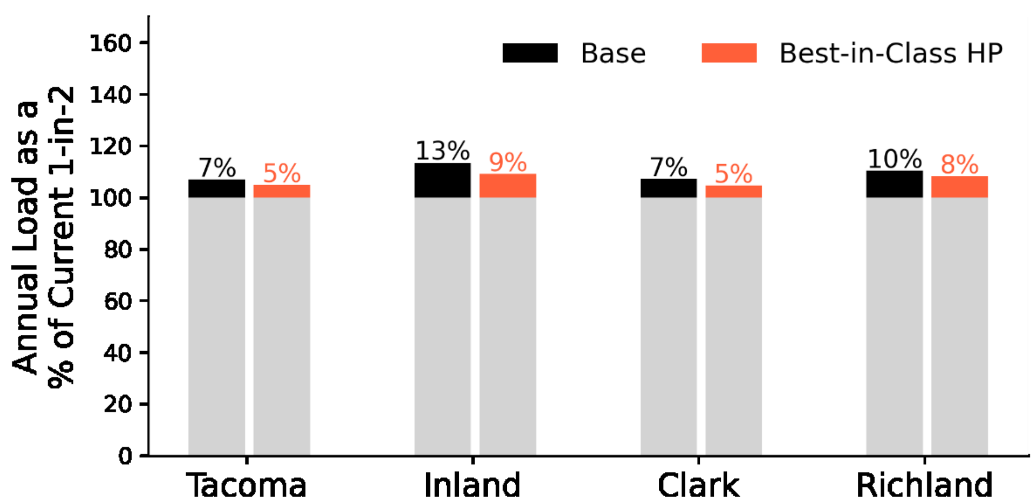
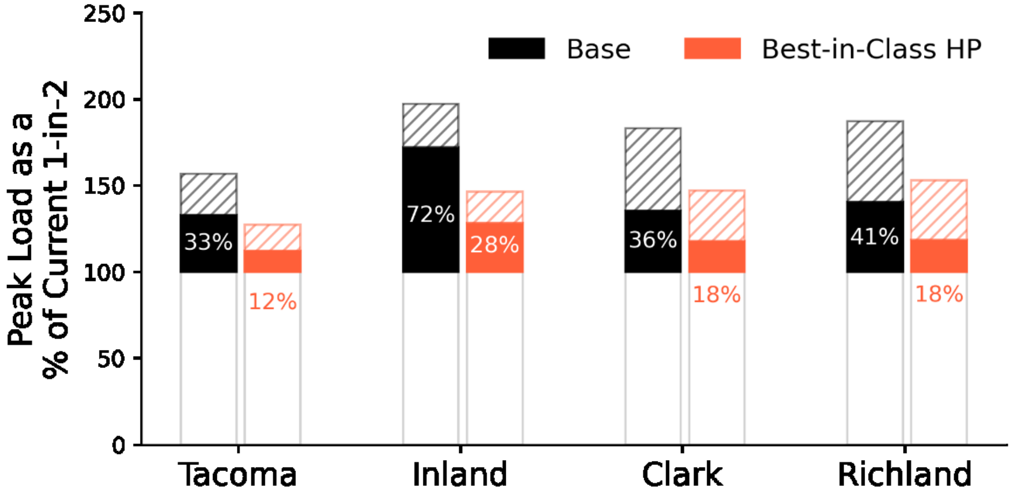


Figure 5-17. Peak Load Growth for Best-in-Class HP by 2050



[redacted]

Hybrid and Commercial Hybrid

Figure 5-18 and Figure 5-19 compares the Base Case, Commercial Hybrid, and Hybrid scenarios across COUs.

Figure 5-18. Annual energy sales Growth (1-in-2) for Hybrid and Commercial Hybrid Scenarios by 2050

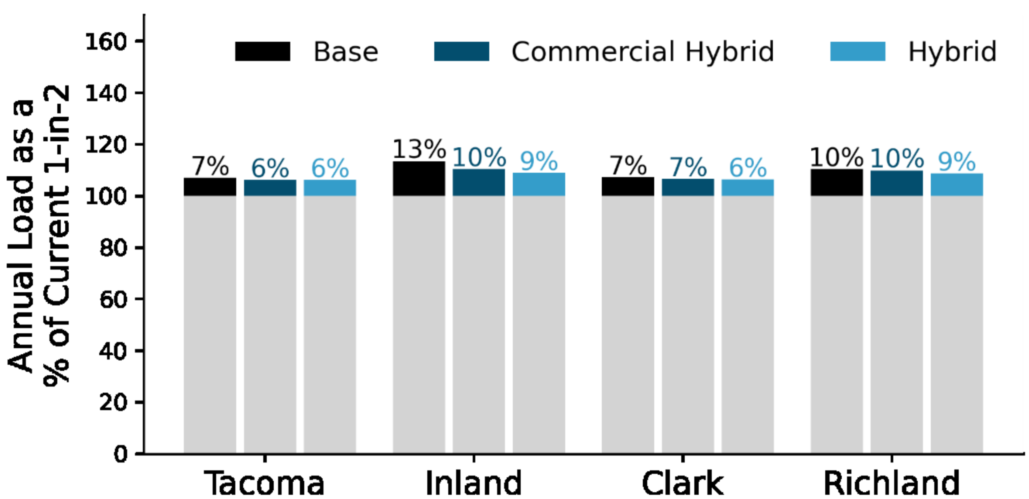


Figure 5-19. Peak Load Growth for Hybrid and Commercial Hybrid Scenarios by 2050

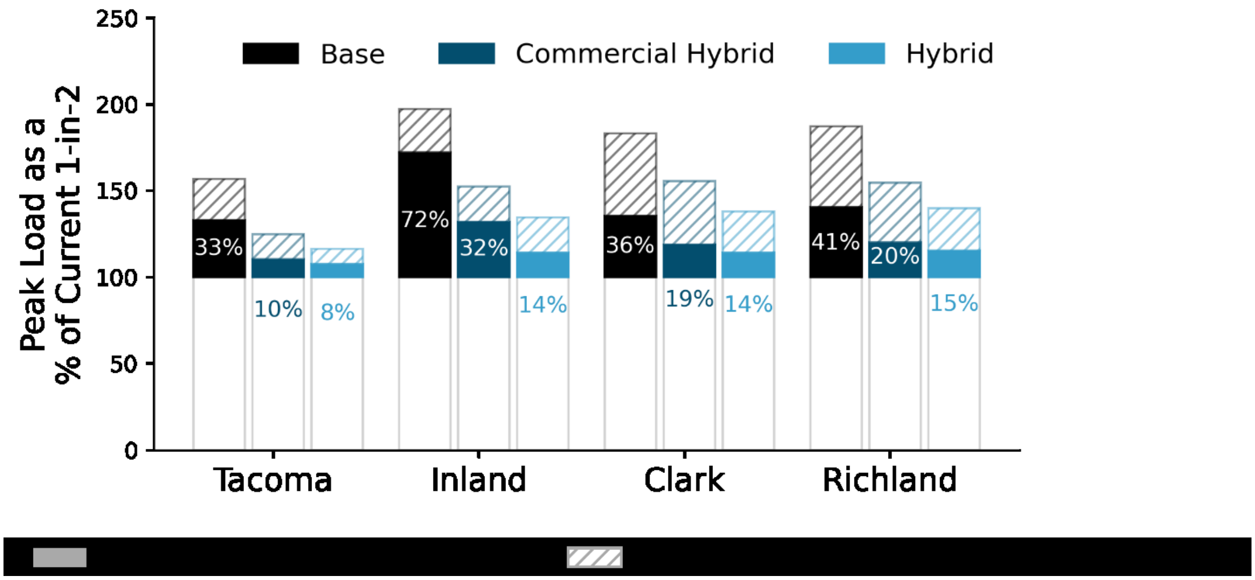


Figure 5-20 shows the expected daily peak load in the Base Case, Commercial Hybrid, and Hybrid scenarios in 2050 under a 1-in-2 weather year. On peak days, the total system load in the hybrid scenarios is much lower than the Base Case scenario due to the use of backup fuels to serve heating demand. On milder days, where the compressor of a dual-fuel heat pump can serve the entire heating load, the system load is consistent across hybrid and Base Case scenarios.

Figure 5-20. Hybrid and Commercial Hybrid scenario system load in 2050 for a 1-in-2 Weather Year (Tacoma: 2016, Inland: 1997, Clark: 2002, Richland: 2016)