Pacific Northwest Low Carbon Scenario Analysis

Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector

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Energy+Environmental Economics

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Conventions

+ All costs reported in this study are reported in real 2016 dollars.
+ All references to quantities of greenhouse gas emissions are reported using units of metric tons (or tonnes).

Acronyms

AEO	Annual Energy Outlook
BPA	Bonneville Power Administration
CCGT	Combined cycle gas turbine
CGS	Columbia Generating Station
CHP	Combined heat and power
CT	Combustion turbine
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
ELCC	Effective load carrying capability
EV	Electric vehicle
GHG	Greenhouse gas
HLH	Heavy load hours
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated resource plan
LLH	Light load hours
LOLP	Loss of load probability
NREL	National Renewable Energy Laboratory
NWPCC	Northwest Power and Conservation Council
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
PV	Photovoltaic
REC	Renewable energy credit
RPS	Renewables Portfolio Standard
TEPPC	Transmission Expansion Policy and Planning Committee
WECC	Western Electricity Coordinating Council

ES Executive Summary

Study Overview

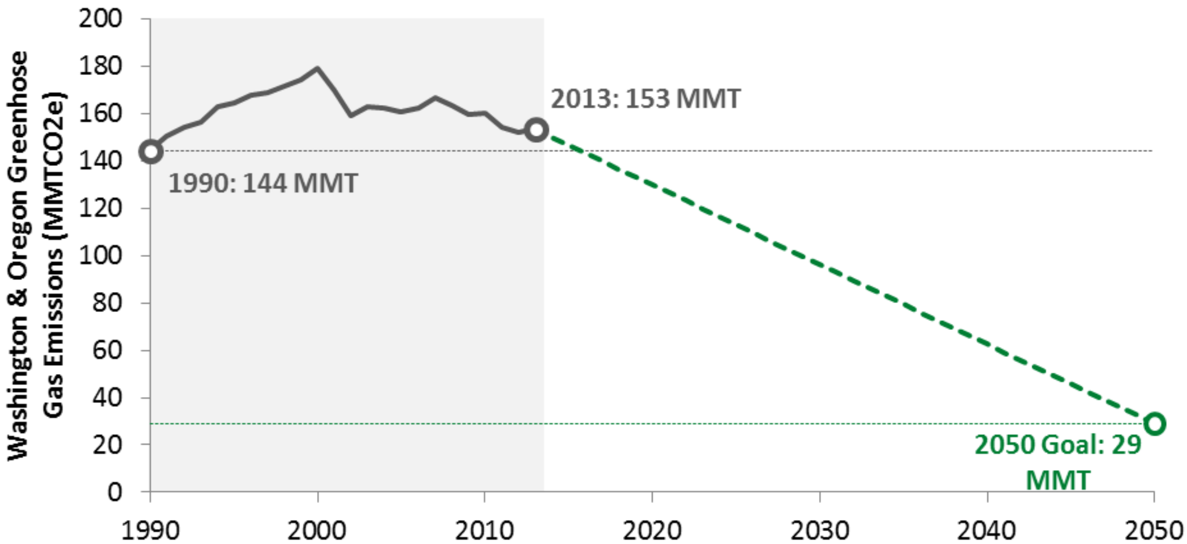
In the past year, both Washington and Oregon have considered expanding existing greenhouse gas reductions targets to establish goals for long-term deep decarbonization:

- In Washington, the Department of Ecology has proposed a revision to existing targets that would require a **40% reduction below 1990 levels by 2035** and an **80% reduction by 2050**.
- Oregon state legislators contemplated increasing the state's existing greenhouse gas reduction goal—75% reduction below 1990 levels by 2050, established by House Bill 3543 in 2007—to a **91% reduction goal**.

As shown in Figure i, achieving an 80% reduction goal across the two combined states would require economy-wide emissions reductions of 124 million metric tons between 2013 and 2050.

These deep decarbonization goals are ambitious. Their adoption and implementation should be accompanied by careful consideration of how they could best be achieved while moderating the costs. This study seeks to contribute to the discussion on how to meet the Pacific Northwest's deep decarbonization goals by exploring how the region's electric sector could most effectively and efficiently contribute to the achievement of emissions reduction goals.

Figure i. Trajectory to meet 80% economy-wide greenhouse gas emissions reduction goal, Washington & Oregon



The electricity sector currently accounts for roughly one quarter of the total economy-wide emissions—36 million metric tons based on the states' 2013 emissions inventories. The emissions attributed to electric ratepayers within the region comprise emissions associated with utility-owned coal and gas generation—both resources physically located in the region as well as those outside the region but owned by utilities that serve Washington and Oregon customers—as well as emissions attributed to market purchases. While the region's sizeable fleet of hydro, nuclear, and renewable resources, results in an average carbon intensity that is relatively low in comparison to other regions, further emissions reductions within the electric sector will be needed to meet the states' proposed goals.

This study seeks to provide decision-makers with useful information on the potential policies through which the electric sector in the Pacific Northwest can most effectively contribute to meeting economy-wide emissions reductions goals. The specific questions it addresses are:

+ What combination of generation resources will provide the most cost-effective sources of greenhouse gas reductions within the electric sector while meeting reliability needs?
+ What types of policies will enable the achievement of emissions reductions goals in the electric sector at least cost?
+ How will different policies impact the long-term viability of existing low-carbon resources in the Northwest, including hydro, nuclear, and energy efficiency?

This study relies on scenario analysis using E3's RESOLVE model to evaluate the implications of a variety of different policies in both their effectiveness at reducing carbon emissions within the electric sector as well as their cost impacts for electric ratepayers. RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. RESOLVE is designed with the capability to model explicitly a variety of different types of prospective policies, including increased Renewables Portfolio Standards (RPS), carbon cap trade programs, carbon taxes, and prohibitions on new investments in fossil fueled generation. Through scenario analysis of these alternative policies, this study highlights their relative effectiveness with respect to meeting long-term decarbonization goals.

Methodology & Assumptions

This study focuses on a suite of "Core Policy Scenarios," reflecting a range of policies that could be used to effect greenhouse gas reductions in the electric sector in the Washington and Oregon[1]—referred to in this study as the "Core Northwest" region:

- A **Reference Case** that reflects current state policies and industry trends, intended to serve as a point of comparison for alternative prospective policies;
- A range of **High RPS Cases**, which test the impact of broadly increasing the RPS goals established by existing statutes in the states of Washington and Oregon;
- A range of **Carbon Cap Cases**, which impose limits on the total greenhouse gas emissions attributed to ratepayers in Washington and Oregon;
- Two **Carbon Tax Cases**, which simulate the impact on the electric sector of carbon tax policies that have been proposed by the Governor and the Washington legislature; and
- A **No New Gas Case**, which prohibits the construction of new gas generation, forcing all future energy and capacity needs to be met by GHG-free resources.

The full set of Core Policy Scenarios included in the study is shown in Table i.

[1] The study's footprint also includes small portions of Idaho and Montana that represent the geographic areas served by Avista Corporation and the Bonneville Power Administration.

Table i. Full list of Core Policy scenarios

Category	Scenario Name	Description
Reference Case	Reference Case	Current state policy & industry trends
High RPS Cases	30% RPS	Increasingly stringent RPS targets on the region as a whole (note: current state policies would require achievement of a region-wide 20% RPS by 2040)
	40% RPS	
	50% RPS	
Carbon Cap Cases	40% GHG Reduction	Increasingly stringent carbon caps on the study footprint
	60% GHG Reduction	
	80% GHG Reduction	
Carbon Tax Cases	Governor's Tax	Two independent proposals for carbon taxes under discussion in Washington State
	Legislature's Tax	
No New Gas Case	No New Gas	Prohibition on new gas generation

All scenarios rely upon a common set of assumptions, largely derived from data gathered from existing regional planning processes, to characterize the forecast of future demand and a common set of generation resources intended to capture current industry trends. Key assumptions include:

+ Load growth is partially offset by acquisition of cost-effective energy efficiency identified by the Northwest Power and Conservation Council, which reduces regional load growth from 1.3% per year to 0.7% per year;
+ Columbia Generating Station, the region's 1,207 MW nuclear plant, and the region's existing hydro resources (31,500 MW) remain in service through 2050;
+ Existing coal plants (including plants geographically located outside of the region but owned by utilities that serve loads within the region) remain in service through 2050 with the exception of announced retirements, which include Boardman, Centralia 1 & 2, and Colstrip 1 & 2; and
+ Existing gas plants within the region remain in service through 2050, with several exceptions where plants reaching the ends of their economic lifetimes have been flagged for retirement.

To meet the residual energy and capacity needs of the system in each policy scenario, RESOLVE selects new investments needed in ten-year increments between 2020 and 2050. The menu of resource options available for consideration is shown in Table ii; each resource is characterized by assumptions on the maximum potential, investment cost, and operational characteristics.

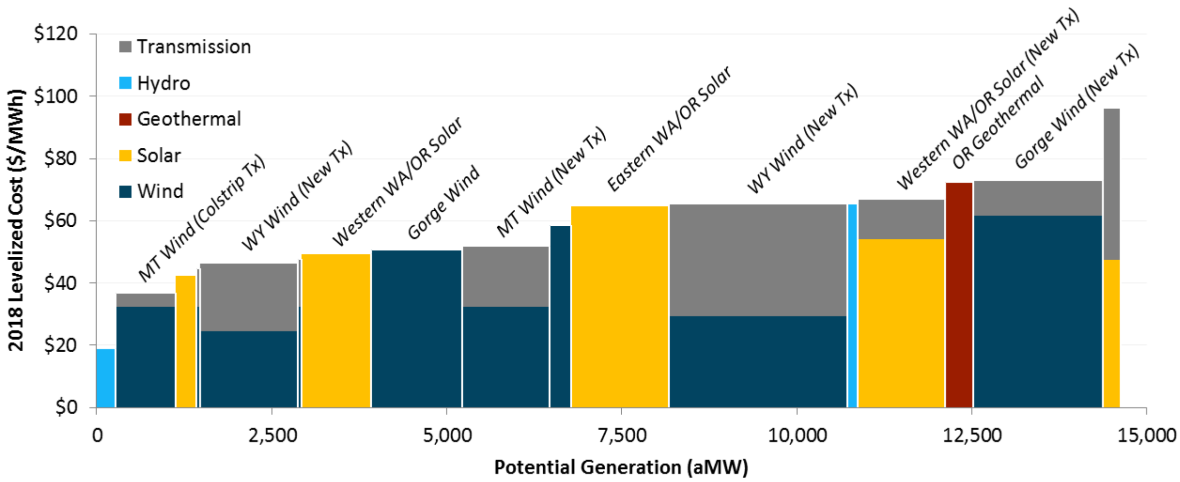
Inputs and assumptions used to characterize each resource type are derived from NWPCC's Seventh Power Plan where possible and supplemented with additional information where necessary.

Figure ii shows, as an example, the supply curve for new renewable resources considered in each scenario of the study.

Table ii. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines • Repowered CCGTs	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Geothermal • Hydro upgrades • Solar PV • Wind	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load
Energy Storage	• Batteries (>1 hr) • Pumped Storage (>12 hr)	• Stores excess energy for later dispatch • Contributes to meeting ramping needs
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Interruptible tariff (ag) • DLC: space & water heating (res)	• Contributes to planning reserve margin needs

Figure ii. Supply curve of potential new renewable resources



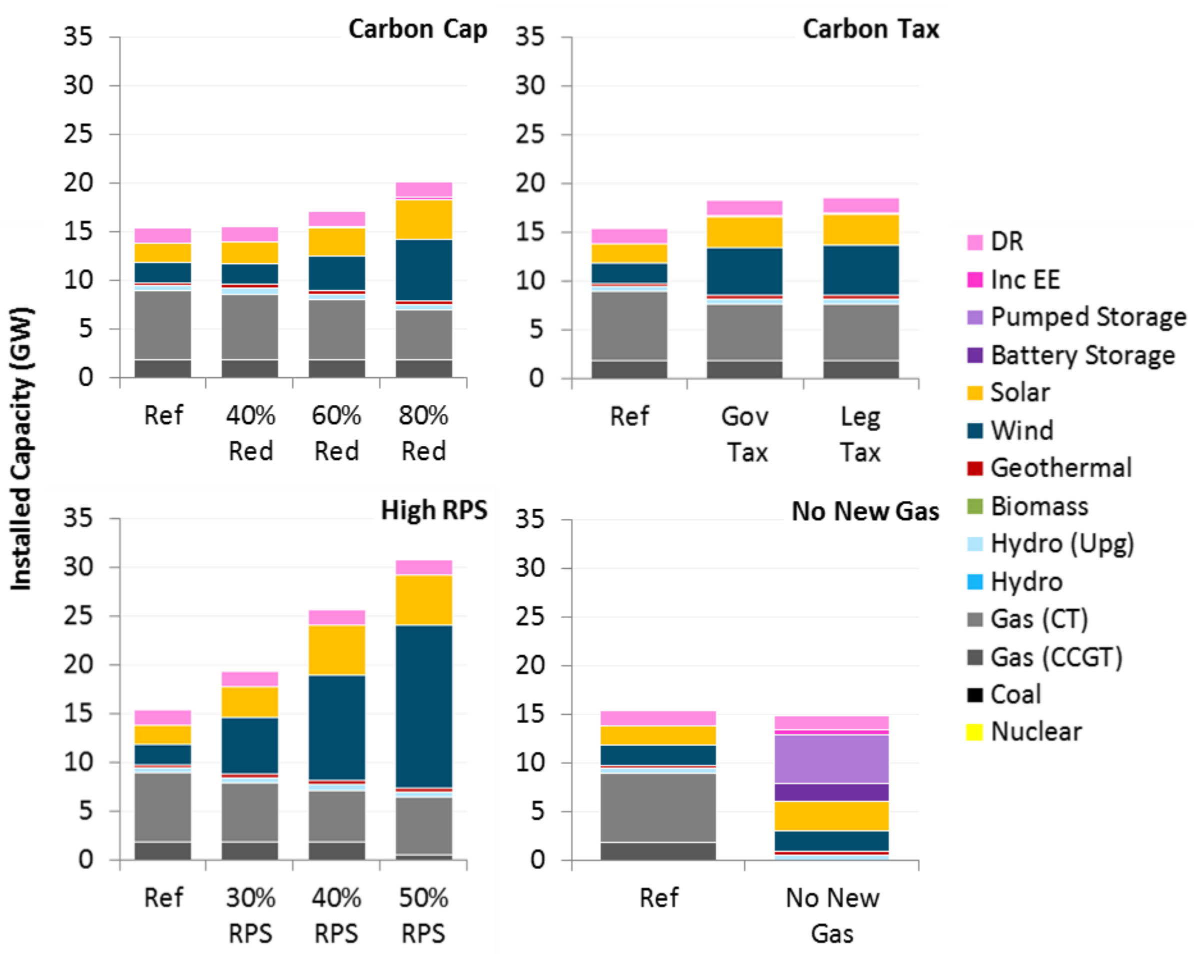
Portfolio Impacts

The types of new investments and operational decisions made in each scenario satisfy the energy and capacity needs of the portfolio while reflecting the impact of the corresponding policies modeled. The least-cost resource portfolios in 2050 in each scenario are shown in Figure iii (new investments relative to existing fleet selected by RESOLVE) and Figure iv (summary of total annual generation mix in the Core Northwest region).

+ In the **Reference Case**, two types of new investments are selected in the least-cost portfolio: (1) 5,000 MW of new renewable resources needed to meet increasing regional RPS policy goals by 2050 (including 2,100 MW of wind and 2,000 MW of solar), and (2) 9,000 MW of new capacity resources needed to maintain reliability as load grows while existing coal plants retire (1,600 MW of demand response and 7,200 MW of new gas combustion turbines).

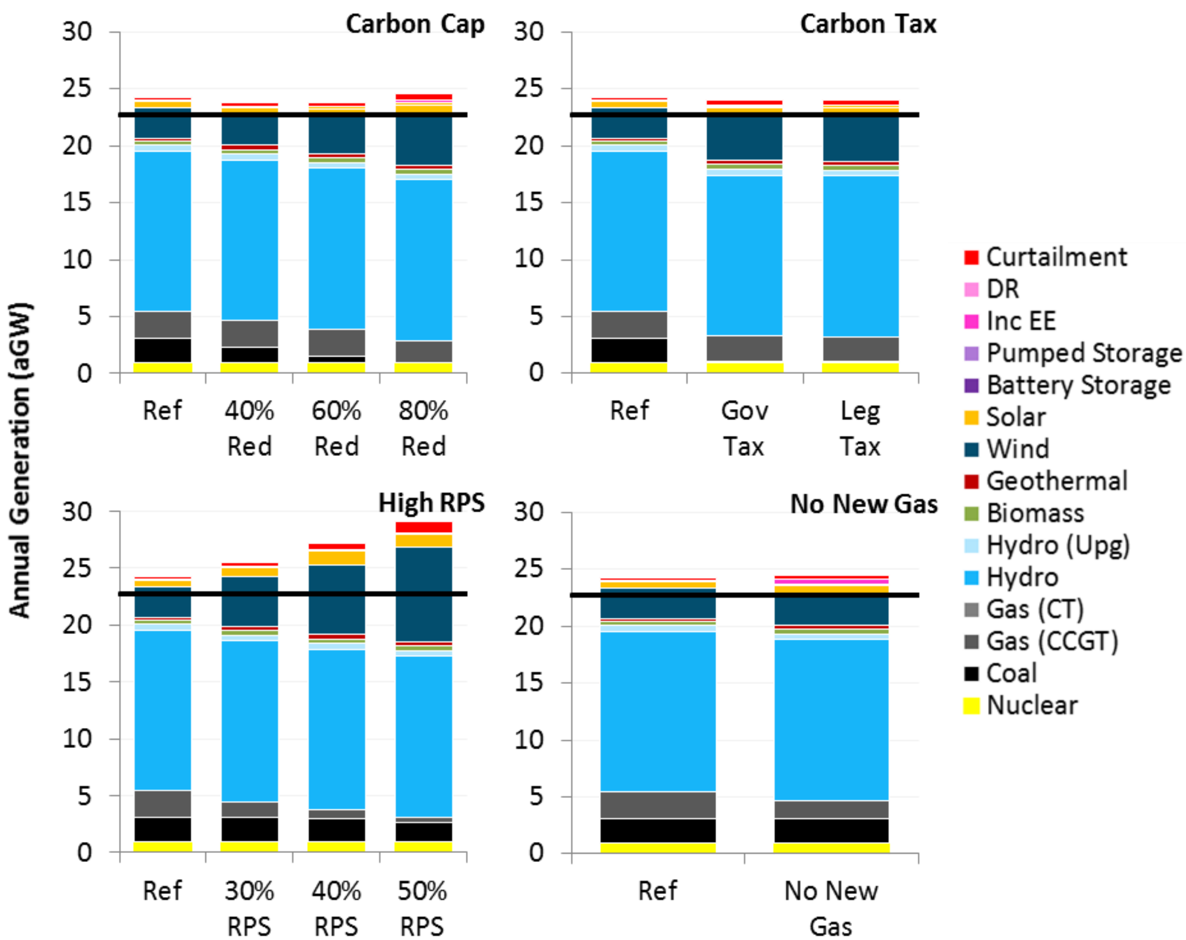
- The **Carbon Cap** scenarios use a combination of three types of measures to achieve required greenhouse gas reductions to reach the emissions reduction goal in the 80% Reduction scenario: (1) incremental investments in renewable generation, which increases from 5 GW in the Reference Case to 11 GW; (2) acquisition of incremental energy efficiency, wherein 250 aMW of incremental efficiency potential is acquired; and (3) coal displacement, as the carbon price signal results in its elimination from the portfolio. In addition to measures that allow the portfolio to meet emissions reductions goals, the Carbon Cap cases also include new investments in capacity resources (including 7,000 MW of new gas combustion turbines) to maintain reliability, as wind and solar provide limited value to meeting regional peak needs.
- The **Carbon Tax** scenarios have directionally similar impacts on investments and operations to the Carbon Cap scenarios; this result is to be expected since both scenarios apply a price to carbon emissions—the tax is explicit, while the cap is implicit. The levels of the proposed taxes studied in this analysis are sufficient to yield emissions approximately 70% emissions reductions.
- The **High RPS** scenarios provide a strong signal for investment in new renewables, which is reflected in the large quantities of new wind and solar selected in each of these portfolios. Under a 50% regional RPS goal, the total amount of new renewable generation selected to meet regional needs is 23,000 MW—18,000 MW above the Reference Case. A large share of the renewable generation in the High RPS scenarios is exported to neighboring regions, so while the higher RPS results in a large amount of additional zero-carbon generation, this new generation has a limited impact on the dispatch and associated emissions of existing coal plants in the Northwest portfolio. The High RPS scenarios also result in a dramatic increase in the amount of renewable curtailment observed, as the large buildout of wind resources exacerbates spring oversupply events
- In the **No New Gas** scenario, the prohibition on new investments in natural gas generation results in large new investments in energy storage to meet the region's growing capacity needs. A combination of battery and pumped storage resources (6,800 MW in total) are selected to provide the region with enough firm capacity to meet peak demands in the absence of new gas investments. However, the new investments identified in this study under a No New Gas scenario may not adhere to regional reliability standards: while energy storage may contribute to meeting peak hourly demands, its ability to generate over a sustained period during a critical water year—perhaps the most challenging reliability event in the Northwest—is limited by its duration.

Figure iii. Cumulative new generation capacity by 2050, Core Policy scenarios



The 'Selected Resources' snapshots show the cumulative new investments in generation resources identified under each policy scenario. These resources are added to the existing resources in the Core Northwest portfolio, which include existing nuclear, hydro, and renewable resources; existing coal plants net of announced retirements; and existing gas generators net of several anticipated retirements.

Figure iv. Annual generation mix in 2050, Core Policy scenarios

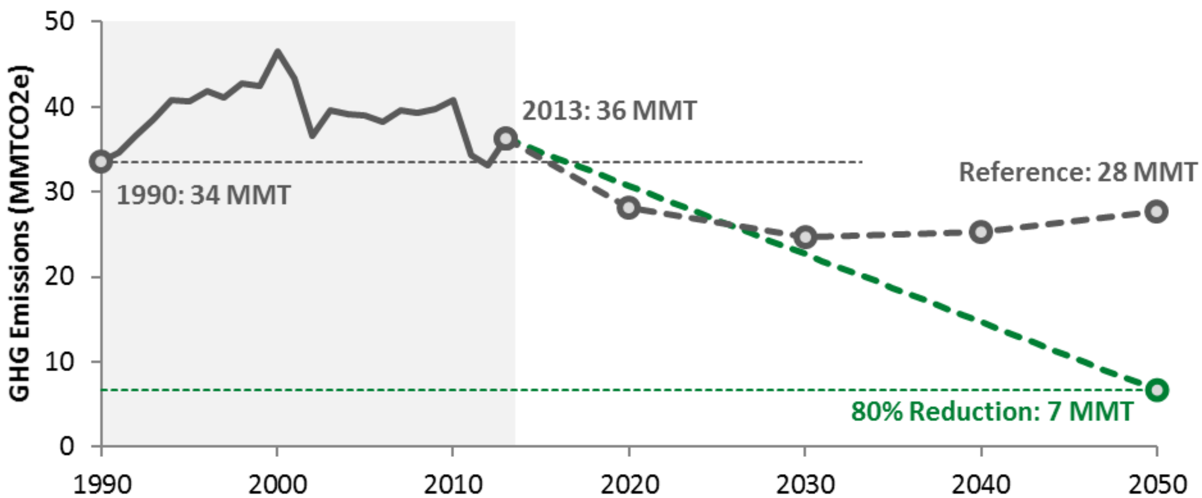


The 'Annual Generation Mix' compares the annual production of the total fleet of generation resources to the regional load (indicated by the black line on each graph). Regional total generation exceeds load in all cases, implying that the Northwest remains a net exporter of generation over the course of the year.

Cost & Emissions Impacts

As shown in Figure v, the Reference Case result in a reduction in greenhouse gas emissions relative to historical levels—due to both the anticipated retirement of coal plants and additions of renewables to meet existing RPS statutes—but an additional 21 million metric tons of reductions are needed to meet an emissions reductions goal within the electric sector of 80% relative to 1990 levels.

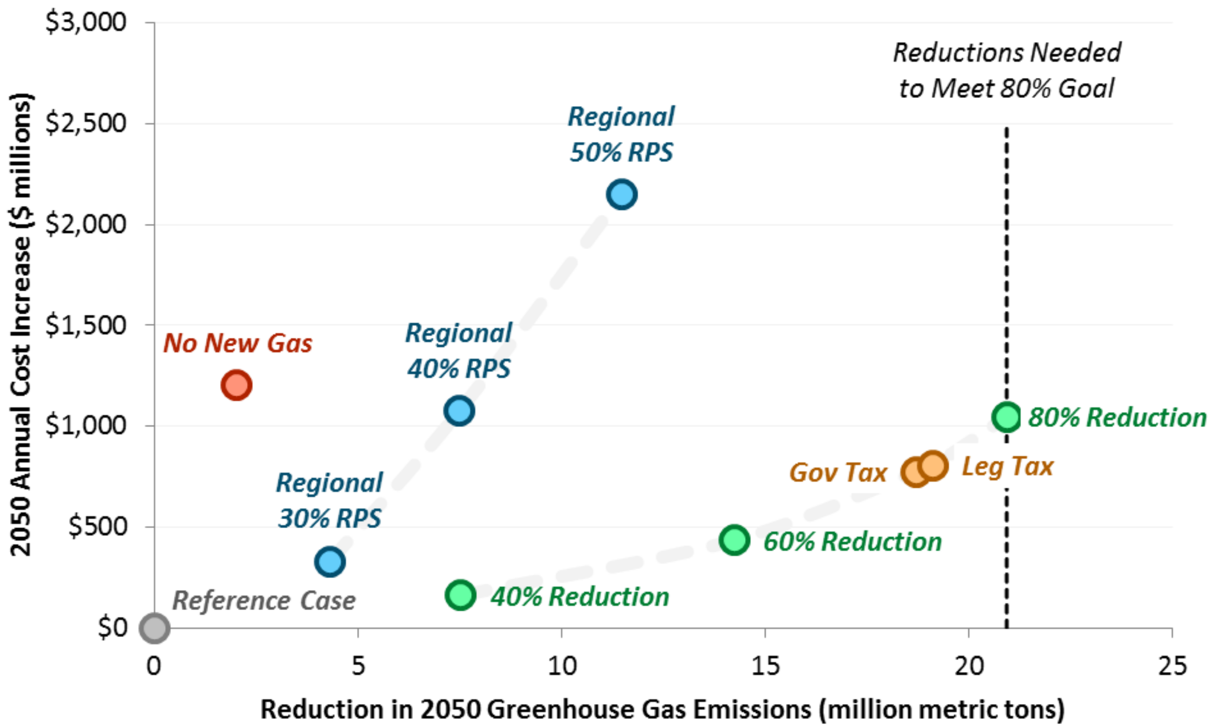
Figure v. Emissions trajectory for the Reference Case



The primary metrics used to compare the performance of each of the Core Policy scenarios are (1) the 2050 emissions reductions, measured relative to the Reference Case; and (2) the corresponding 2050 incremental total cost relative to the Reference Case.[2] Figure vi summarizes the performance of each of the Core Policy scenarios in each of these two dimensions.

[2] The total system revenue requirement for the Core Northwest region in the Reference Case is estimated to be $18.4 billion per year in 2050.

Figure vi. Summary of cost & emissions impacts relative to the Reference Case, 2050



Each of the types of policies considered yields a different combination of incremental greenhouse gas reductions and incremental cost:

+ The **Carbon Cap** scenarios define an efficient frontier for the least-cost policies to achieve emissions reduction goals. Meeting the 80% reduction goal, requiring 21 million metric tons of carbon reductions, by 2050 can be achieved at an incremental cost of approximately $1 billion per year.
+ The **Carbon Tax** scenarios lie along this efficient frontier; this is largely consistent with microeconomic theory that both a cap and a price can be used to achieve a least-cost portfolio of

emissions reductions.[3] The tax levels modeled in this study ($61/tonne and $75/tonne) are each sufficiently high to yield approximately 70% emissions reductions by 2050.

+ In comparison to the scenarios driven by carbon pricing, the **High RPS** scenarios result in significantly higher cost while yielding significantly lower greenhouse gas reductions. The cost of the 50% RPS case—over $2 billion per year—is more than double the 80% Reduction scenario, while the emissions reductions that it yields—11 million metric tons per year—are roughly half of what is needed to reach the 80% reduction target.
+ The **No New Gas** case offers the least effective mechanism for addressing greenhouse gas emissions within the region: the investments in energy storage made in place of new natural gas come at a significant cost premium but produce no carbon free generation. The incremental cost of the No New Gas case ($1.2 billion per year in 2050) is roughly equivalent to the cost of achieving the 80% reduction goal, yet it provides less than one tenth the emissions reductions needed to meet that goal.

Operational Impacts & Renewable Integration

The portfolios developed under the Core Policy scenarios span a wide range of renewable penetration, ranging from the 20% RPS (Reference Case) to 50% RPS. This wide range highlights how increasing penetrations of renewables will impact system operations in the Northwest region, and, in particular, the emerging role of renewable curtailment as a crucial tool to manage the variability of renewables at high penetrations. While all scenarios show some amount of renewable curtailment, the High RPS scenarios, which span the largest range in renewable penetration, provide the best illustration of the role of renewable curtailment at higher renewable penetration. Figure vii shows a snapshot of hourly operations in each of the High RPS scenarios on a day with high hydro conditions, demonstrating the growing magnitude of renewable curtailment at increasing penetrations. These types of events become much

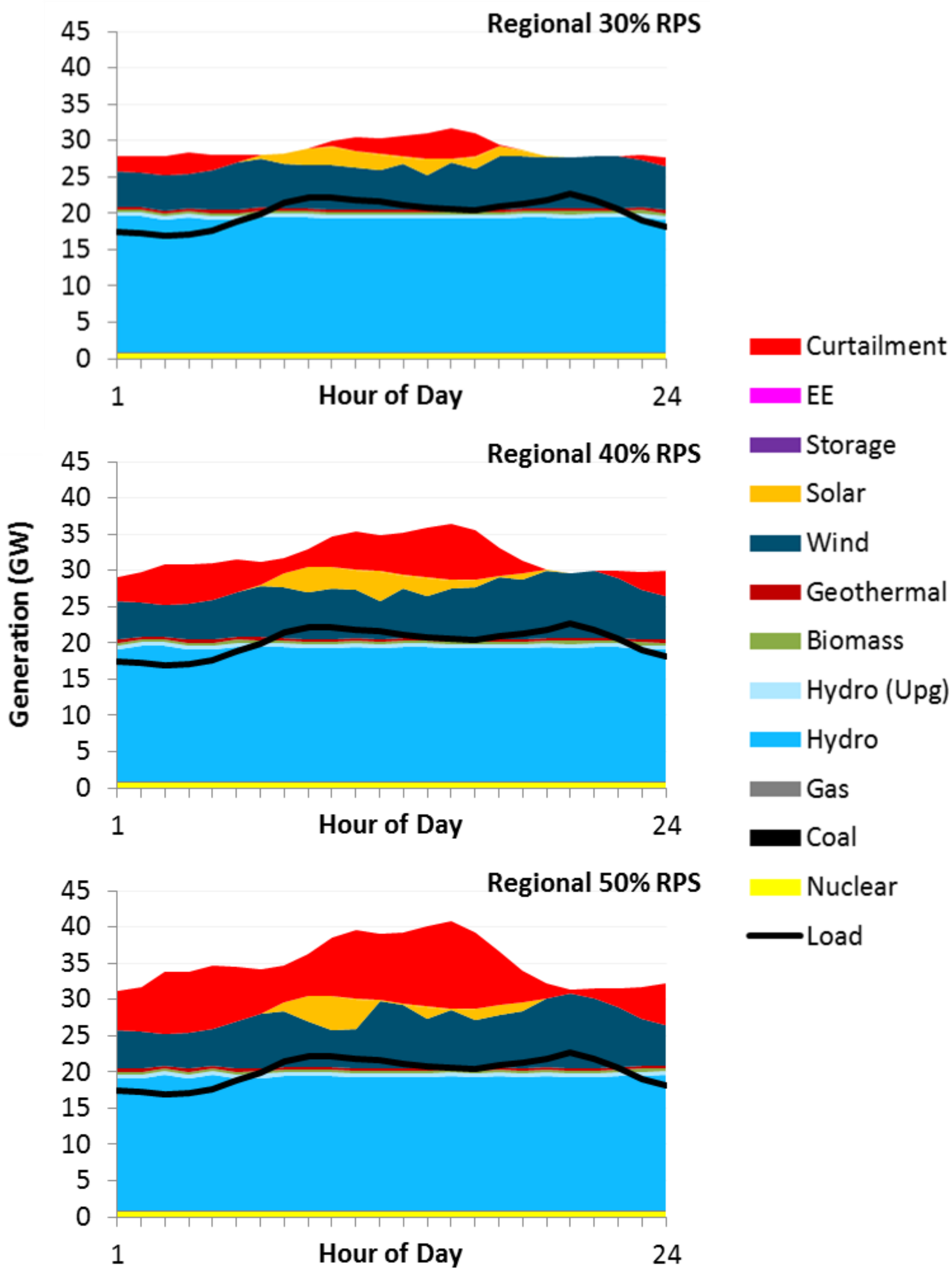
[33] While both policies can be used to achieve least-cost emissions reductions, they do not provide the same market signals

more frequent and larger in magnitude as RPS policy increases: as the RPS policy increases from 20% (Reference Case) to 50%, the percentage of available renewable generation that is curtailed annually increases from 4% to 9%.

While this study's finding regarding the critical role of renewable curtailment is consistent with a range of studies of high renewable penetrations in other jurisdictions, the character of the renewable curtailment dynamics observed in this study are distinctly different from other areas and reflect the unique characteristics of the Pacific Northwest electricity system. In particular, the characteristics of curtailment events observed in the Pacific Northwest are distinctly different from those anticipated in California at high renewable penetrations. While the expected patterns of curtailment in California are likely to be driven by high penetrations of solar PV and will generally coincide with the hours of maximum solar PV production each day, curtailment events in the Pacific Northwest will be driven by high combined output from the hydro system and wind fleet, lasting for much longer periods—days, weeks, or event months depending on the underlying hydro conditions.

The distinctive daily and seasonal patterns of curtailment characteristic to a region with significant hydro and wind resources explains why this study identifies limited value for new investments in energy storage as a facilitating technology for high renewable penetrations. This finding again distinguishes the Pacific Northwest from California, where previous analyses have identified significant potential value in new investments in energy storage to facilitate California's achievement of high renewable policy goals. The reason for this distinction is rooted in the different characteristics of curtailment events. In California, curtailment events are expected to last on the order of four to eight hours during periods of oversupply and will recur on a daily basis—a dynamic well-suited to balancing with energy storage technologies. In contrast, such storage devices would find infrequent opportunities to cycle in the Northwest, as curtailment events with less predictability and significantly longer duration do not lend themselves to balancing with relatively short duration storage.

Figure vii. Increasing renewable curtailment observed with increasing regional RPS goals



Selected Sensitivity Results

This study also considers a range of sensitivities on the policy scenarios, both to quantify the impact of future uncertainties on the findings drawn from this analysis and to highlight other key factors that impact the decarbonization of the electric sector. In general, the sensitivity analyses reinforce the study's findings that a least-cost pathway to decarbonizing the electric sector can be achieved through a technology-neutral policy that encourages a shift away from coal and towards a combination of gas, renewables and efficiency; as well as the idea that policies that target emissions reductions through specific technology requirements are less effective and more costly. The full suite of sensitivities examined in this study is listed in Table iii; results from the highlighted entries are discussed below due to their relevance to the study's conclusions.

Table iii. Inventory of sensitivities explored in analysis

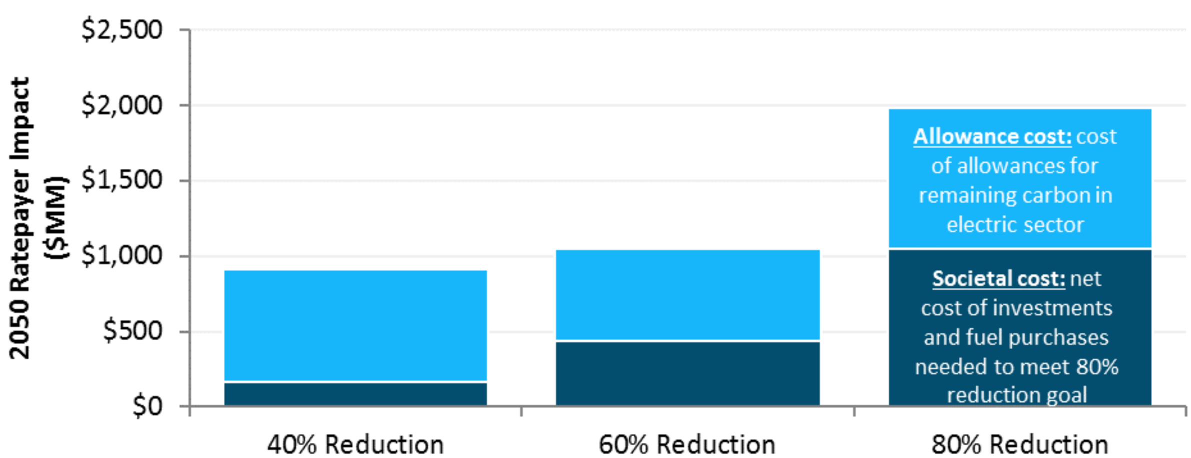
Sensitivity	Description
No Revenue Recycling	Examine impact to ratepayers if revenue collected under carbon pricing mechanism is not returned to the electricity sector
Loss of Existing Carbon Free Resource	Examine the cost and GHG implications of decommissioning existing hydro and nuclear generation
High EE Potential	Examine the potential role of higher-cost energy efficiency measures in a GHG-constrained future
High Electric Vehicle Adoption	Explore the role of vehicle as a potential strategy for reducing GHG emissions in the transportation sector
High & Low Gas Prices	Examine sensitivity of key learnings to assumptions on future natural gas prices
Low Technology Costs	Explore changes in cost and portfolio composition under assumptions of lower costs for solar, wind and energy storage
California 100% RPS	Explore implications of California clean energy policy on decarbonization in the Northwest

NO REVENUE RECYCLING

In the incremental costs attributed to the Carbon Cap and Carbon Tax scenarios, this study assumes revenue neutrality of carbon pricing scenarios within the electric sector—that is, revenues raised through carbon pricing are returned to electric ratepayers to offset the costs of purchasing allowances (or paying a carbon tax). In this respect, the incremental cost of each scenario reflects the cost of new investments in low-carbon generation and operating costs of dispatching lower-carbon fuels—the societal cost of achieving emissions reductions within the electric sector. In recognition of the possibility that a carbon pricing policy could divert tax or allowance revenues to other uses, this sensitivity quantifies the potential additional costs to electric ratepayers.

A decision not to recycle a share of revenues back to the electric sector would result in a significant increase in the cost borne by the electric sector to decarbonize. In the 80% Reduction scenario, this would result in nearly a doubling of the cost borne by electric ratepayers, increasing the total cost from $1.1 billion per year to $2.0 billion per year; the relative impact is even larger at the lesser carbon targets. The impact of the choice to use carbon allowance/tax revenues for other purposes is shown in Figure viii.

Figure viii. Impact of "No Revenue Recycling" sensitivity on Carbon Cap incremental costs



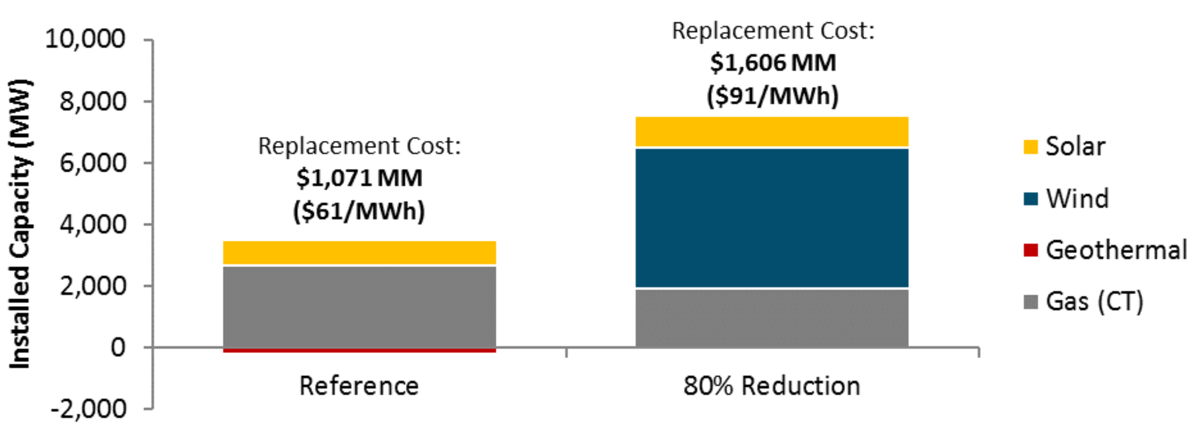
EXISTING RESOURCE RETIREMENT

This sensitivity explores how the retirement of 2,000 aMW of existing zero-carbon generation would impact the cost of meeting the region's greenhouse gas goals, quantifying the incremental operating and investment costs to replace it under the Reference Case and the 80% Reduction scenario. The cost to replace these existing resources provides a measure of their value under each policy. Figure ix summarizes the resources selected to replace this capacity under the Reference Case and the 80% Reduction scenario.

- In the **Reference Case**, with no formal or organized greenhouse gas policy, retiring resources are replaced with new gas capacity and energy. The cost to replace the resources is roughly **$1 billion** per year, representing the cost of a natural gas benchmark (or market energy and capacity costs).
- In the **80% Reduction** scenario, the retiring resources are replaced with carbon-free generation, requiring 5,500 MW of new renewables; at the same time, 2,000 MW of new gas capacity is needed for resource adequacy. In total, the carbon-free replacement cost is **$1.6 billion per year**.

In the context of meeting greenhouse gas reductions goals, the value of these resources is understated by current policy and is significantly higher than today's wholesale prices imply; policies that encourage the retention of these resources will be crucial to meeting reduction goals.

Figure ix. Additional resources selected to replace 2,000 aMW of existing hydro & nuclear



Key Findings & Conclusions

The scenario and sensitivity analysis conducted in this study inform a number of conclusions regarding the most cost-effective means to achieve regional greenhouse gas reduction goals within the electric sector. This section summarizes the most significant of these findings.

The most cost-effective opportunity for reducing carbon in the Northwest is to displace existing coal generation with a combination of energy efficiency, renewables and natural gas. Currently, coal resources account for roughly 80% of the Northwest's electricity-sector greenhouse gas emissions. Although planned retirements of several regional coal plants will help reduce emissions, the remaining coal plants owned by utilities in the region will continue to produce significant greenhouse gas emissions if they continue to operate. Replacing remaining existing coal resources with a low-carbon combination of natural gas, renewable generation, and energy efficiency provides significant greenhouse gas reductions at moderate incremental cost to ratepayers: the least-cost portfolio that meets the region's 80% reduction goals eliminates coal from the portfolio at a total cost of $1 billion per year—an increase of about 6% and an average abatement cost of $50/tonne. To encourage this transition, a technology-neutral policy that focuses directly on carbon provides a consistent and universal market signal to displace coal with the least-cost mix of low- and zero-carbon resources.

Renewable generation is an important component of a low-carbon future, but using a Renewables Portfolio Standard to drive investments in renewables results in higher costs and higher carbon emissions than a policy that focuses directly on carbon. RPS policy—a mandate for renewable procurement—has been successful at driving investment in renewables in the Northwest and throughout the United States. However, it ignores the potential contributions of other greenhouse gas abatement options in the electric sector, such as energy efficiency and coal-to-gas switching. Further, at higher levels of renewable penetration, RPS policies lead to unintended consequences and introduce distortions into wholesale markets—specifically, negative market pricing during periods of renewable curtailment—

creating adverse market conditions and reducing market revenues for other existing zero-carbon resources. Distortionary impact of RPS policy on wholesale prices makes the decision to reinvest and maintain these resources difficult notwithstanding their long-term value to meeting carbon goals. Ultimately, existing hydro and nuclear generators may not be able to justify continued operations if these effects become significant enough.

Meeting decarbonization goals becomes significantly more challenging and costly should existing zero-carbon resources retire. The existence of the region's zero-carbon generation fleet, comprising 31,000 MW of hydroelectric capacity and 1,200 MW of nuclear, is the foundation of the Northwest electric sector's low carbon intensity. However, these zero-carbon resources will face relicensing decisions, equipment reinvestment costs, and continued maintenance costs between now and 2050, with no guarantee that they will continue to operate. Should a portion of the existing zero-carbon fleet retire, the challenge and costs of meeting long-term decarbonization goals in the electricity sector increases significantly, as both the energy and firm capacity of these retiring resources must be replaced. In this study, replacing 3,400 MW of existing hydro or nuclear generation would require nearly 5,500 MW of new wind and solar generation as well as 2,000 MW of natural gas peaking at an annual cost of $1.6 billion by 2050. A policy that therefore encourages the retention of and reinvestment in low-cost existing zero-carbon generation resources will help contain costs of meeting carbon goals.

Prohibiting the construction of new natural gas generation results in significant additional cost to Northwest ratepayers without a significant greenhouse gas reduction benefit. This study affirms the findings of previous regional planning efforts that new investment in firm resource capacity will be needed in the region in the coming decade to ensure resource adequacy. Its results also suggest that natural gas—and specifically investment in new natural gas capacity—has an important role to play as part of a least-cost resource portfolio even under stringent greenhouse gas regulation. Future regional capacity needs can be met at relatively low cost—and with little absolute impact on greenhouse gas emissions—with new investments in low-cost gas peaking units. Because these types of units are built with the expectation of operating infrequently—generally only when needed to meet peak demands—their absolute contribution to greenhouse gas emissions is minimal. Alternatively, meeting regional resource adequacy needs exclusively with non-emitting resources will likely increase costs to ratepayers without providing a material greenhouse gas benefit. The contrast between these scenarios highlights the key finding that investments in natural gas do not inherently conflict with ambitious greenhouse gas reduction goals—in fact, investments in new natural gas generation may be pivotal to achieving emissions reductions goals reliably and at least cost.

Returning revenues raised under a carbon pricing policy to the electricity sector is crucial to mitigate higher costs to ratepayers. This study demonstrates a least-cost pathway to deep decarbonization in the electric sector in the Northwest at a moderate cost of $1 billion per year—a figure that reflects the costs of new investments and low-carbon fuel to reach this goal—and identifies carbon pricing policies as a mechanism to promote this transition efficiently. However, if a carbon pricing scheme is designed without revenue recycling to electric ratepayers, the cost of such a policy to electric ratepayers will be considerably larger, as ratepayers will bear not only the costs to invest in decarbonization but will face additional costs to purchase allowances (or pay taxes) for the remaining emissions in the electric sector. This effect could increase the cost to meet the 80% reduction goal by as much as $1 billion, doubling the costs borne by ratepayers without providing any incremental emissions reductions benefit. A carbon pricing scheme that returns a large share of the revenues raised from the electric sector back to electric ratepayers in the form of bill credits or investment credits will help contain the ratepayer impacts of meeting carbon reduction goals within the electric sector and is a common feature of carbon pricing programs adopted in other jurisdictions.

Research and development is needed for the next generation of energy efficiency measures. One of the four pillars of deep decarbonization is the need to meet ambitious conservation goals. While the region's past acquisition of conservation is a success story for mitigating load growth, the establishment of long-term carbon targets points toward the need for an evolved perspective on energy efficiency, its value, and what utilities are willing to pay to acquire it. This study demonstrates not only that measures identified by NWPCC as not cost-effective under current policy become cost-effective as a component of the least-cost greenhouse gas reduction portfolio, but that additional high-cost measures beyond today's cost-effectiveness threshold could further contribute to meeting these goals, reducing the need for new investments in renewables. Thus, while NWPCC's work to quantify the low-cost conservation potential for existing resources has laid a strong foundation for future conservation programs, research and development in the region should focus on continuing to expand the technological options available to mitigate future load growth. At the same time, promoting energy efficiency is a question for policymakers as well, as the avoided costs used to assess cost-effectiveness directly reflect state energy policies—in this respect, a carbon pricing policy lays a foundation for an energy efficiency cost-effectiveness framework that captures the inherent value of the greenhouse gas reductions that conservation provides.

Vehicle electrification is a low-cost measure for reducing carbon emissions in the transportation sector. While this study's primary focus is on how policy can most effectively facilitate carbon reductions in the electric sector, deep decarbonization literature indicates that achieving economy-wide reductions will also require the electric sector to meet new loads as transportation and buildings electrify. This study highlights vehicle electrification as one cross-sectoral opportunity to achieve economy-wide greenhouse gas reductions that not only reduces carbon but also provides net benefits to society as a whole. In this respect, transportation electrification is a least-regrets strategy for carbon abatement, but one that will require careful consideration due to impacts across multiple sectors of the economy. Additional work is needed within the region to explore how transportation electrification—and potentially electrification of other end uses—can be achieved to reduce carbon without placing undue incremental cost burdens on the electric sector as large new quantities of load materialize.

1 Introduction

1.1 Study Motivation

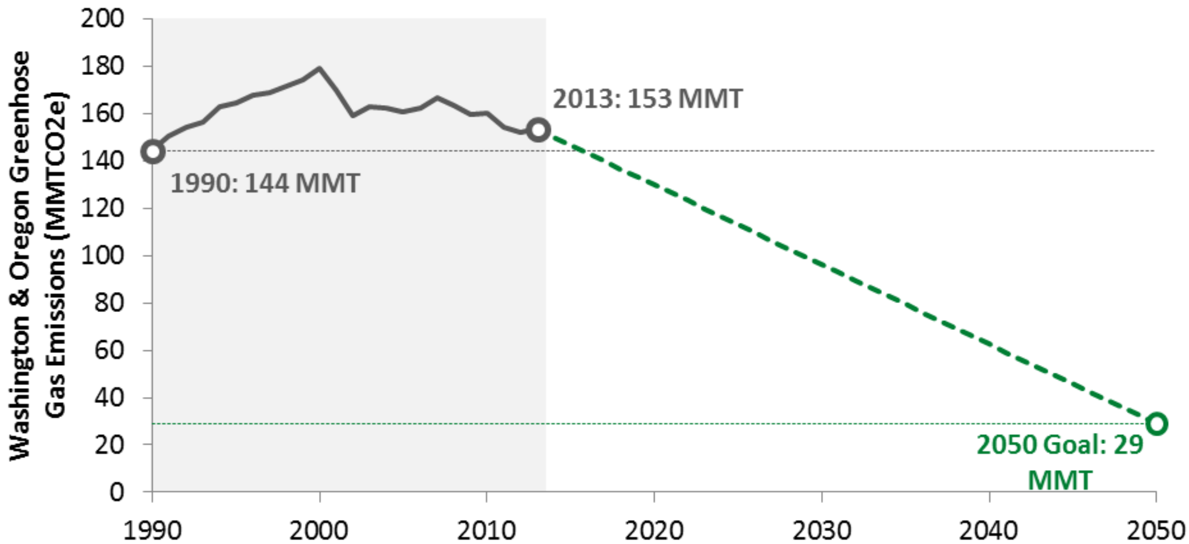
In the past year, both Washington and Oregon have considered expanding existing greenhouse gas reductions targets to establish goals for long-term deep decarbonization:

+ In Washington, the Department of Ecology has established long-term greenhouse gas reductions goals for the state. Washington's current targets, established in 2008, require the state to reduce emissions by 25% relative to 1990 levels by 2035 and 50% by 2050. In 2016, based on Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report and a review of targets established by other jurisdictions, the Department of Ecology proposed a revision to existing targets that would require a **40% reduction below 1990 levels by 2035** and an **80% reduction by 2050**;[4]
+ In Oregon, House Bill 3543, passed in 2007, established long-term greenhouse gas reductions targets for the state of a 10% reduction below 1990 levels by 2020 and a 75% reduction by 2050. In 2017, legislation was introduced to increase these targets to a **68% reduction by 2035** and a **91% reduction by 2050**. Current cap-and-trade legislation under consideration would require and 80% reduction below 1990 levels by 2050.

As shown in Figure 1-1, achieving an 80% reduction goal across the two combined states would require economy-wide emissions reductions of 124 million metric tons between 2013 and 2050.

[4] Described in *Washington Greenhouse Gas Emission Reduction Limits*, available at: https://fortress.wa.gov/ecy/publications/documents/1601010.pdf

Figure 1-1. Trajectory to meet 80% economy-wide greenhouse gas emissions reduction goal, Washington and Oregon



These deep decarbonization goals are ambitious. Their adoption and implementation should be accompanied by careful consideration of how they could best be achieved while moderating the costs. This study seeks to contribute to the discussion on how to meet the Pacific Northwest's deep decarbonization goals by exploring how the region's electric sector could most effectively and efficiently contribute to the achievement of emissions reduction goals.

1.2 Deep Decarbonization Background

1.2.1 LESSONS FROM OTHER STUDIES

Growing interest in understanding the possible technology pathways and policy strategies for achieving deeply decarbonized energy systems and economies by mid-century has prompted a number of quantitative and qualitative "deep decarbonization" studies, which provide important context for this study. These studies include:

+ **Deep Decarbonization Pathways for Washington State[5]:** a 2017 study commissioned by the Washington Governor's office and completed by Evolved Energy Research highlights several potential pathways to meet 80% economy-wide reduction goals within the state of Washington. The study explored multiple scenarios to achieve goals, including: (1) electrification, (2) renewable pipeline, and (3) innovation. Across all scenarios, the study finds that "Energy efficiency, decarbonization of electricity and switching to electric sources are common strategies."
+ **California PATHWAYS[6]**: California state agencies commissioned E3 to study possible pathways to the state's 2050 80% reduction goal, and to inform the setting of a 2030 goal. The study identified five strategies as being critical to meeting longer-term greenhouse gas emissions reduction goals: (1) significant increases in energy end-use efficiency, (2) fuel switching away from fossil fuels for vehicles and buildings, (3) sustained decarbonization of the electricity sector, (4) low-carbon fuels, and (5) reductions in non-energy greenhouse gas emissions.
+ **Pathways to Deep Decarbonization in the United States[7]:** undertaken as part of the Deep Decarbonization Pathways Project (DDPP), a global initiative led by the Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI), this study establishes the feasibility of meeting an 80% reduction goal across the United States at an incremental cost of 1% of gross domestic product (GDP). The study examines scenarios—High Renewable, High Nuclear, High CCS, and Mixed—to demonstrate the existence of a multiple technology pathways to deep decarbonization.
+ **United States Mid-Century Strategy for Deep Decarbonization[8]:** published by the White House in 2016, this study identifies three broad strategies needed to meet carbon goals: (1) decarbonizing the energy system; (2) sequestering carbon, including CO2 removal technologies;

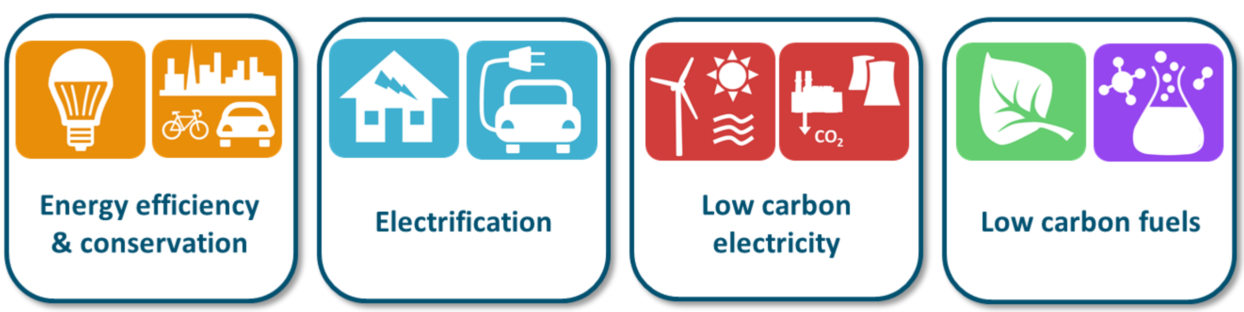
[5] Available at: http://www.governor.wa.gov/sites/default/files/Deep_Decarbonization_Pathways_Analysis_for_Washington_State.pdf
[6] Available at: http://www.ethree.com/wp-content/uploads/2017/02/E3_PATHWAYS_GHG_Scenarios_Updated_April2015.pdf
[7] Available at: http://unsdsn.org/wp-content/uploads/2014/09/US-Deep-Decarbonization-Report.pdf
[8] Available at: https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf

and (3) reducing non-CO2 emissions. As part of a focused look at how to decarbonize the energy system, this study emphasizes cutting energy waste, decarbonizing electricity, and shifting other end uses to electricity as a means of providing low carbon primary energy.

While these studies have taken on a variety of different geographic scopes—national, state-level, and local—most studies have converged upon a set of four foundational elements needed to meet deep decarbonization goals across the economy. These four "pillars"—summarized in Figure 1-2—include:

+ Deployment of ambitious levels of **energy efficiency and conservation** beyond levels of historical achievement;
+ **Electrification** of end uses traditionally fueled by fossil fuels, including vehicles, space and water heating, and industrial processes;
+ Production of **low carbon electricity** to supply clean energy to both existing and newly electrified loads; and
+ Use of **low-carbon fuels**—for instance, biofuels, synthetic gas, and/or hydrogen—to supply energy to end uses that continue to rely on liquid and/or gaseous fuels.

Figure 1-2. Four pillars of deep decarbonization



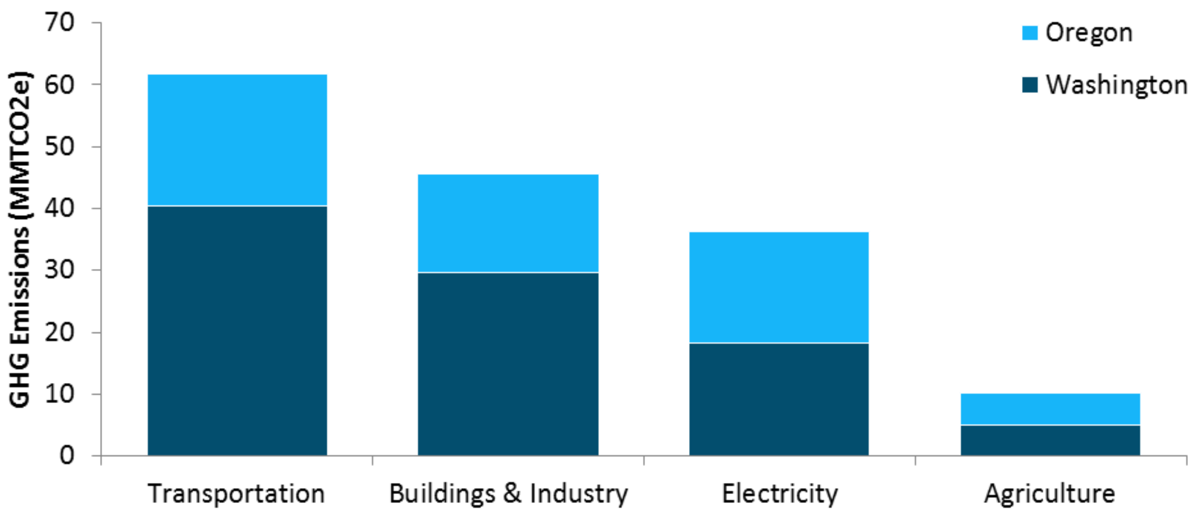
The four pillars provide a rough blueprint for the development of a comprehensive plan for deep decarbonization across an economy, while also highlighting the central role of the electric sector in meeting those goals: deep economy-wide reductions in greenhouse gas emissions will require the electric sector not only to transition almost entirely to zero-carbon generation sources, but to do so while meeting growing demand for electricity as current fossil-fueled end uses (transportation, buildings, industry) switch to electricity.

1.2.2 DECARBONIZATION PATHWAYS IN THE NORTHWEST

The four pillars also provide a useful lens through which to evaluate opportunities for greenhouse gas reductions in the Pacific Northwest. Figure 1-3 shows a sectoral breakdown of the emissions inventories for Washington and Oregon in 2013. Together, transportation and "buildings and industry"[9] account for roughly 70% of the greenhouse gas emissions within the region. In contrast, electricity generation accounts for only 23% of regional greenhouse gas emissions, due to the significant contributions of existing hydro and nuclear to the regional generation mix.

[9] The category "buildings and industry" captures the direct combustion of fuels in buildings and industry but excludes the emissions associated with electricity consumption, which is captured in the "electricity" category.

Figure 1-3. Summary of 2013 GHG inventories for Washington and Oregon[10]



A comprehensive and successful long-term emissions reduction strategy in the Northwest will therefore likely include the following elements:

- A combination of measures and policies that directly target emissions reductions in transportation, buildings, and industry, which will likely include aggressive combinations of efficiency, electrification, and clean fuels deployment;
- Efforts to facilitate coordination among industries to allow cross-sectoral greenhouse gas reduction measures, such as electrification;
- Market transformation programs to encourage development of the next generation of energy efficiency opportunities and to reduce costs of other existing decarbonization options; and

[10] The data shown in this chart is obtained from recent greenhouse gas emissions inventory produced by each state: *Report to the Legislature on Washington Greenhouse Gas Emissions Inventory: 2010 – 2013* (available at: **https://fortress.wa.gov/ecy/publications/documents/1602025.pdf**) and *Oregon Greenhouse Gas In-boundary Inventory* (available at: **http://www.oregon.gov/deq/FilterDocs/GHGInventory.pdf**)

- Policies that encourage a transition to a low-carbon grid within the Northwest, reducing current emissions to levels significantly below 1990.

Although the general policy framework for deep decarbonization may be similar across regions, the Pacific Northwest has several features, particularly in the electricity sector, that distinguish it from other regions in the U.S. and are important to consider in developing appropriate deep decarbonization pathways or the region. In the electricity sector, these unique features include:

- Significant reliance on hydroelectric generation to meet regional loads;
- Electric rates that are kept low by secondary revenues from surplus hydro sales;
- Historical emphasis on conservation and energy efficiency.

1.3 Study Overview

While recognizing the ultimate need for a comprehensive and economy-wide strategy to meet long-term decarbonization goals, this study takes on a more limited scope, focusing primarily the question of what policies most effectively promote decarbonization within the electricity sector. By adopting a narrower focus, the intent of this study is to evaluate the implications of specific policy mechanisms on the electricity sector's ability to achieve its own decarbonization at least-cost, providing a foundation for subsequent analysis to examine cross-sectoral and economy-wide decarbonization strategies. The three main questions addressed in this study are:

- What combination of generation resources will provide the most cost-effective sources of greenhouse gas reductions within the electric sector while meeting reliability needs?
- What types of policies will enable the achievement of emissions reductions goals in the electric sector at least cost?

- How will different policies impact the long-term viability of existing low-carbon resources in the Northwest, including hydro, nuclear, and energy efficiency?

This study relies on scenario analysis using E3's RESOLVE model, an optimal capacity expansion model with a detailed hourly simulation of system operations, to evaluate the implications of a variety of different policies in terms of both their effectiveness at reducing carbon emissions within the electric sector and their cost impacts for electric ratepayers. RESOLVE is designed to optimize portfolios under high penetrations of variable generation with the capability to model explicitly a variety of different types of prospective policies, including higher Renewables Portfolio Standards (RPS), carbon cap and trade programs, carbon taxes, and prohibitions on new investments in fossil fueled generation. Through scenario analysis of these alternative policies, this study highlights their relative effectiveness with respect to meeting long-term decarbonization goals.

1.4 Relationship to Existing Regional Planning Processes

Throughout the Pacific Northwest, electricity resource planning is broadly distributed among a handful of entities. In addition to the integrated resource plans completed by investor- and consumer-owned utilities, several regional entities conduct planning exercises meant to inform the electric sector. These include the development of regional power plans by the Northwest Power and Conservation Council (NWPCC), electric sector resource planning for the federal hydroelectric system conducted by the Bonneville Power Administration (BPA), and a regional loads and resources outlook compiled by the Pacific Northwest Utilities Conference Committee (PNUCC).

This study is distinct from these existing planning exercises, both in its purpose and scope: whereas most of these planning exercises generally focus on the near- and mid-term needs of the electric system to inform choices made by utilities within the region, this study takes a longer-term perspective with the intention of providing a compass for policymakers to understand the long-term challenges of electricity system decarbonization. In this respect, this study is not intended as a substitute or replacement for existing electricity resource planning processes. Nonetheless, the type of analysis used in this study has significant overlap with the analyses typically conducted in these existing planning processes. To ensure that the results of this work are most relevant to decision-makers within the region, this study relies upon the existing ecosystem of resource planning studies for inputs and assumptions where possible. In turn, the results of this study tend to echo key findings and conclusions established by prior plans. This section summarizes the key findings of each of these plans, which serve to establish the foundation for the analysis conducted by the study.

1.4.1 SEVENTH POWER PLAN (NWPCC)

In 1980, the United States government passed the Pacific Northwest Electric Power Planning and Conservation Act, establishing the charter for the NWPCC and tasking it with creating a regional 20-year plan for the electric sector to be updated every five years. Congress directed the NWPCC to develop regional electricity plans to maximize use of cost-effective conservation to defer new investments in generation and that complied the region's preferences to manage its endowment of hydroelectric power with environmental stewardship. The NWPCC's Seventh Power Plan,[11] spanning the period 2015-2035, was adopted on February 11, 2016. A number of this plan's key findings are relative to this work:

+ **Acquisition of cost-effective energy efficiency remains the least-cost resource.** The utilities of the Pacific Northwest have long emphasized the role of energy efficiency in the development of resource plans, which has helped to limit regional load growth. Going forward, the Seventh Power Plan indicates that all incremental energy needs through 2026 could be met by cost-effective energy efficiency—up to 2,700 aMW throughout the region.
+ **New capacity investments will likely be needed to meet regional peak demand by 2030** due to anticipated coal plant retirements. Cost-effective energy efficiency and demand response can

[11] Available at: https://www.nwcouncil.org/energy/powerplan/7/plan/

mitigate need for new generation investment, but additional capacity will likely be needed. In this case, investments in new natural gas generation capacity—which are expected to run a very low capacity factors—appear to be the least-cost option to satisfy this need.

+ With respect to carbon, the Seventh Power Plan indicates that current policy will result in greenhouse gas emissions reductions relative to current levels. The plan identifies retirement of remaining coal plants and replacement with a combination of efficiency and natural gas as the least-cost option to achieve further emissions reductions.

In addition to these findings, the Seventh Power Plan contains many additional insights and useful information, much of which was integrated directly into this study to enhance its quality.

1.4.2 POWER SUPPLY ADEQUACY ASSESSMENT (NWPCC)

NWPCC also annually prepares an assessment of the adequacy of regional electricity supply to meet electric loads in the near-term (five years ahead) using loss-of-load-probability modeling to assess the resource adequacy. In 2017, NWPCC completed the *Pacific Northwest Power Supply Adequacy Assessment for 2022*,[12] which underscores the findings of the Seventh Power Plan that coal plant retirements will create a need for new generation capacity within the region in the near term. The most recent assessment concludes that by 2021, the regional will fail to meet the loss-of-load probability (LOLP) standard established by the NWPCC, needing up to 400 MW of new generation capacity to maintain reliability (after assuming achievement of all cost-effective energy efficiency).

1.4.3 WHITE BOOK (BPA)

As administrator of the federal hydro system, BPA publishes its White Book annually, providing a ten-year outlook comparing projections of regional retail load, contract obligations, and resource capabilities. The

[12] Available at: https://www.nwcouncil.org/energy/resource/2017-5/

White Book includes both a comparison of BPA's obligations to its customers with its resource portfolio, as well as a broader regional assessment of supply-demand balance within the region. The 2016 White Book,[13] which considers the period from 2018-2027, includes a similar outlook to the Seventh Power Plan on the regional balance between loads and resources.

1.4.4 NORTHWEST REGIONAL FORECAST OF LOADS AND RESOURCES (PNUCC)

PNUCC is a consortium of Northwest investor- and consumer-owned utilities that acts a consolidated voice within the electric utility industry. Each year, PNUCC compiles resources plans from each of its member utilities to produce the *Northwest Regional Forecast of Loads and Resources,*[14] providing a ten-year outlook of the region's loads and resources. The key conclusion reached in the most recent regional assessment, which focuses on the period from 2018-2026, is that, with the anticipated retirements of Boardman, Centralia, Colstrip 1 and 2, and North Valmy beginning in 2021, the region's need for winter peaking capability may exceed the available existing firm resources. The *Northwest Regional* Forecast similarly echoes other interregional planning processes in its emphasis on the importance of the acquisition of cost-effective energy efficiency, which can contribute to the deferral of new investments in generation.

1.5 Report Contents

The remainder of this report is organized as follows:

+ **Section 2** describes the scenarios and modeling approach used in the study;
+ **Section 3** describes the key modeling inputs and assumptions that shape the analysis;

[13] Available at: https://www.bpa.gov/power/pgp/whitebook/2016/index.shtml
[14] Available at: http://www.pnucc.org/sites/default/files/file-uploads/2017%20PNUCC%20NRF.pdf

- **Section 4** presents portfolio results for each of the Core Policy scenarios;
- **Section 5** discusses implications based on the results of the Core Policy scenarios;
- **Section 6** presents the results of sensitivity analyses conducted to test the resilience of the study's findings to key sources of uncertainty; and
- **Section 7** summarizes the study's key findings and conclusions.

Additionally, several appendices with additional technical details are included:

- **Appendix A** describes the day sampling methodology used to populate RESOLVE with a sampling of days representative of expected distributions of load, wind, solar, and hydro conditions;
- **Appendix B** contains additional detail on inputs and assumptions used in this study**;**
- **Appendix C** presents detailed results for each scenario across the full time horizon of the modeling exercise (2020-2050).

2 Modeling Approach

2.1 RESOLVE Methodology

2.1.1 OVERVIEW

RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. At the same time, it means that emerging technologies that could play a role in a low-carbon future for the Northwest—for instance, small modular nuclear reactors—are not evaluated within this study. This modeling choice is not meant to suggest that such emerging technologies should not have a role in meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study. The full range of resource options considered by RESOLVE in this study is shown in Table 2-1.

Table 2-1. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines • Repowered CCGTs	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Geothermal • Hydro upgrades • Solar PV • Wind	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load
Energy Storage	• Batteries (>1 hr) • Pumped Storage (>12 hr)	• Stores excess energy for later dispatch • Contributes to meeting minimum generation and ramping constraints
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Interruptible tariff (ag) • DLC: space & water heating (res)	• Contributes to planning reserve margin needs

2.1.2 OPERATIONAL SIMULATION

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify traditional unit commitment problem where possible while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

+ **Hourly chronological simulation:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
+ **Aggregated generation classes:** rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas CCGT, gas CT). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
+ **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class' operations.
+ **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. RESOLVE includes six zones: the Core Northwest region and five external areas that represent the loads and resources of utilities throughout the rest of the Western Interconnection.
+ **Co-optimization of energy and ancillary services:** RESOLVE dispatches generation to meet load across the Western Interconnection while simultaneous reserving flexible capacity within the Primary Zone to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.
+ **Smart sampling of days:** whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the WECC system for 41 independent days. Load, wind, and solar profiles for these 41 days, sampled from the historical meteorological record of the period 2007-2009, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete

distributions of potential conditions; daily hydro conditions are sampled separately from low (2001), average (2005), and high (2011) hydro years to provide a complete distribution of potential hydro conditions.[15] This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the 41 days. The methodology used to select these days via optimization is further described in Appendix A.

+ **Hydro dispatch informed by historical operations:** RESOLVE captures the inherent limitations of the generation capability of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: (1) daily energy budgets, which limit the amount of hydro generation in a day;[16] (2) maximum and minimum hydro generation levels, which constrain the hourly hydro generation; and (3) maximum multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change its output across periods from one to four hours. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. The derivation of these constraints from actual hourly operations makes this representation of hydro operations conservative with respect to the amount of potential flexibility in the resource. Additional detail on the operational modeling of the hydro resource is discussed in Section 3.3.

2.1.3 ADDITIONAL CONSTRAINTS

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

[15] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. For further detail on the smart sampling algorithm used in RESOLVE, see Appendix A.

[16] Sometimes hydro operators can shift hydro energy from day to day: for example, if hydro operators know that tomorrow will be a peak day, they can save some hydro energy today and use them tomorrow to meet the system need. This flexibility can help integrating renewable into the system and it is going to be more and more valuable as the % of system renewable penetration increases. To capture this flexibility, model allows up to 5% of the hydro energy in each day to be shifted around within two months.

- **Planning reserve margin:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet 1-in-2 system peak plus additional 15% of planning reserve margin (PRM) requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours.
- **Renewables Portfolio Standard (RPS) requirement:** RPS requirements have become the most common policy mechanism in the United States to encourage renewable development. RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year.
- **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators.
- **Resource potential limitations:** Many potential new resources are limited in their potential for new development. This is particularly true for renewable resources such as wind and solar. RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio, imposing practical limitations on the amount of any one type of resource that may be developed.

RESOLVE considers each of these constraints simultaneously, selecting the combination of new generation resources that adheres to these constraints while minimizing the sum of investment and operational costs.

2.1.4 KEY MODEL OUTPUTS

RESOLVE produced a large amount of results from technology level unit commitment decisions to total GHG emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

+ **Total revenue requirement ($/yr):** The total revenue requirement reports the total costs incurred by utilities in the study footprint (the combination of Washington and Oregon) to provide service to its customers. This study focuses on the relative differences in revenue requirement among scenarios, generally measuring changes in the revenue requirement relative to the Reference Case. The cost impacts for each scenario comprise changes in fixed costs (capital & fixed O&M costs for new generation resources, incremental energy efficiency, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs, fuel costs, costs of market purchases and revenues from surplus sales).
+ **Greenhouse gas emissions (MMTCO2e):** This result summarizes the total annual GHG emission in the system with imports and exports adjustments. The GHG emission is one of the most important metrics for the studies. By comparing the GHG emission and total resource costs between different policy scenarios, we can conclude the relative effectiveness of policies in GHG reduction.
+ **Resource additions for each period (MW):** The selected investment summarizes the cumulative new generation capacity investments by resources types. It provides an overview of the what kinds of generation are built and the timing of the investments.
+ **Annual generation by resource type (aMW):** Energy balance shows the annual system load and energy produced by each resource type at ten-year intervals. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of resources are dispatched more? How do the dispatch behaviors change over the years? And how do curtailment, imports, and exports vary year by year?

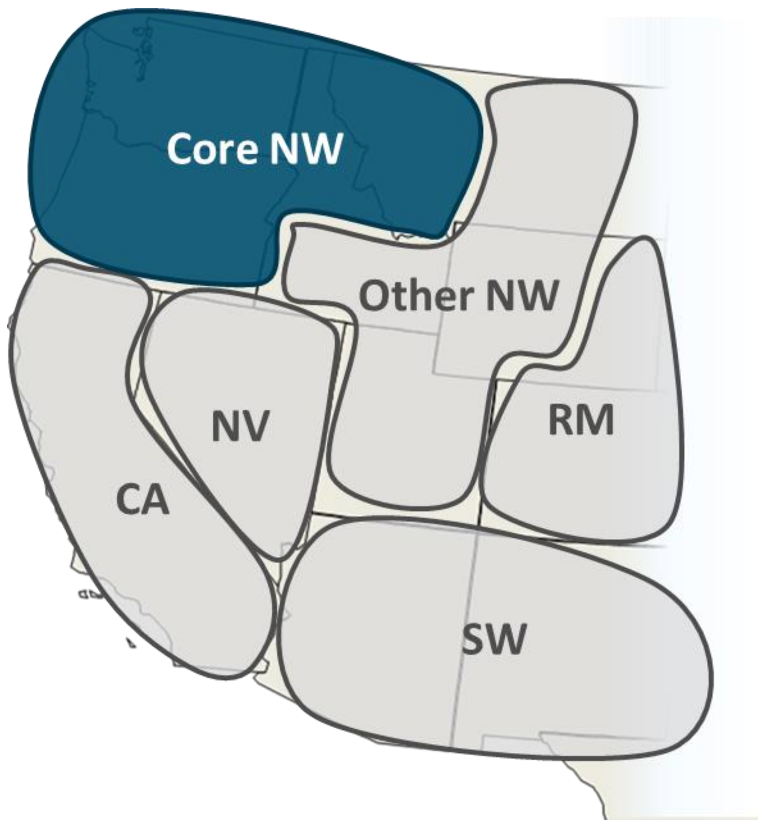
+ **Renewable curtailment (aMW):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.
+ **Wholesale market prices ($/MWh):** outputs from RESOLVE can be used to estimate wholesale market prices on an hourly basis (or during the standard HLH and LLH trading periods). As an optimization model, RESOLVE produces "shadow prices" in each hour that represent the marginal cost of generation given all the resources available at the time; these marginal costs serve as a proxy for wholesale market prices.
+ **Average greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case).

For this study, most results focus on the snapshots of the system in 2050—the prescribed endpoint for each policy considered in this study. However, in some cases, intermediate results are also presented when relevant to the study's objectives and key messages.

2.2 Study Footprint

This report analyzes the different policy mechanisms that could be used to achieve GHG reduction goals in predominantly Washington and Oregon, with a small portion of Idaho and Montana loads that fall in BPA and AVA control areas. In this respect, the footprint of this study differs from the Northwest Regional Planning Area established by the Pacific Northwest Electric Power Planning and Conservation Act and used by regional planning entities in much of their work. This narrower study footprint representing only a portion of what is traditionally considered the Pacific Northwest is motivated by the desire to focus on the electric power sector within the states of Oregon and Washington, where policy discussions surrounding potential measures to facilitate decarbonization are considerably more advanced than elsewhere in the Pacific Northwest. Figure 2-1 shows a diagram summarizing the study footprint.

Figure 2-1. Northwest low carbon grid study footprint



This study focuses on the ratepayers of the Core Northwest region is the "Primary Zone"—the zone for which RESOLVE makes generation investment decisions. For the purposes of simulating west-wide operations, the remaining balancing authorities outside of the Core Northwest are grouped into five additional "Secondary Zones." Investments in these zones are not optimized; the trajectory of new build for the external regions is based on regional capacity needs to meet PRM targets, as well as renewable needs to comply with existing RPS policies in those regions. The detailed forecasts for buildout in other zones are covered in Appendix B.

Table 2-2. Balancing authorities included in each study region.

Category	Study Zone	Constituent Balancing Authorities
Primary Zone	Core Northwest	• Avista Corporation (AVA) • Bonneville Power Administration (BPA) • Chelan Public Utilities District (CHPD) • Douglas Public Utilities District (DOPD) • Grant County Public Utilities District (GCPD) • Pacificorp West (PACW) • Portland General Electric (PGE) • Puget Sound Energy (PSE) • Seattle City Light (SCL) • Tacoma Power (TPWR)
Secondary Zones	Other Northwest	• Idaho Power Company (IPC) • NorthWestern Energy (NWMT) • Pacificorp East (PACE) • WAPA – Upper Wyoming (WAUW)
	California	• Balancing Authority of Northern California (BANC) • California Independent System Operator (CAISO) • Imperial Irrigation District (IID) • Los Angeles Department of Water and Power (LADWP) • Turlock Irrigation District (TIDC)
	Nevada	• Nevada Power Company (NEVP) • Sierra Pacific Power (SPP)
	Rocky Mountains	• Public Service Company of Colorado (PSC) • WAPA – Colorado-Missouri (WACM)
	Southwest	• Arizona Public Service Company (APS) • El Paso Electric Co (EPE) • Public Service Company of New Mexico (PNM) • Salt River Project (SRP) • Tucson Electric Power (TEP) • WAPA – Lower Colorado
Excluded		• Alberta Electric System Operator (AESO) • British Columbia Transmission Company (BCTC) • CFE (CFE)

Alberta and British Columbia and their interactions with the rest of the Western Interconnection are not modeled in the scenarios due to lack of publicly available data. While its interactions with the Canadian provinces is an important characteristic of the Northwest electricity system, the omission of this portion of the Western Interconnection is not expected to fundamentally alter the general dynamics or overall findings of this analysis. While the availability of seasonal hydro storage in the British Columbia hydro system may provide a balancing resource that could help facilitate the operations of a low-carbon, high renewable electricity system, there is also considerable uncertainty as to the commercial arrangements that would be needed to make use of this flexibility and as to the cost that would ultimately fall upon ratepayers of the Pacific Northwest. For these reasons, the study's authors chose to focus on the dynamics of system operations within the Northwest and with its other electrical neighbors.

2.3 Scenarios & Sensitivities

2.3.1 CORE POLICY SCENARIOS

This study focuses on a suite of "Core Policy Scenarios," reflecting varied policy mechanisms that could be used to effect greenhouse gas reductions in the electric sector in the Northwest.

+ A **Reference Case** that reflects current state policies and industry trends, intended to serve as a point of comparison for alternative prospective policies;
+ A suite of **Carbon Cap Cases**, which impose limits on the total greenhouse gas emissions attributed to ratepayers in Washington and Oregon;
+ Two **Carbon Tax Cases**, which simulate the impact on the electric sector of carbon tax policies that have been proposed by the Governor and the Washington legislature; and

- A suite of **High RPS Cases**, which test the impact of broadly increasing the RPS goals established by existing statutes in the states of Washington and Oregon;
- A **No New Gas Case**, which prohibits the construction of new gas generation, forcing all future energy and capacity needs to be met by GHG-free resources.

The full set of Core Policy Scenarios included in the study is shown in Table 2-3.

Table 2-3. Full list of Core Policy Scenarios.

Category	Scenario Name	Description
Reference Case	Reference Case	Current state policy and industry trends
High RPS Cases	30% RPS	Increasingly stringent RPS targets on the region as a whole (note: current state policies would require achievement of a region-wide 20% RPS by 2040)
	40% RPS	
	50% RPS	
Carbon Cap Cases	40% GHG Reduction	Increasingly stringent carbon caps on the study footprint
	60% GHG Reduction	
	80% GHG Reduction	
Carbon Tax Cases	Governor's Tax	Two independent proposals for carbon taxes under discussion in Washington State
	Legislature's Tax	
No New Gas Case	No New Gas	Prohibition on new gas generation

The cases that compose the Core Policy Scenarios—and the key assumptions that shape each one—are described in detail below.

2.3.1.1 Reference Case

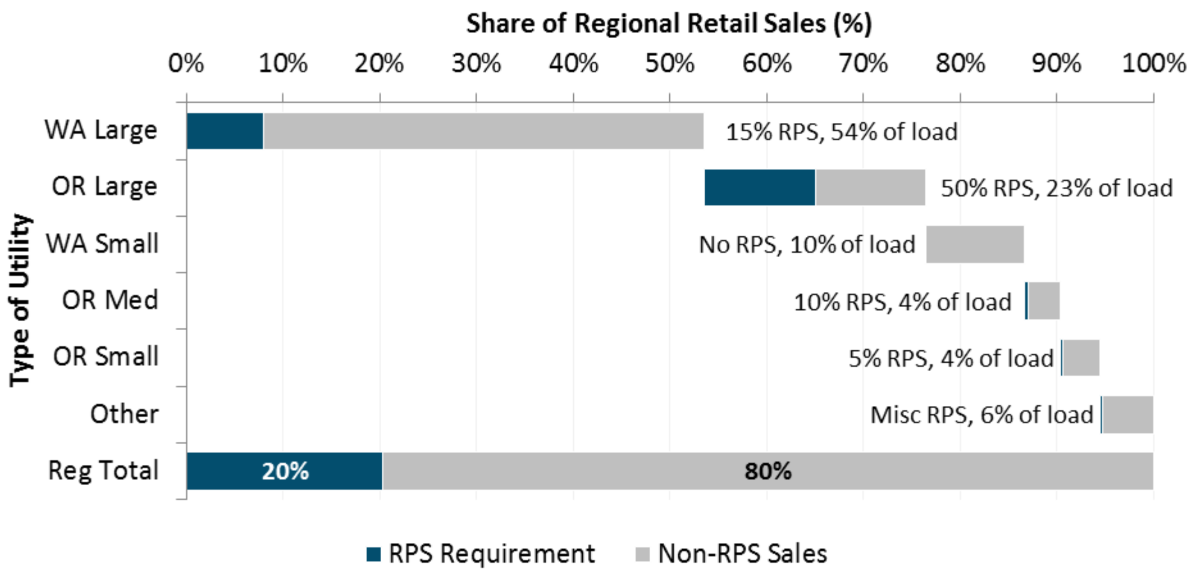
The Reference Case captures current state policies and industry trends provide a benchmark against which alternative policies may be evaluated. Key assumptions incorporated into the Reference Case include:

+ **Achievement of existing RPS goals** associated with existing statutes—including 50% for large Oregon utilities (2040), 10% for medium Oregon utilities, 5% for small Oregon utilities, and 15% for large Washington utilities (2020)—resulting in a region-wide RPS goal of 20% by 2040;
+ **Achievement of energy efficiency goals** established by the NWPCC's Seventh Power Plan;
+ **Announced retirements of coal plants** fully or partially owned by Washington and Oregon utilities, including Boardman (2020), Centralia 1 and 2 (2020 and 2024), and Colstrip 1 and 2 (2022);
+ **Forecasted cost reductions** for new solar, wind, and storage technologies consistent with industry expectations.

2.3.1.2 High RPS Cases

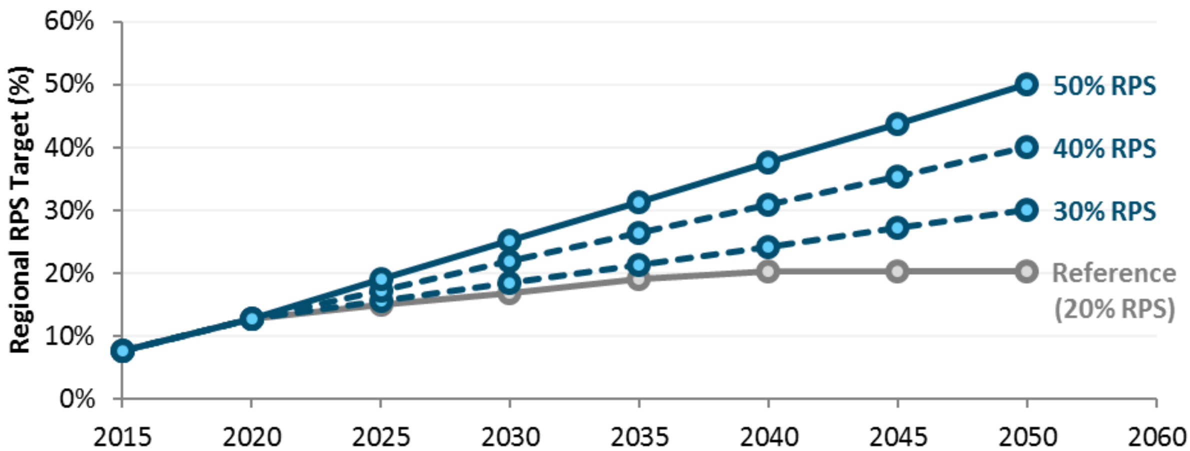
The Reference Case imposes a 20% RPS target on the combined Washington-Oregon region as a whole, a target that represents the combined impacts of the states' existing statutory policy targets. The 20% figure is derived by weighting the various targets established by each state (50% for large Oregon utilities, 10% for medium Oregon utilities, 5% for small Oregon utilities, and 15% for large Washington utilities) based on the share of regional retail sales each represents; the result is shown in Figure 2-2.

Figure 2-2. Derivation of 2040 regional RPS target for Core Northwest region



Beyond this result, this study considers three levels of increased regional RPS targets—30%, 40%, and 50%—shown in Figure 2-3. This study does not attempt to characterize the breakdown of how these regional targets might be achieved through specific policy changes applicable to specific subsegments of the electric industry; instead, it examines the overall impact of an anonymous increase to existing RPS policy across the region.

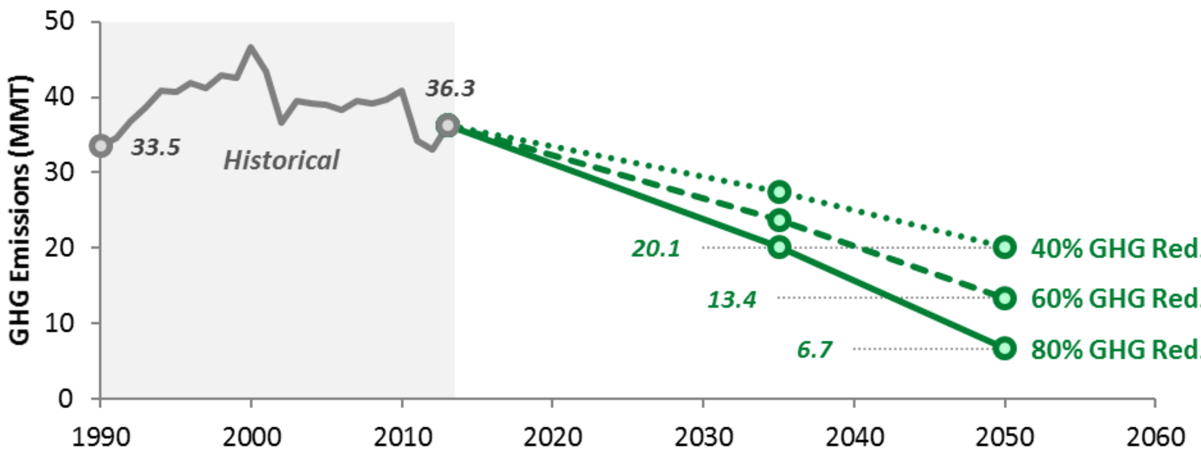
Figure 2-3. Regional RPS targets studied in Core Policy scenarios



2.3.1.3 Carbon Cap Cases

This study examines three levels of optimized greenhouse gas reduction goals in the electric sector: 40%, 60%, and 80% below 1990 levels, all achieved by 2050. The trajectories for greenhouse gas reductions in the electric sector in each of these scenarios are summarized in Figure 2-4.

Figure 2-4. Electricity sector GHG emissions targets



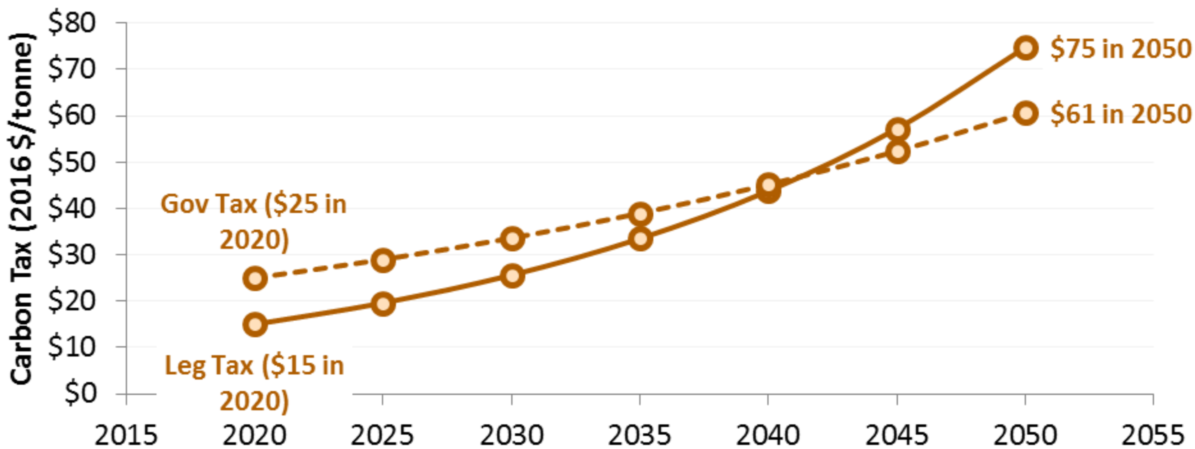
2.3.1.4 Carbon Tax Cases

This study examines two prospective trajectories for future carbon taxes, each linked to a conceptual proposal that has been discussed in Washington:

+ The Washington Governor's proposal, which introduces a carbon tax of $25/ton in 2020 that escalates at 3.5% plus inflation thereafter through 2050; and
+ A selected proposal submitted to the Washington Legislature: a carbon tax of $15/ton in 2020 escalating at 5.5% plus inflation through 2050.

The trajectories of these two carbon taxes through 2050 are shown in Figure 2-5; notably, due to the differing proposed rates of escalation, the Legislature's proposed tax reaches a higher level in 2050 ($75/ton) than the Governor's proposal ($61/ton). Since the level of carbon reductions observed is proportional to the price, the Legislature's proposed tax ultimately yields higher carbon reductions than the Governor's proposal by 2050.

Figure 2-5. Carbon tax scenarios studied



In its exploration of potential clean energy policies, this study considers both scenarios driven by a carbon cap and by a carbon tax. From the perspective of the analysis conducted in this study, these two policy mechanisms have the same impact on the electric sector. However, many other factors and considerations distinguish these two policy mechanisms from one another, and the analytical equivalence between the two in this study is not intended to imply a broader equivalence.

2.3.1.5 'No New Gas' Case

The No New Gas Case prohibits the construction of new natural gas generation within Oregon and Washington to meet future energy and capacity needs.

2.3.2 SENSITIVITY ANALYSIS

Additional sensitivity analyses are conducted to explore the impact of future uncertainties on the cost of greenhouse gas reduction in the Northwest. These sensitivities reflect uncertainties that are outside the control of electric utilities in the Northwest area but may have an impact on the cost to the region to meet decarbonization goals. The full list of sensitivities explored within this analysis is shown in Table 2-4.

Table 2-4. Inventory of sensitivities explored in analysis.

Sensitivity	Description
No Revenue Recycling	Examine impact to ratepayers if revenue collected under carbon pricing mechanism is not returned to the electricity sector
Loss of Existing Carbon Free Resource	Examine the cost and GHG implications of decommissioning existing hydro and nuclear generation
High EE Potential	Examine the potential role of higher-cost energy efficiency measures in a GHG-constrained future
High Electric Vehicle Adoption	Explore the role of vehicle as a potential strategy for reducing GHG emissions in the transportation sector
High and Low Gas Prices	Examine sensitivity of key learnings to assumptions on future natural gas prices
Low Technology Costs	Explore changes in cost and portfolio composition under assumptions of lower costs for solar, wind and energy storage
California 100% RPS	Explore implications of California clean energy policy on decarbonization in the Northwest

3 Inputs and Assumptions

3.1 Load Forecast

3.1.1 RETAIL SALES

The regional load forecast used in this study captures expected future changes in electricity demand within the Core Northwest region. The load forecast comprises four components:

+ **Baseline consumption:** a counterfactual forecast of demand meant to capture future economic and demographic trends, prior to considering the impacts of transportation electrification, energy efficiency, and behind-the-meter PV;
+ **Transportation electrification:** new electric system loads resulting from the adoption and subsequent charging of electric vehicles (EVs);
+ **Energy efficiency:** load reduction achieved through future utility conservation programs encouraging customer adoption of efficient technologies and devices; and
+ **Behind-the-meter PV:** load reduction due to customer adoption of behind-the-meter solar PV generation, predominantly under net energy metering tariffs.[17]

This study's assumptions for each of these components of the load forecast are discussed below. Table 3-1 shows this study's assumptions for each of these components of the demand forecast.

[17] While shown here as a load modifier, behind-the-meter PV is modeled as a supply-side resource in RESOLVE. Thus, while it has the effect of reducing retail sales, its impact on operations due to its hourly profile is captured explicitly.

Table 3-1. Components of Core Northwest load forecast.

	Hist (aMW)		Forecast (aMW)			CAGR (%/yr)
Category	**2015**	**2020**	**2030**	**2040**	**2050**	**(2015-'50)**
Baseline Consumption	**16,606**	**17,714**	**20,157**	**22,936**	**24,466**	**1.3%**
Trans Electrification	+14	+79	+303	+449	+592	
Energy Efficiency	—	-729	-2,186	-3,643	-5,100	
Behind-the-Meter PV	-22	-38	-69	-101	-133	
Final Retail Sales	**16,598**	**17,027**	**18,205**	**19,641**	**21,457**	**0.7%**

Note that retail sales are grossed up for transmission and distribution losses (6%) when simulating the operations of the bulk electric power system. Assumptions for each of the load modifiers are derived from NWPCC's Seventh Power Plan; the derivation of these assumptions is further described in Appendix B.

The load forecasts and implied load growth rates before and after the impact of embedded energy efficiency are benchmarked against a variety of other load forecasts for the Northwest, including the NWPCC *Seventh Power Plan*, BPA *2016 White Book*, TEPPC 2026 Common Case, and the PNUCC *Northwest Regional Forecast* to ensure that the expected increases in loads are within reasonable bounds.[18] Because most studies within the region explicitly consider the anticipated load impact of energy efficiency, anticipated growth rates are benchmarked both prior to and after considering the load impact of energy efficiency. The comparison of the pre- and post-EE load growth rate used in this study to the different sources surveyed is shown in Table 3-2.

[18] Note that each study referenced here has slightly different definitions for how energy efficiency is included (or not included) in the demand forecast. The categorization shown in this table reflects the best judgements of this study's authors as to the most consistent comparisons across studies.

Table 3-2. Benchmarking of load growth assumptions to other Northwest regional planning studies

Study	Period	Pre-EE CAGR	Post-EE CAGR
NWPCC Seventh Power Plan	2015-2035	0.9%	0.0%
BPA White Book	2016-2026	1.1%	—
TEPPC 2026 Common Case	2016-2026	—	1.3%
PNUCC Load and Resources Assessment	2018-2027	1.7%	0.9%
E3 PNW Low Carbon Scenario Analysis	**2015-2050**	**1.3%**	**0.7%**

3.1.2 PEAK DEMAND

Forecasts of peak demand are similarly built up based on the assumed components of the demand forecast and are evaluated based on an assumed load factor. The demand at the customer meter is further grossed up for assumed transmission and distribution losses to provide the estimates regional peak demand. The load factor applied to each component of the demand forecast varies:

+ **Baseline consumption** is modeled with a load factor of 65%, derived from regional hourly load data from 2015.
+ **Transportation electrification:** the load impact on peak is split up to account for managed and unmanaged charging. Managed charging (assumed to be 60% of EV load) reflects a "smart charging" profile that is generally not coincident with system peak and has a high load factor (5.71). Unmanaged charging results is assumed to have a low load factor (0.43) and has a much larger impact on peak demand.
+ **Energy efficiency** is assumed to have the same load factor as baseline consumption (65%).
+ **Behind-the-meter PV** is not explicitly accounted for in the peak demand forecast because it is treated as a supply-side resource within RESOLVE. As such, its contribution to meeting peak needs (which is small, as the winter evening peak coincides with periods of little to no solar production) is evaluated as part of the overall contribution of variable renewables towards resource adequacy needs. See Section 3.4.4.

The component buildup of regional peak demand is shown in Table 3-3.

Table 3-3. Components of Core Northwest peak demand forecast

	Hist (MW)		Forecast (MW)			CAGR (%/yr)
Category	2015	2020	2030	2040	2050	(2015-’50)
Baseline Peak	**27,338**	**29,162**	**33,183**	**37,758**	**42,963**	**1.3%**
Trans Electrification	+32	+151	+315	+468	+542	
Energy Efficiency	—	-1,199	-3,598	-5,997	-8,396	
Regional Peak Demand	**27,370**	**28,113**	**29,899**	**32,228**	**35,183**	**0.7%**

3.1.3 HOURLY PROFILES

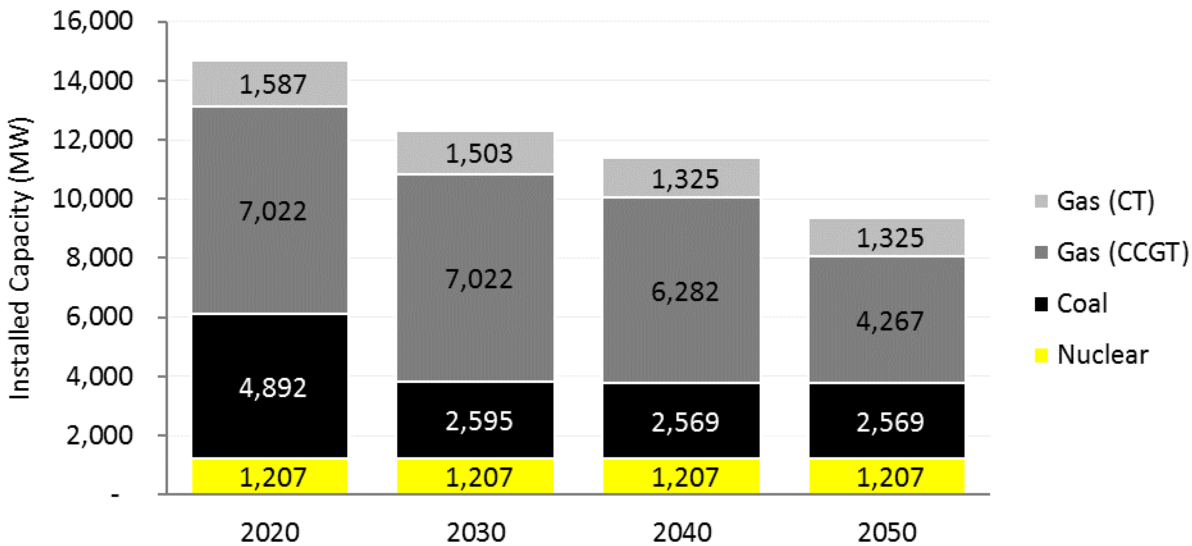
Load profiles for the 41 representative days modeled in RESOLVE are sampled from the 2007-2009 period and reflect actual hourly regional loads (scaled to future levels of demand).

3.2 Thermal Generation

3.2.1 EXISTING RESOURCES

The primary source for data on existing and planned generation is the Western Electricity Coordinating Council’s (WECC) 2026 Common Case, developed and maintained by the Transmission Expansion Planning Policy Committee (TEPPC). The composition of the Core Northwest thermal fleet, accounting for the impacts of planned plant retirements, is shown in Figure 3-1.

Figure 3-1. Installed capacity of existing thermal resources in the Core Northwest portfolio over time



3.2.1.1 Nuclear

Columbia Generating Station (CGS) is assumed to remain online throughout the analysis period. The capacity of CGS is modeled at 1,207 MW, reflecting an uprated capacity to account for recent plant upgrades.

3.2.1.2 Coal

The portfolio of coal resources attributed to the Core Northwest region includes both coal resources geographically located within the footprint as well as shares of remote resources owned by utilities in the Core Northwest.[19] In general, this study takes the approach of assuming that existing coal plants will remain in service throughout the analysis unless the plant or its owning utility has formally declared an

[19] Coal plants owned by Pacificorp are assumed to be split between Pacificorp West (within the Core Northwest footprint) and Pacificorp East (outside the footprint) according to load ratio share (32%/68%, respectively).

intention to retire the plant. The coal plants in the Core Northwest portfolio that are assumed to retire according to this criterion include **Boardman** (2020), **Centralia 1 and 2** (2020 and 2024, respectively), and **Colstrip 1 and 2** (2022).[20] While some utility integrated resource plans have analyzed potential additional coal plant retirements, this study takes a conservative approach from the greenhouse gas perspective to assume these plants remain in service until there is a formal retirement announcement, allowing this study to examine explicitly the implications of continuing to operate remaining coal plants. The full list of coal plants included in the Core Northwest portfolio is shown in Appendix B.

3.2.1.3 Natural Gas

The portfolio of gas generators included in the Core Northwest includes all gas generators within the geographic footprint, including both merchant plants and those owned by utilities. Existing gas plants were generally assumed to remain in service through 2050; however, a subset of existing plants was identified by PGP members as likely candidates for retirement. These plants are assumed to retire at the end of their economic lifetimes (but are available for "repowering" in the portfolio optimization if they are needed for long-term energy and capacity needs). The full list of gas plants included in the region is shown in Appendix B.

3.2.2 NEW RESOURCE OPTIONS

Several different options for new thermal generation resources are considered in RESOLVE's portfolio optimization, including combined cycles (CCGTs), combustion turbines (CTs), and reciprocating engines. The natural gas resource classes available to the model and their respective all-in fixed costs, are derived from E3's 2017 review of capital costs for WECC, *Review of Capital Costs for Generation Technologies*.[21]

[20] This study also assumes that North Valmy 1 and 2 are retired (2022 and 2026, respectively); however, as these units are owned by entities outside the Core Northwest (Idaho Power and NV Energy), they are not included in the Core Northwest footprint.
[21] Available at: **https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf**

The all-in fixed cost metric used by RESOLVE incorporates all capital, financing, and fixed O&M costs, but excludes the cost to operate the plant—variable costs are evaluated separately through the dispatch optimization. The different cost components for candidate conventional resources are shown in Table 3-4 below.

Table 3-4. Fixed cost assumptions for new gas resources

New Resource Option	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	All-In Fixed Cost ($/kW-yr)
Gas (CT)	$950	$6	$150
Gas (CCGT)	$1,300	$10	$202
Gas (ICE)	$1,250	$12	$197

In addition to investments in new natural gas resources, the ability to repower existing CCGTs at the end of their economic lifetime is also considered as an option. The cost of repowering an existing CCGT is assumed to be 75% the cost of building a new greenfield CCGT—this is meant to capture the likely need for major new investments in new equipment and infrastructure at the time of repowering. By 2050, 2,500 MW of existing CCGTs are assumed to have reached the end of their economic lifetimes and are available for repowering.

3.2.3 OPERATIONAL PARAMETERS

The operational characteristics for the fleet determine the dispatch decisions for the different resources in RESOLVE. The different operational parameters are derived from the CPUC IRP RESOLVE model and TEPPC generator database characteristics. Nuclear generation is treated as must-run, but all other thermal resources are dispatched economically.

Peakers have higher start-up costs and ramping abilities, whereas combined cycle units have lower costs and ramping abilities, but higher minimum capacity (Pmin) requirements. Variable O&M costs of $5/MWh

- \$6/MWh are used for gas plants depending on their characteristics and location. RESOLVE determines dispatch decisions by considering tradeoffs between various attributes of thermal resources including start-up costs, minimum up and down times, heat rates at different operating levels, and percent of nameplate capacity that is the minimum capacity for the generator to be operated at once it's committed and turned on. Table 3-5 shows the operational characteristics for the thermal generators in the Core Northwest.

Table 3-5. Operational characteristics for resource categories modeled in the Core Northwest

Resource Type	Technology	Pmin (%)	Max Ramp Up (%Pmax/hr)	Heat Rate at Pmax (Btu/kWh)	Heat Rate at Pmin (Btu/kWh)	Min. up/ downtime (hrs)	VOM (\$/MWh)
Existing Resources	Nuclear	100%	20%	11	11	24	\$6
	Coal	42%	66%	11	11	24	\$5
	Gas (CCGT)	53%	57%	7	8	6	\$6
	Gas (CT)	36%	322%	11	13	1	\$5
New Resource Options	Gas (CCGT)	53%	57%	7	8	6	\$6
	Gas (CT)	36%	322%	11	13	1	\$5
	Gas (ICE)	36%	322%	11	13	1	\$5

3.2.4 RESOURCE ADEQUACY CONTRIBUTION

For the thermal fleet, the contribution of resources to meeting the region's planning reserve margin need is assumed to be 100% of nameplate capacity, i.e., the full capacity of the resources can count 1-for-1 in meeting the resource adequacy needs of the Core Northwest region.

3.3 Hydroelectric Generation

Approximately 31,500 MW of hydroelectric generating capability—capable of producing roughly 14,000 aMW of generation during average water conditions—is located within the Core Northwest study footprint. This study assumes that this fleet of hydroelectric generators remains unchanged over the horizon of this analysis through 2050.

3.3.1 OPERATIONAL PARAMETERS

The operational capabilities of the existing Northwest hydroelectric fleet are characterized by several constraints in RESOLVE:

+ **Daily energy limits** on the amount of hydro generation that is available in each of the 41 days modeled in RESOLVE;
+ **Daily minimum and maximum capacity limits** that set bounds on the lower and upper amount that the hydro fleet can generate in any hour;
+ **Multi-hour ramping limits** that constrain the rate at which the hydro system, in aggregate, can change its level of output.

Each of these constraints are applied to the aggregate hydro fleet of the Core Northwest region, recognizing that large parts of the fleet—particularly the federal hydro system—do operate as an integrated system. These constraints, then, are meant not only to capture the physical capabilities of individual generation facilities, but limits on the aggregate system to respond to wholesale market signals considering both physical and institutional factors. These constraints are developed based on two key data sets:

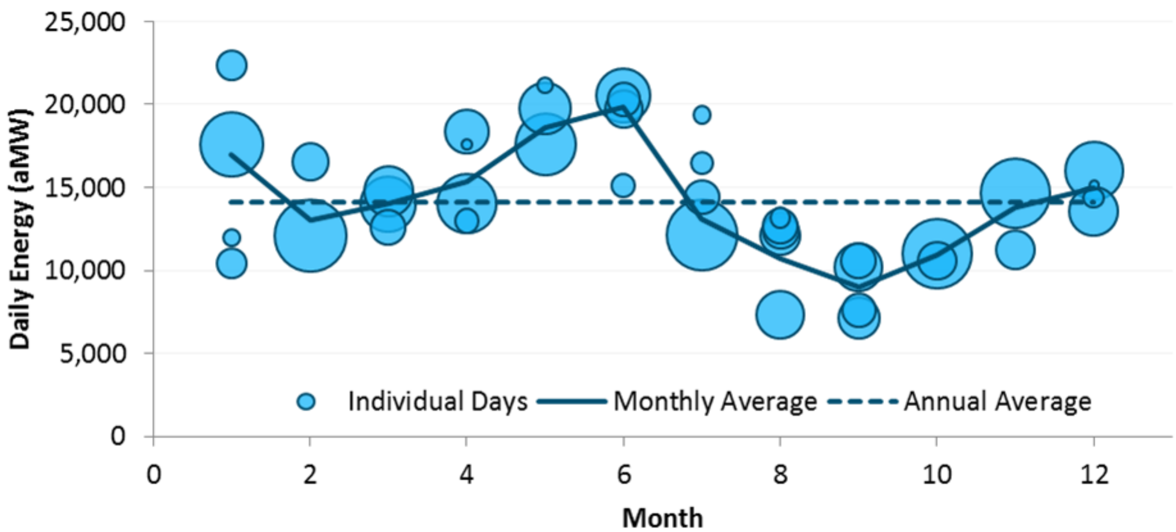
+ **BPA HYDSIM simulated monthly hydro output (1929-2008):** using its HYDSIM model, BPA has simulated the output of the current regional hydro system under hydrological conditions spanning an eighty-year period. This data set serves to establish the full distribution of potential levels of hydro output—as well as associated probabilities—that the Northwest hydro system may be capable of producing.

+ **Actual hourly hydro output (2001, 2005, 2011):** hourly operations of individual hydro plants in the Northwest for three years representing a range of hydro conditions (dry, normal, and wet) were obtained from WECC. This data is used for multiple purposes, including the extrapolation of simulated monthly budgets to daily budgets as well as in the development of operating constraints applied to hydro within each day.

3.3.1.1 Daily Energy Limits

The daily energy budgets modeled in RESOLVE are an output of the day selection algorithm used to select a representative subset of days for modeling within the capacity expansion process (see Appendix A). As daily hydro budgets are included as one of the criteria in the day sampling process, the daily hydro budgets span the full distribution of potential conditions on the hydro system. The daily and seasonal patterns of hydro energy are shown in Figure 3-2.

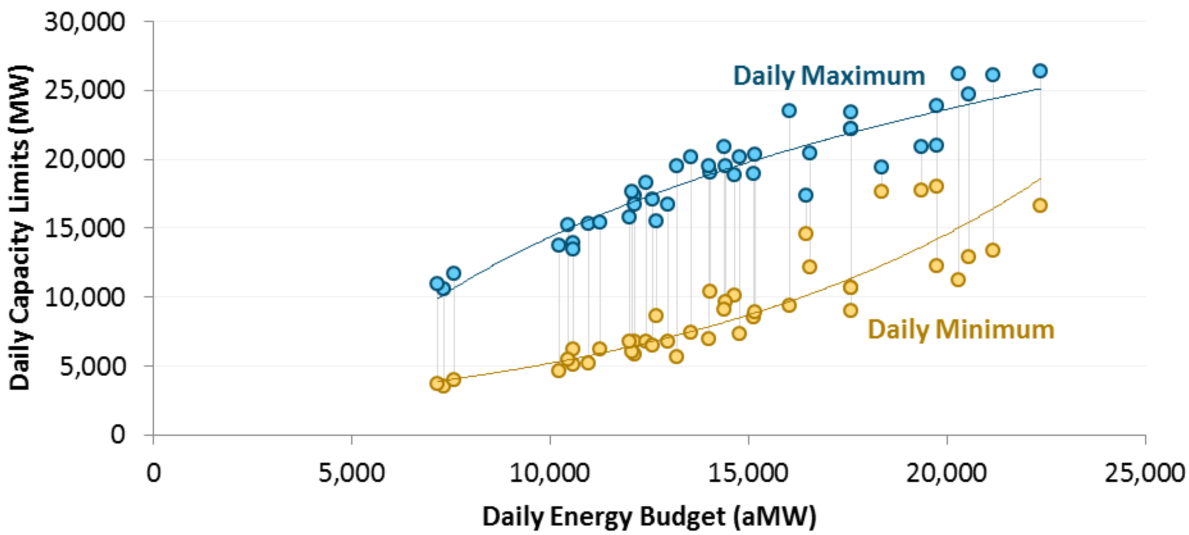
Figure 3-2. Hydro budgets for each of the 41 days modeled within RESOLVE



3.3.1.2 Capacity Limits

For each operational day that is modeled, the aggregate hydro fleet of the Northwest is also limited to a minimum and maximum capacity output in each hour. The daily capacity limits are based on actual hydro operations observed in the three years for which hourly data is available. Each day included in the sample modeled in RESOLVE is based on an actual operating day from one of these years; the minimum and maximum capacity constraints are based on the observed hourly minimum and maximum output of the hydro fleet on that day. These daily minima and maxima are shown as a function of the daily energy budget for each of the operating days modeled in RESOLVE in Figure 3-3.

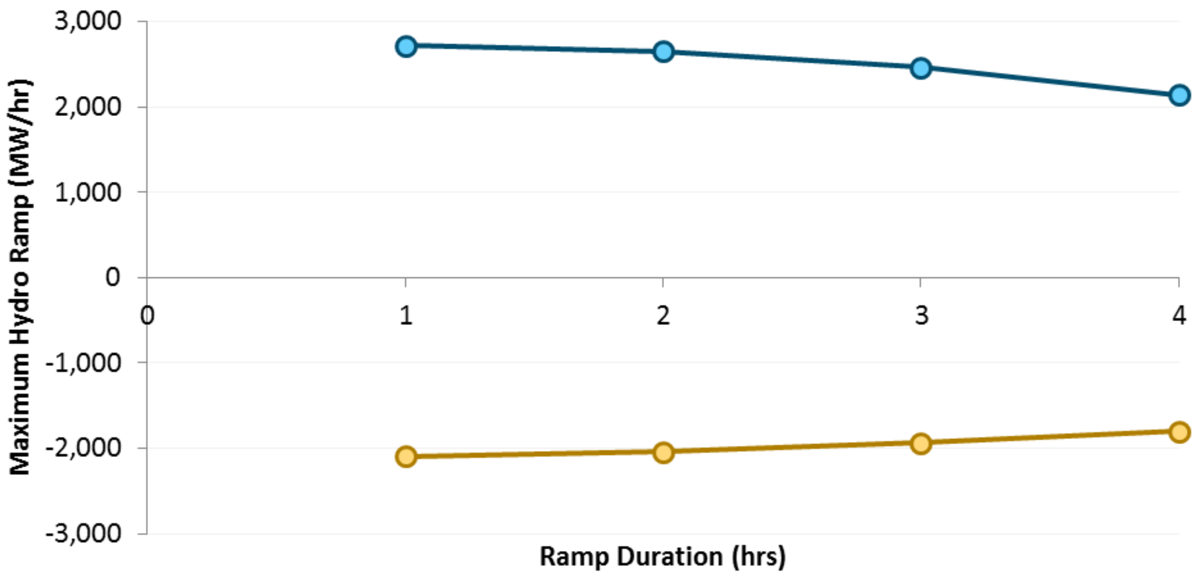
Figure 3-3. Minimum and maximum capacity constraints as a function of daily energy budget



3.3.1.3 Ramping Limits

The capability of the hydro fleet to adjust its output from one hour to the next (as well as across periods of up to four hours) is also constrained in the simulation based on actual observed historical ramping patterns. This type of constraint is intended to capture the complete set of physical and institutional factors (e.g. cascading hydro and streamflow constraints; navigation, irrigation, and flood control) that limit the amount of flexibility in the hydro system. Upward and downward ramping constraints for periods from one to four hours are therefore derived from actual historical operating data, based on the 99th percentile of upward and downward ramps observed across the three available years of hourly data (2001, 2005, and 2011). These constraints are shown in Figure 3-4.

Figure 3-4. Multihour ramping constraints applied to Northwest hydro



3.3.2 RESOURCE ADEQUACY CONTRIBUTION

This study adopts the conventions used by the PNUCC in its *Northwest Regional Forecast*,[22] which assumes that the firm capacity contribution of hydro is 66% of its nameplate capacity, based on its 10-hour sustained peaking capability under critical hydro conditions. For the total hydro fleet in the Core Northwest region, the 31,500 MW hydro system contributes 20,800 MW of capacity to the region's planning reserve margin.

[22] Available at: http://www.pnucc.org/sites/default/files/file-uploads/2017%20PNUCC%20NRF.pdf

3.4 Renewable Generation

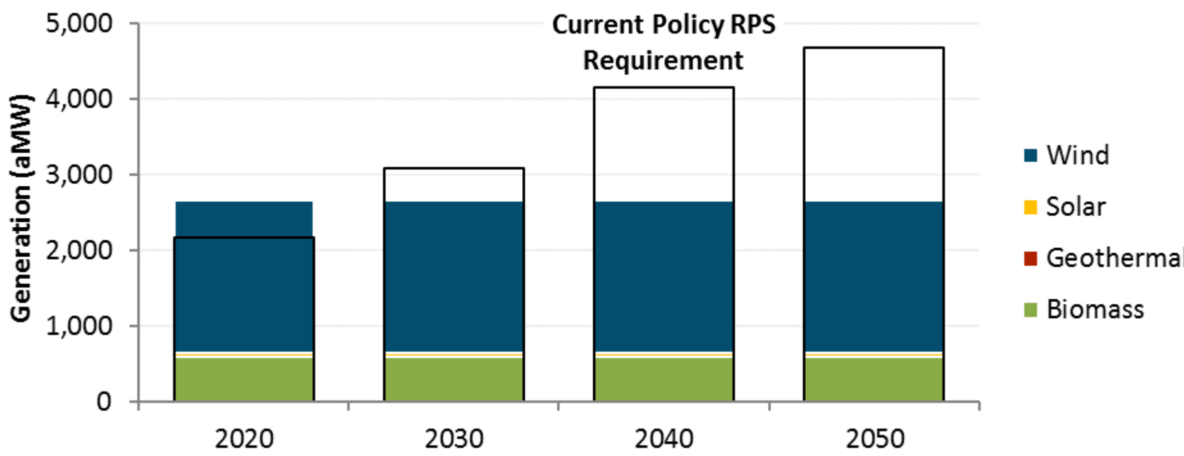
3.4.1 EXISTING RESOURCES

The study assumes that all the existing renewable resources remain online through the end of the modeling horizon. Data from the TEPPC 2026 Common Case is used to determine the capacity of the existing renewable fleet by resource type, as well as expected near-term additions. The generation and capacity data from the TEPPC database is also used to derive annual capacity factors for wind and solar resources in the region. The existing renewable resources attributed to the Core Northwest are further refined through benchmarking against EIA historical generation, which was used to adjust the output of the biomass plants in the region to levels consistent with actual historical output.

Resources physically located in the Core NW region but contracted to California are modeled in California, and do not count towards policy needs in the Core NW. Similarly, renewables contracted to the Core NW are modeled in the main zone instead of the region they are physically located in.

Current level of renewables is at approximately 2000 aMW, and in combination with planned near term additions of approximately 400 aMW, are sufficient to meet RPS policy needs through 2020. By 2030, the incremental renewables capacity needed is roughly 640 aMW, which increases to almost 2000 aMW by 2050.

Figure 3-5. Existing and planned renewables resources in the Core Northwest region relative to current RPS policy goals



3.4.2 NEW RESOURCE OPTIONS

A variety of new resources, including potential investments in wind, solar, geothermal, and hydro upgrades, are considered as options for future renewable investments. The supply curve for renewables included in this builds upon the menu of renewable resource options considered in the NWPCC Seventh Power Plan, with updates to capture technological evolution and with additional resources to augment the available pool of resources. To capture the most recent reported costs for renewable technologies, this study relies on E3's 2017 review of capital costs for WECC, *Review of Capital Costs for Generation Technologies*[23] as the primary source of cost assumptions for new renewables. The resulting supply curve is a technologically and geographically diverse set of resources that may be selected in each scenario.

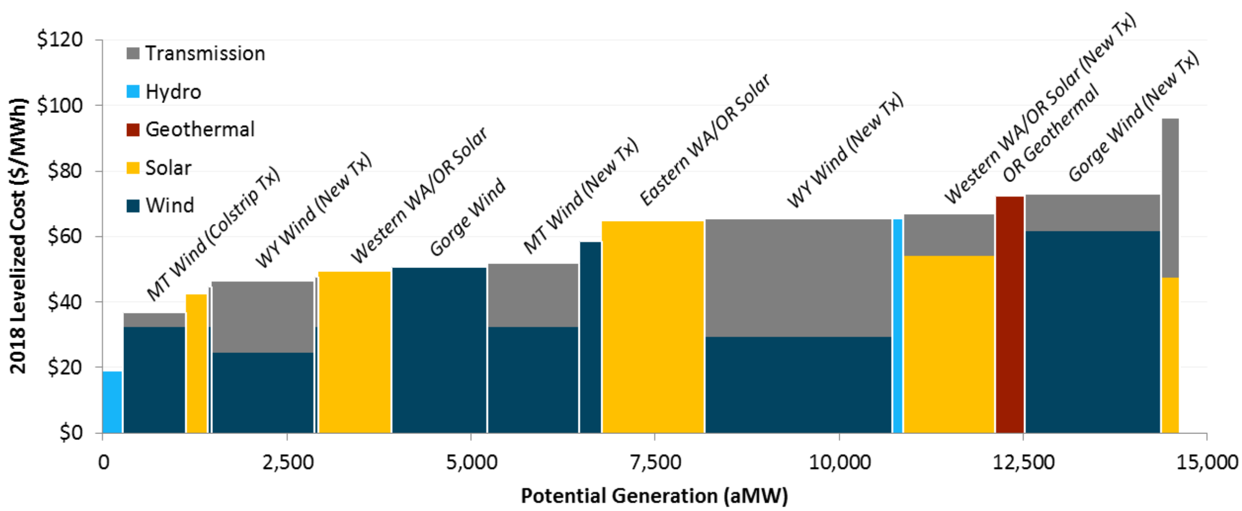
The supply curve for renewables comprises three primary pieces of information:

[23] Available at: https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf

+ **Levelized cost of energy,** calculated based on assumed capital, fixed O&M, and operational costs, anticipated resource-specific capacity factors, and detailed project financing assumptions;
+ **Transmission adder[24],** if applicable, derived from a variety of different sources;
+ **Resource potential,** reflecting the assumed limits on feasible developable potential for the purposes of this study.

The supply curve of resources considered in this study—shown at their present-day levelized costs—is shown in Figure 3-6.

Figure 3-6. Supply curve of potential new renewable resources.



While Figure 3-6 shows a snapshot of present-day cost—reflecting current technology costs, financing assumptions, and tax credits, the costs of developing new renewable generation changes through time—

[24] The transmission adder captures both the cost of incremental investments in new transmission and the cost of wheeling on existing systems paid to transmission owners outside of the Pacific Northwest. It does not include wheeling costs paid to transmission owners (e.g. BPA) within the Core Northwest for use of the existing transmission system, as these costs are sunk and are not treated as incremental costs to ratepayers within the region.

particularly due to anticipated technology cost reductions as well as the expiration of federal tax credits in the early 2020s. This analysis captures both of these effects, as the levelized cost of renewable investments made in each period reflects the capital costs and available tax credits at that time. For solar resources, capital costs are assumed to decline by 12% in real terms relative to present-day costs by 2030, and are held constant thereafter. Assumed cost declines for wind resources are lower due to the relative maturation of wind technology; costs are assumed to decline 3% in real terms by 2030.

Table 3-6 summarizes the characteristics of all the new resource options considered in the study for renewable resources. Additional detail on the specific resources included and data sources used to develop this supply curve are included in Appendix B.

Table 3-6. New renewable resources considered to meet policy goals in the Core Northwest

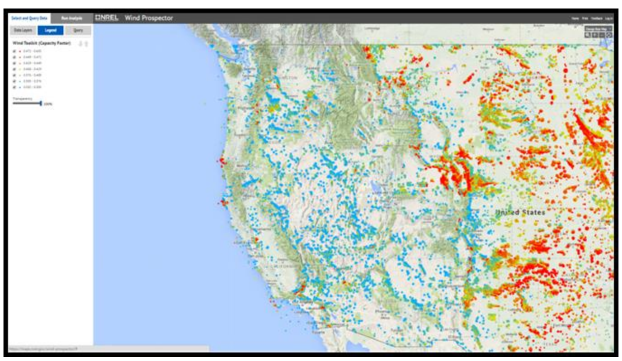
Technology	Resource		Potential (MW)	Capacity Factor (%)	Capital Costs ($/kW) 2018	Capital Costs ($/kW) 2030	2018 Levelized Cost ($/MWh) Energy	2018 Levelized Cost ($/MWh) Trans	2018 Levelized Cost ($/MWh) All-in	2030 Levelized Cost ($/MWh) Energy	2030 Levelized Cost ($/MWh) Trans	2030 Levelized Cost ($/MWh) All-in
Hydro	**Non-Powered Dams**		388	20%	$4,500	$4,500	$65	—	$65	$65	—	$65
	Upgrades		211	66%	$1,350	$1,350	$19	—	$19	$17	—	$17
Geothermal	**Central Oregon**		450	90%	$4,557	$4,557	$72	—	$72	$72	—	$72
Solar PV*	**Southern Oregon**		1,000	29%	$1,617	$1,438	$43	—	$43	$57	—	$57
	Eastern WA/OR	1	4,000	25%	$1,617	$1,438	$49	—	$49	$67	—	$67
		2	5,000	25%	$1,617	$1,438	$49	$13	$62	$67	$13	$79
	Western WA/OR		7,680	19%	$1,617	$1,438	$65	—	$65	$88	—	$88
	Southern Idaho		989	26%	$1,617	$1,438	$47	$49	$96	$64	$49	$113
Wind	**Columbia River**	1	4,000	32%	$1,924	$1,882	$55	—	$55	$77	—	$77
		2	6,500	28%	$1,924	$1,882	$66	$11	$77	$85	$11	$97
	Montana	1	2,000	42%	$1,823	$1,783	$32	$4	$37	$54	$4	$58
		2	100	42%	$1,823	$1,783	$32	$12	$45	$54	$12	$66
		3	200	42%	$1,823	$1,783	$32	$15	$48	$54	$15	$69
		4	3,000	42%	$1,823	$1,783	$32	$19	$52	$54	$19	$73
	Steens Mtn		977	29%	$1,823	$1,783	$58	—	$58	$78	—	$78
	Wyoming	1	3,000	46%	$1,722	$1,684	$25	$22	$46	$47	$22	$69
		2	6,000	42%	$1,722	$1,684	$29	$36	$65	$51	$36	$87

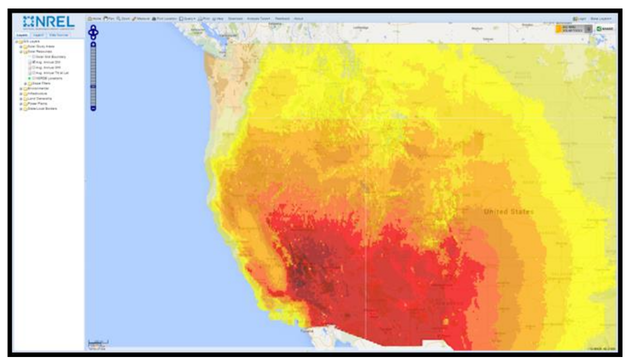
** Solar PV plants modeled in this study are assumed to be single-axis tracking plants with an inverter loading ratio of 1.3. All costs for solar PV (e.g. capital cost, $/kW) are reported on an AC-nameplate basis.*

3.4.3 HOURLY PROFILES

Hourly profiles for wind and solar generation throughout the Western Interconnection are derived from the National Renewable Energy Laboratory's (NREL) WIND Toolkit and Solar Prospector, respectively (see Figure 3-7). The WIND Toolkit provides simulated output for a large number of selected sites throughout the western United States derived using a mesoscale weather model. The Solar Prospector provides historical hourly irradiance data, which is used to simulate the output of hypothetical solar PV plants throughout the west. Both wind and solar profiles used in this study are scaled to match anticipated regional capacity factors.

Figure 3-7. Screenshots from NREL's Wind Prospector (left) and Solar Prospector (right)





The hourly profiles modeled in RESOLVE reflect the conditions on the 41 days sampled to represent composite distributions for load, wind, solar, and hydro. These hourly profiles are sampled from the 2007-2009 period.

3.4.4 RESOURCE ADEQUACY CONTRIBUTION

The contribution of renewable generation resources towards resource adequacy needs varies by resource type. For the purposes of calculating the regional planning reserve margin, renewables are further subdivided into two categories: baseload resources (biomass, geothermal, and hydro upgrades) and variable resources (wind and solar PV).

The contribution of baseload resources towards the planning reserve margin is simply assumed to be equal to their average capacity factor. That is, a 100 MW biomass plant that operates at 80 aMW throughout the year is assumed to contribute 80 MW towards the regional planning reserve margin requirement.

The contribution of wind and solar resources, whose hourly variability results in lower capacity value, is evaluated dynamically within RESOLVE based on the concept of **"effective load carrying capability" (ELCC)**. While not unique to variable renewable resources, the concept of ELCC is most widely used to quantify the capacity contribution of a variable resource whose availability changes on an hourly basis; it represents the amount of traditional baseload capacity that would need to be added to the system in order to achieve the same level of reliability as the variable resource provides. Integrating ELCC into a capacity expansion model like RESOLVE poses an interesting challenge because (1) computing renewables ELCC typically requires the use of loss-of-load probability modeling and is too computationally intensive to integrate into long-term optimization; (2) the marginal ELCC of a renewable resource depends not only on the characteristics of that resource, but on the composition of the whole portfolio of existing variable renewables; and (3) the relationships between renewables and ELCC at increasing penetration are typically nonlinear.

In order to incorporate the ELCC logic into RESOLVE, this study relies on prior loss-of-load-probability analysis to characterize ELCCs for a wide range of potential renewable portfolios in the Northwest in E3's *Western Interconnection Flexibility Assessment*.[25] In this study, E3 used RECAP—a LOLP model—to evaluate the ELCC provided by a range of different portfolios of wind and solar resources in the Northwest.

[25] Available at: **https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf**

The “surface” traced out in E3’s prior work has been parameterized for use in RESOLVE, such that RESOLVE calculates the ELCC for the combined portfolio of variable resources as a function of load, wind penetration, and solar PV penetration.

3.5 Energy Storage

3.5.1 NEW RESOURCE OPTIONS

RESOLVE considers three types of energy storage to meet capacity and balancing needs in its optimization: (1) lithium ion batteries, (2) flow batteries, and (3) pumped storage. Costs for new energy storage are broken down into power costs and energy costs. The power cost refers to all costs that scale with the rated installed power (kW) while the energy costs refers to all costs that scale with the duration/energy of the storage resource (kWh).[26] This approach allows RESOLVE to optimize the sizing of energy storage capacity and duration independently, providing an indication of what duration of energy storage provides the most value to the region.

The cost assumptions for new pumped storage resources are based on Lazard’s *Levelized Cost of Storage 2.0*.[27] Because of its relative technological maturity compared to emerging technologies considered in this study, pumped storage costs are assumed to remain constant in real terms. New pumped storage potential within the region is limited to 5,000 MW. This reflects roughly two times the total capacity of projects currently at some phase of commercial development within the region.

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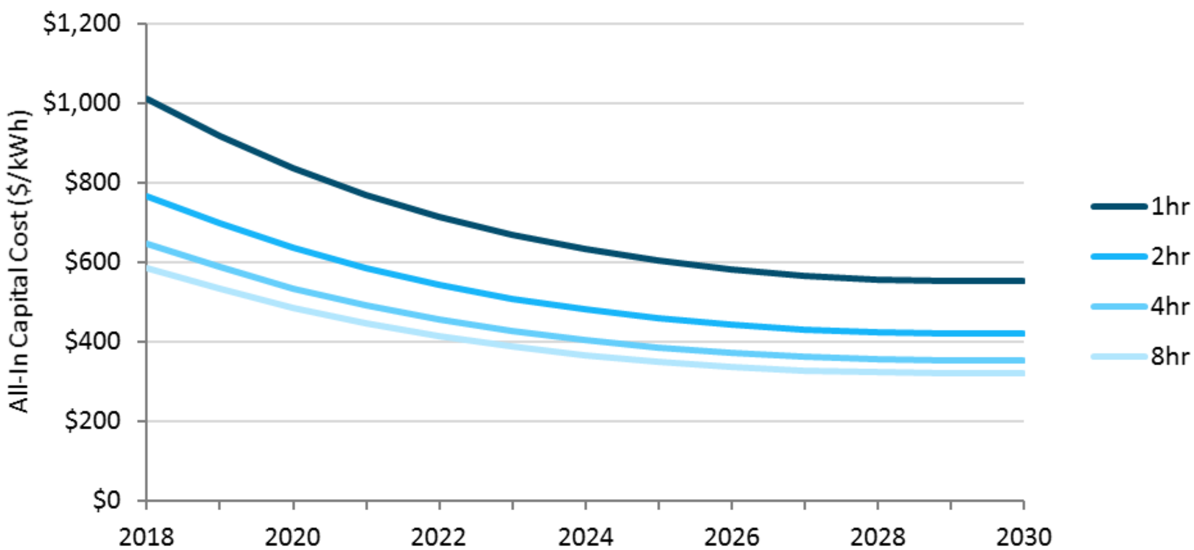
[26] For example, for pumped storage, power costs relate to the costs of the turbines, the penstocks, the interconnection, etc., while energy costs are small and mainly cover the costs of digging a reservoir; for li-ion batteries, the power costs mainly relate to the cost of an inverter and other power electronics, while the energy costs relate to the actual battery cells.

[27] Available at: **https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-20/**. E3 used the average of the range provided in p. 31 of the Appendix. For the breakout of power to energy cost, E3 used the specified duration (8-hours) and assumed energy costs per kWh are 1/10th of the power costs per kW.

Estimates of current and future battery costs are derived from a review of multiple studies and projections of battery costs, primarily Lazard's *Levelized Cost of Storage 2.0*[28] (2016) and DNV GL's *Battery Energy Storage Study for the 2017 IRP*[29] (commissioned by Pacificorp in 2016). Costs for new energy storage technologies are assumed to decline through 2030 the technologies mature. Cost projections for lithium ion batteries—currently the least-cost and most mature battery technology available on the market—are shown in Figure 3-8.

Figure 3-8. Capital cost assumptions for lithium-ion batteries as a function of duration through 2030



Detailed cost assumptions for new energy storage resources are included in Appendix B.

[28] Available at: https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

[29] Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf

3.5.2 RESOURCE ADEQUACY CONTRIBUTION

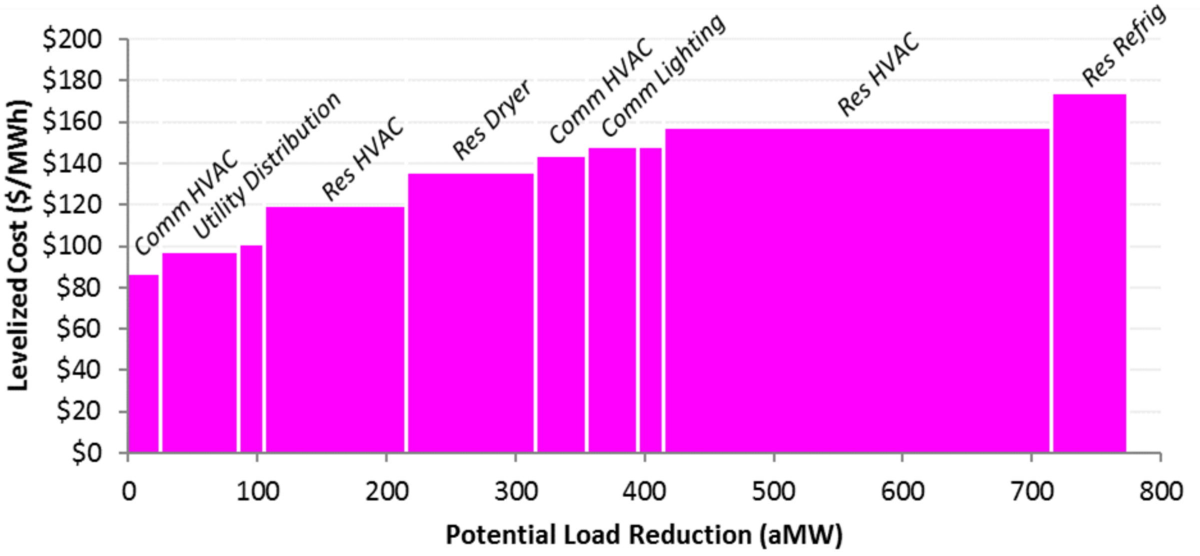
The contribution of new storage resources to resource adequacy needs within the region assumes that a storage resource must have ten hours of duration to receive a capacity credit equal to its nameplate capacity; for shorter duration energy storage resources, the capacity credit scales linearly with duration. This relatively stringent requirement for longer-duration batteries to meet the resource adequacy needs of the region is based on the premise that the existing generation fleet in the Northwest—heavily reliant on energy-limited hydro resources—will be constrained not only by its ability to meet a single hour peak but to deliver energy over a longer sustained period. The ten-hour duration requirement for energy storage mirrors the use of the ten-hour sustained peaking capability under critical water conditions to measure the contribution of the region's hydro fleet towards its planning reserve margin.

3.6 Additional Demand-Side Resources

3.6.1 INCREMENTAL ENERGY EFFICIENCY

In addition to the embedded cost-effective energy efficiency (EE), the model is allowed to optimize new EE build to reduce RPS need, or as a way to reduce GHG gas emissions by reducing loads that need to be met with carbon free resources. The data for capacity, potential, impacts shapes, and costs for incremental energy efficiency developed by NWPCC for the Seventh Power Plan was used to characterize incremental energy efficiency resources. Measures from the Seventh Power Plan supply curve were grouped into categories according to cost and end use, including measures in the following end uses: (1) commercial HVAC, (2) commercial lighting, (3) residential HVAC), (4) residential dryer, (4) residential refrigeration, (5) industrial lighting, and (6) utility distribution. The supply curve used in this study is shown in Figure 3-9.

Figure 3-9. Supply curve of incremental efficiency measures included in optimization



3.6.2 DEMAND RESPONSE

New demand response resources are included as options to satisfy the need for new generation capacity. The cost and potential for new demand response is based on *Assessing Demand Response Program Potential for the Seventh Power* Plan,[30] a study completed by Navigant as part of the development of assumptions for the Seventh Power Plan. This study identifies three major categories of demand response programs capable of contributing to the need for winter peaking capability: (1) residential space heating, (2) residential water heating, and (3) interruptible tariffs for agricultural and industrial customers.[31] Measures identified by Navigant are grouped into two bundles according to cost for selection within the optimization; these bundles are summarized in Table 3-7.

[30] Available at: https://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf
[31] While additional types of DR programs are identified in Navigant's study, they are ignored in this work because of their limited potential contributions to meeting regional winter peak needs.

Table 3-7. Assumed of cost and potential for new demand response resources

Program Type	Levelized Cost ($/kW-yr)	Maximum Technical Potential (MW) 2020	2030	2040*	2050*
Ag/Ind Interruptible Tariff	$19	404	535	596	657
Res Space/Water Heating	$59	553	736	819	902
Total		**953**	**1,271**	**1,416**	**1,559**

** 2040 and 2050 potential based on extrapolation, as Navigant study ends in 2035*

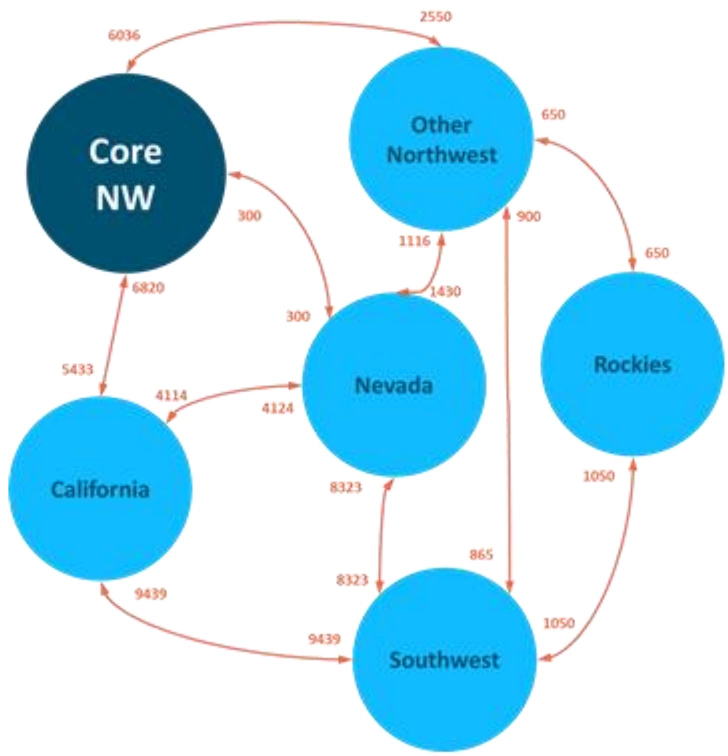
3.7 Transmission Topology

This study divides the Western Interconnection into six zones, using a zonal transmission topology to simulate flows and wholesale trades among the various regions in the Western Interconnection. In addition to the Core Northwest region, the study includes representations of loads and resources in five additional zones: (1) Other Northwest, (2) California, (3) Southwest, (4) Nevada and (5) Rockies. The balancing authorities that are included in each of these zones are listed in Appendix B.

RESOLVE's objective function minimizes the cost of operating the resources to serve load across the six regions simulated, subject to transmission constraints between them. The transmission topology used in this study is based on information compiled from a number of public data sources. Where possible, transfer capability between zones is tied to WECC path ratings, per the WECC 2016 Path Catalog. WECC path ratings are complemented by other available data, including scheduling total transfer capacity provided on the OASIS sites of certain utilities and transmission owners, reported thermal ratings of transmission lines in WECC's nodal TEPPC cases, and conversations with transmission engineers, to approximate actual operations to the extent possible.

Figure 3-10 shows the resulting transmission capacity between the different zones modeled in RESOLVE.

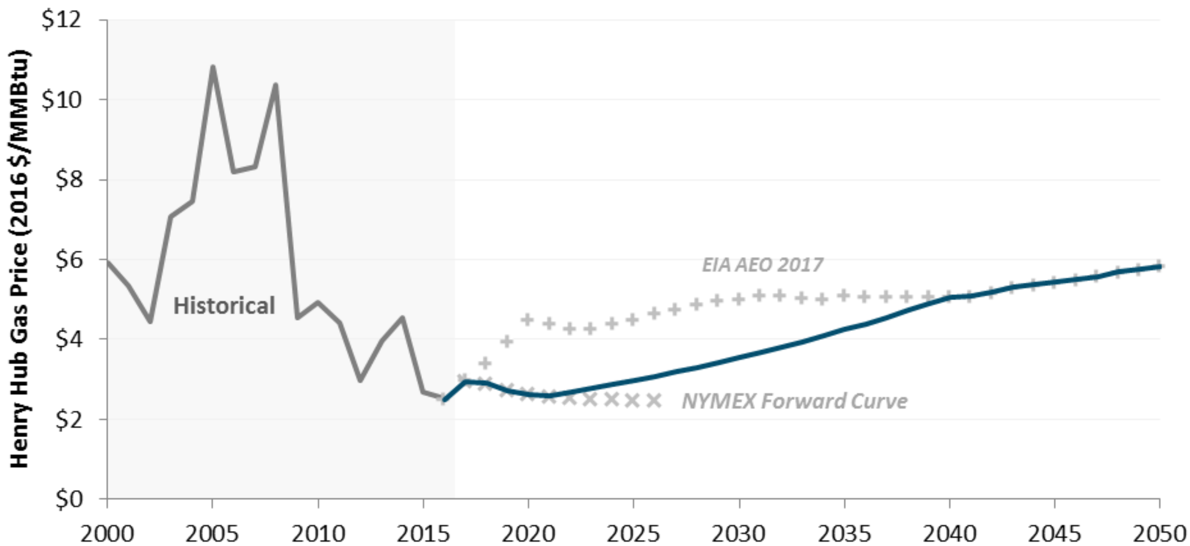
Figure 3-10. Transmission topology used in RESOLVE.



3.8 Fuel Price Forecasts

The gas price forecast used in this study is derived from a combination of market data and fundamentals-based modeling of natural gas supply and demand. In the near term (2017-2021), the price of natural gas at Henry Hub is based on a five-day average of the NYMEX strip obtained between October 2-6, 2017. From 2021-2040, the gas price is assumed to converge towards the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2017 forecast; thereafter (2040-2050), the EIA AEO 2017 forecast is used directly. The resulting annual forecast of Henry Hub natural gas prices is shown in Figure 3-11.

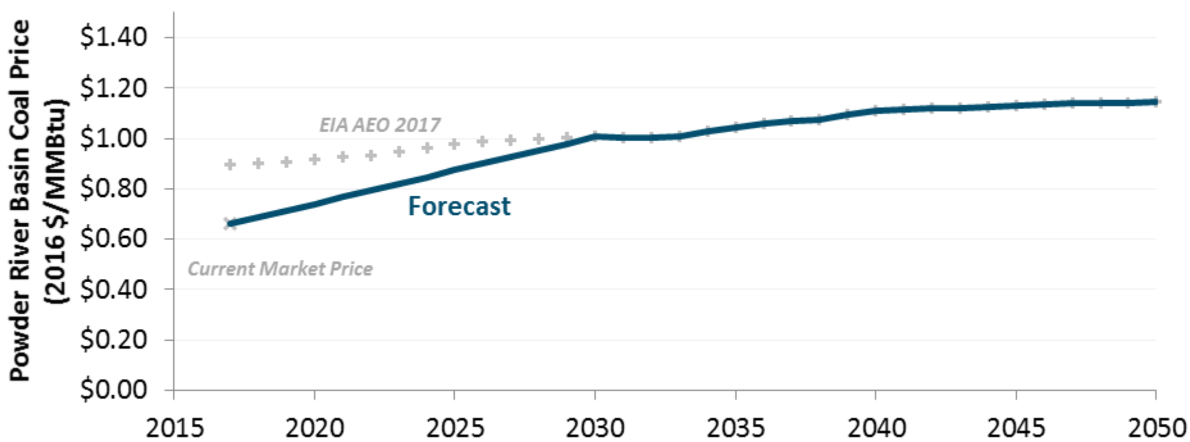
Figure 3-11. Henry Hub gas price forecast



Regional basis differentials and delivery charges are based on the California Energy Commission's Integrated Energy Policy Report (IEPR) and are applied to the Henry Hub commodity price forecast to obtain regional burnertip gas price forecasts. The regional burnertip gas price forecasts for each year modeled in RESOLVE are included in Appendix B. Annual average prices are further shaped according to a monthly profile to capture seasonal trends in the demand for natural gas and the consequent impact on pricing.

The regional coal price assumptions used in this study similarly combines short-term market data with the long-term fundamentals forecast developed in EIA's AEO 2017 for the Powder River Basin commodity price as shown in Figure 3-12. Regional delivery adders are based on data provided by NWPCC developed for the Seventh Power Plan. Regional coal prices for each year of the analysis are included in Appendix B.

Figure 3-12. Long-term commodity price forecast for coal in the Powder River Basin



3.9 Operating Reserves

Three types of operating reserve requirements are imposed within the Core Northwest to capture constraints on the generation fleet in its real-time operations. Reserves are required in system dispatch to prepare for unexpected demand and supply fluctuations and system contingencies. The descriptions of each reserves and the assumptions of reserve requirements are listed below:

+ **Spinning reserves (3% of hourly load)** is held in accordance with NERC operating standards to ensure that, in the event of a contingency or outage, sufficient spinning resources are available to respond within a fifteen-minute period to maintain the stability of the system and prevent a large-scale blackout.[32]

[32] Non-spinning reserves are not modeled explicitly, as it is assumed that sufficient capacity will be available at most times to meet this requirement without difficulty. As such, it would not be a binding constraint in the optimization.

- **Regulation up and down (1% of hourly load)** is held to balance load and generation in real time; generators on Automated Generator Control (AGC) typically respond to a four-second signal to adjust output in response to the needs of the grid.
- **Load following up and down (3% of hourly load),** while not a formal reserve product in most jurisdictions, represents capacity that is reserved to accommodate load and/or renewable forecast error as well as subhourly deviations from hourly forecasts.

Within RESOLVE, each of these reserve products is specified exogenously to the optimization. Theoretically, the quantities of both load following and regulation needed to operate a system reliably should increase with the penetration of variable resources (i.e. wind and solar PV) as intermittency is added to the system. The fact that this effect is not captured in RESOLVE means that, in this respect, RESOLVE understates the full cost of renewable integration; however, in comparison to the more significant impact of renewable curtailment at higher penetrations, this effect is likely small.

The reserve requirements in RESOLVE can be met by flexible resources within the portfolio, subject to the limits of the minimum and maximum capacities. The portfolio of resources that can meet the specified reserve requirements in this study is assumed to include all coal, gas, hydro, and storage resources. Additionally, RESOLVE allows renewable generation to contribute to meeting the needs for load following down; the implicit assumption is that variable renewable generation may be curtailed on a five-minute basis to balance forecast error and subhourly variability.

3.10Greenhouse Gas Accounting Conventions

The conventions used for greenhouse gas accounting within RESOLVE are meant to reflect a consumption-based measure of the greenhouse gases associated with the generation portfolio for the Northwest and are based on the rules established by the California Air Resources Board. The total greenhouse gas emissions attributed to the Core Northwest region includes:

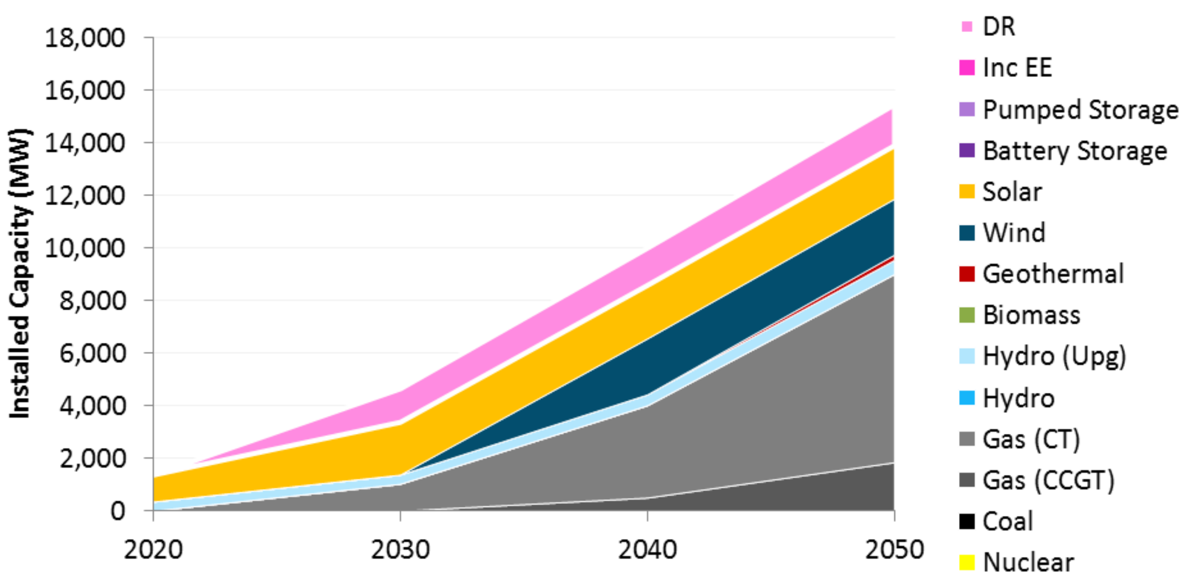
- **In-region generation:** all greenhouse gas emissions emitted by fossil generators (coal and natural gas) within the region, based on the simulated fuel burned and its assumed carbon intensity;
- **External resources owned by Core Northwest utilities:** greenhouse gas emissions emitted by resources located outside the Core Northwest but currently owned by utilities that serve load within the region, based on fuel burn and carbon intensity;
- **"Unspecified" imports to the Core Northwest:** assumed emissions associated with economic imports to the Core Northwest that are not attributed to a specific resource but represent economic flows of power into the region, based on a deemed emissions rate of 0.43 tons/MWh.

4 Core Policy Scenario Results

4.1 Reference Case

Figure 4-1 shows the cumulative new investments selected by RESOLVE in the Reference Case across the full extent of the horizon. The amount of new investment increases over time with growth in the demand for energy and increasingly stringent RPS targets within the region; by 2050, roughly 15,000 MW of new generating capacity is added to the existing fleet.

Figure 4-1. Selected resources by year in the Reference Case



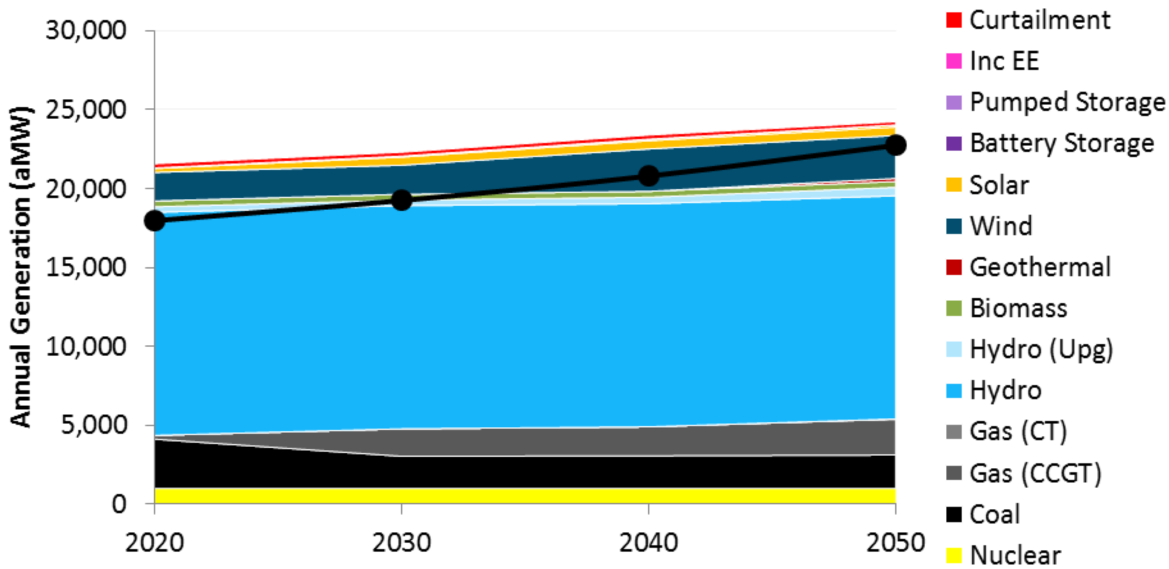
The new investments selected by RESOLVE to meet regional energy and capacity needs through 2050 fall into two categories:

- Roughly 5,000 MW of new renewable generation is added within the region, predominantly to maintain compliance with increasing regional RPS goals. The resources added to meet regional RPS goals comprise a diverse mix, including roughly 2,100 MW of wind; 2,000 MW of solar PV; 200 MW of geothermal; and 600 MW of hydro upgrades.
- Over 10,000 MW of new capacity resources are added to meet the region's growing need for peaking capability. Near-term coal retirements coupled with long-term load growth drive a need for new investments in generation capacity to ensure that the regional fleet has sufficient capacity to meet peak demand. In the Reference Case, this need is met by a combination of demand response (1,600 MW—the full potential assumed available in the model), existing gas combined cycles repowered at the end of their assumed economic lives (1,800 MW), and new gas combustion turbines (7,200 MW). Notably, most of new gas generation resources added to meet capacity needs are low-cost combustion turbines, which operate infrequently but reinforce the reliability of the system in the rare circumstances that they are needed.

Figure 4-2 shows the evolution of the annual generation mix for the entire Core Northwest generation fleet between 2020 and 2050. The region's hydroelectric fleet makes up most of generation produced within the region—roughly 14,000 aMW—while coal, gas nuclear, and wind each contribute significantly to the remaining energy needs within the region. Several trends are notable:

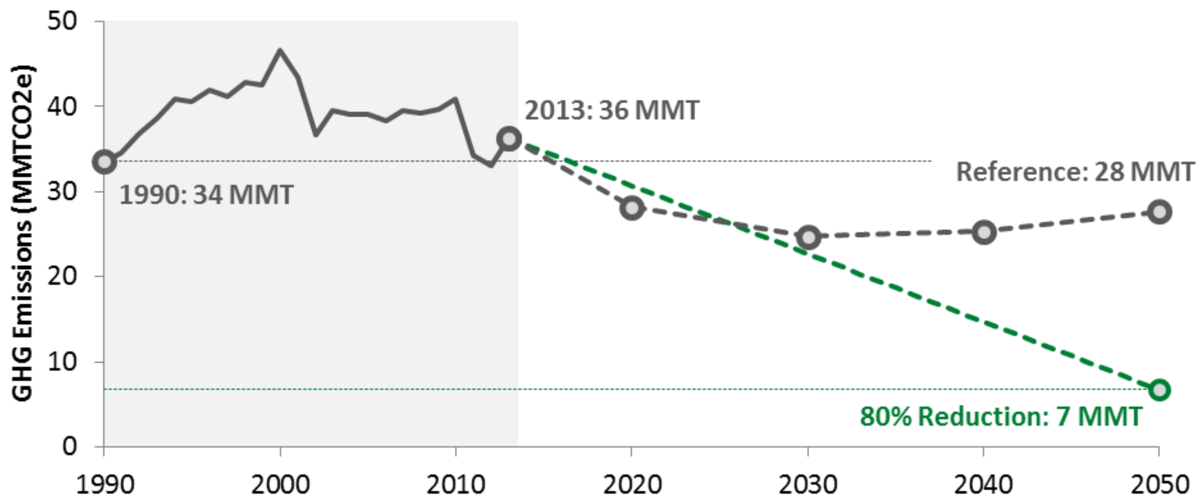
- The anticipated retirements of Boardman, Colstrip 1 and 2, and Centralia result in a decrease in regional coal generation and an increased reliance on natural gas generation between 2020 and 2030.
- The region remains a net exporter of energy to other parts of the Western Interconnection throughout the analysis—albeit to a lesser extent by 2050, as load growth results in slightly lower levels of net export from the Core Northwest to California and other parts of the West. Over the course of the analysis, the region's net export shrinks from 3,300 aMW in 2020 to 1,300 aMW in 2050, as increasing shares of existing hydro serve local loads instead of being exported.

Figure 4-2. Annual generation mix by year, Reference Case



Under the Reference Case, anticipated coal retirements and RPS-driven additions of renewable generation contribute to an overall anticipated reduction in emissions attributed to the region—a reduction that is largely consistent, through 2030, with the downward trajectory needed to meet an 80% reduction goal in the electric sector by 2050 (shown in Figure 4-3). However, after 2030, emissions within the electric sector turn upward, increasing through 2050 as new load growth is met primarily by increased dispatch from natural gas generators. Consequently, by 2050, emissions within the electric sector are estimated to be 28 million metric tons—roughly 21 million metric tons above the 2050 goal of 7 million metric tons.

Figure 4-3. Regional greenhouse gas emissions in the Reference Case



4.2 Carbon Cap Cases

The Carbon Cap scenarios investigated in this study identify the least-cost combination of investments and operational decisions to achieve 40%, 60%, and 80% reductions in emissions in the electric sector by 2050. Each of these resource portfolios combine three primary instruments to achieve an emissions reductions goal at least cost:

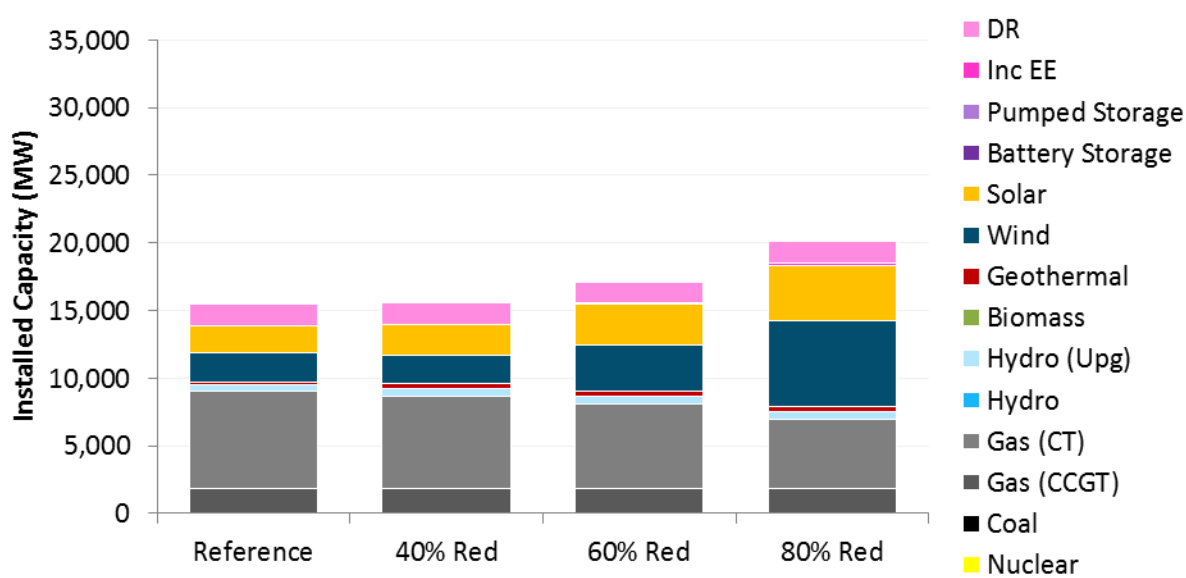
+ **Coal displacement:** imposing a cap on carbon introduces an implicit carbon cost in the dispatch decision for existing coal and gas resources; as the carbon cap becomes increasingly stringent, this implicit price begins to shift the merit order of coal and gas in the dispatch stack—because of its lower fossil intensity, natural gas plants become a lower cost source of generation than existing coal plants. Under an 80% reduction goal, all coal generation is eliminated.
+ **Investment in new renewables:** the implicit carbon price also incents incremental investment in new zero-carbon renewable generation above existing statutory requirements, as the implicit carbon price increases the value of carbon-free power on the wholesale market. In the 80%

Reduction scenario, total investment in new renewables increases to 11 GW by 2050—more than double the new capacity added in the Reference Case.

+ **Investment in incremental energy efficiency:** the implicit carbon price also shifts the cost-effectiveness threshold for energy efficiency measures, increasing the amount of potential available under the total resource cost test. Under the 80% Reduction scenario, 231 aMW of energy efficiency measures are selected.[33]

The role of these three building blocks in facilitating a transition to a low carbon grid in the Northwest is shown in Figure 4-4 (which highlights the incremental investments in renewables and efficiency) and in Figure 4-5 (which shows the displacement—and eventual retirement—of coal from the generation mix).

Figure 4-4. Cumulative new generation capacity by 2050, Carbon Cap scenarios



[33] While this is limited in comparison to the amount of new investment in renewables, this is largely due to the limited available potential identified by the Seventh Power Plan beyond the current cost-effectiveness threshold. The "High Energy Efficiency Potential" scenario explores the impacts of an extended energy efficiency supply curve on the achievement of carbon goals at reasonable cost.

Figure 4-5. Regional generation mix in 2050, Carbon Cap scenarios

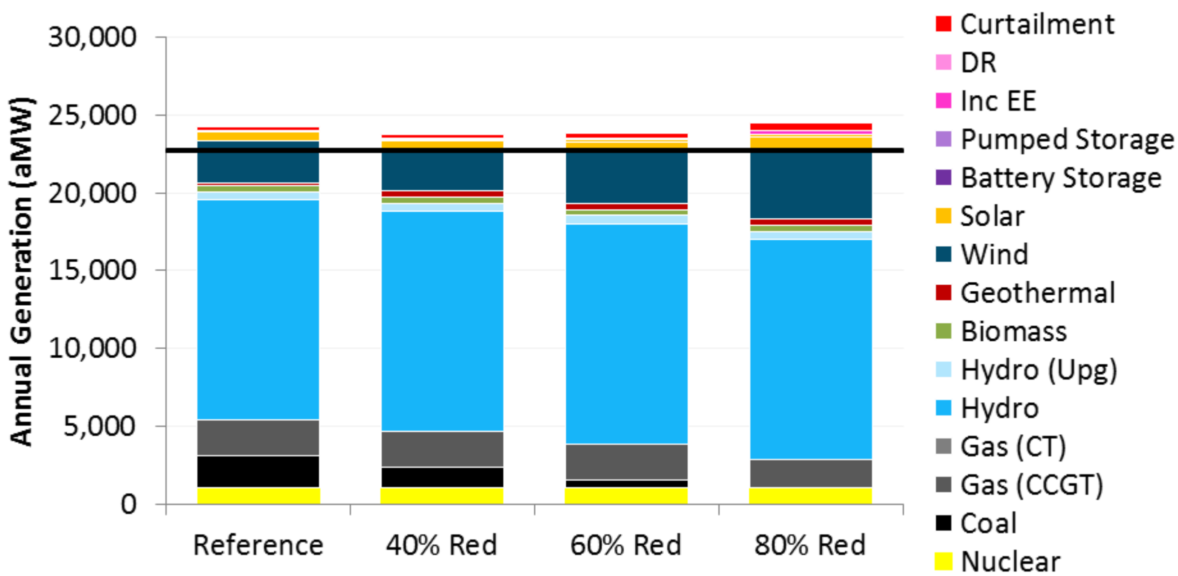


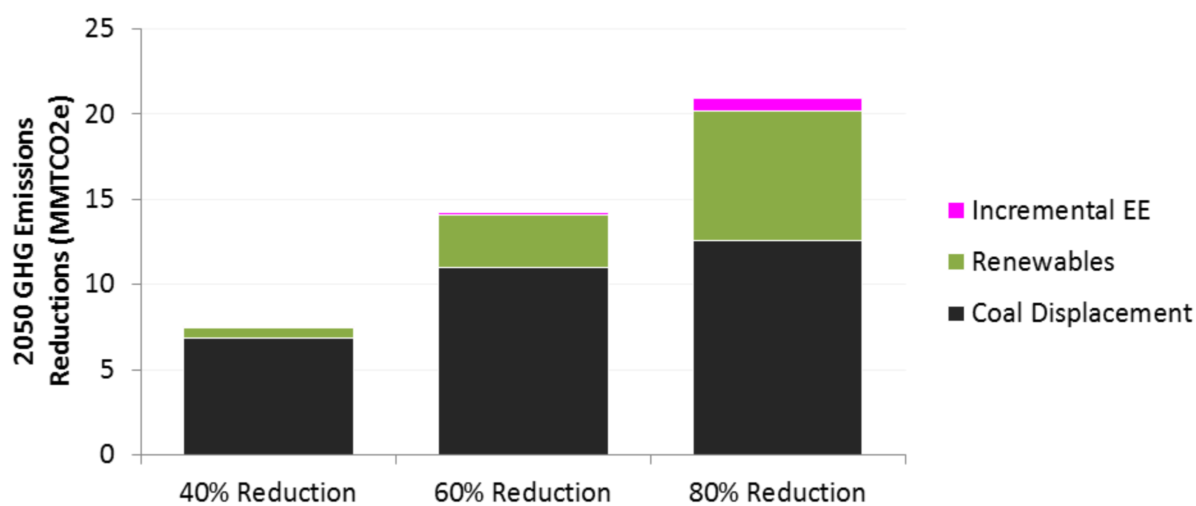
Table 4-1. Cost and emissions impacts of Carbon Cap scenarios in 2050 relative to Reference Case

		40% Reduction	60% Reduction	80% Reduction
Incremental Fixed Costs ($MM/yr)	Renewables	$160	$526	$1,227
	Transmission	—	$118	$342
	Storage	—	—	—
	Natural Gas	-$51	-$134	-$160
	DR/EE	$29	$59	$253
Incremental Operating Costs ($MM/yr)		$24	-$135	-$615
Total Incremental Costs ($MM/yr)		**$163**	**$434**	**$1,046**
Greenhouse Gas Emissions Reductions (MMTCO2e)		**7.5**	**14.2**	**20.9**
Average Carbon Abatement Cost ($/tonne)		**$22**	**$30**	**$50**

The cost and emissions impacts of each of the three Carbon Cap scenarios, measured relative to the 2050 Reference Case, are summarized in Table 4-1. The cost of meeting incremental carbon reduction goals from 40% to 80% increases, reflecting a growing marginal cost of carbon displacement. In the 80% Reduction scenario, through a combination of the three strategies described above, the emissions reductions of 21 million metric tons are achieved for a net cost of $1 billion.

The achievement of emissions reductions goals at relatively low cost—up to an average cost of $50/tonne in the 80% Reduction scenario—reflects the fact that each scenario combines the least-cost combination of greenhouse gas abatement measures to minimize costs to ratepayers. The composition of the greenhouse gas emissions reduction "portfolios," shown in Figure 4-6, highlight important relationships between the building blocks of an emissions reduction strategy. First, the lowest hanging fruit for greenhouse gas reductions in the region is displacement of remaining coal generation: under the 40% Reduction scenario, nearly all abatement is achieved through reduced dispatch of remaining coal generation in the portfolio. Second, meeting higher levels of greenhouse gas reduction at reasonable cost will require a combination of measures: to meet higher emissions reduction goals, the 60% Reduction and 80% Reduction combine coal displacement with increased investment in new renewable generation and energy efficiency.

Figure 4-6. Sources of emissions reductions in each Carbon Cap scenario.



4.3 Carbon Tax Cases

The results of the Carbon Tax cases are directionally consistent with the Carbon Cap cases—by applying an explicit price to carbon emissions, the Carbon Tax cases suppress output from remaining coal plants while providing an incentive for incremental investments in renewables and energy efficiency. Figure 4-7 shows the cumulative new investments in generation resources in 2050 in the Carbon Tax scenarios, and Figure 4-8 shows the annual generation mix. The key changes observed in the Carbon Tax scenarios are:

+ Under both carbon tax proposals, the price on carbon is sufficient to displace all remaining coal generation from the portfolio, resulting in no generation from those resources by 2050.
+ Both carbon taxes also lead to additional investments in renewables—3,700 MW of additional wind and solar in the Governor's proposed tax and 4,100 MW in the Legislature's proposed tax—as well as additional energy efficiency—100 aMW in both scenarios.

Figure 4-7. Cumulative new generation capacity by 2050, Carbon Tax scenarios

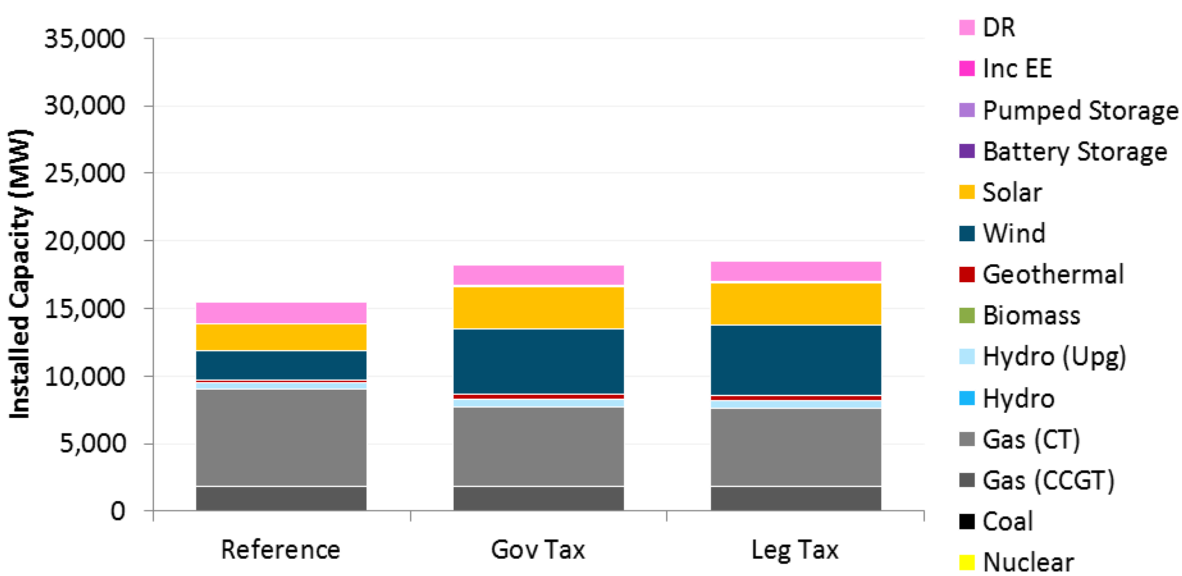
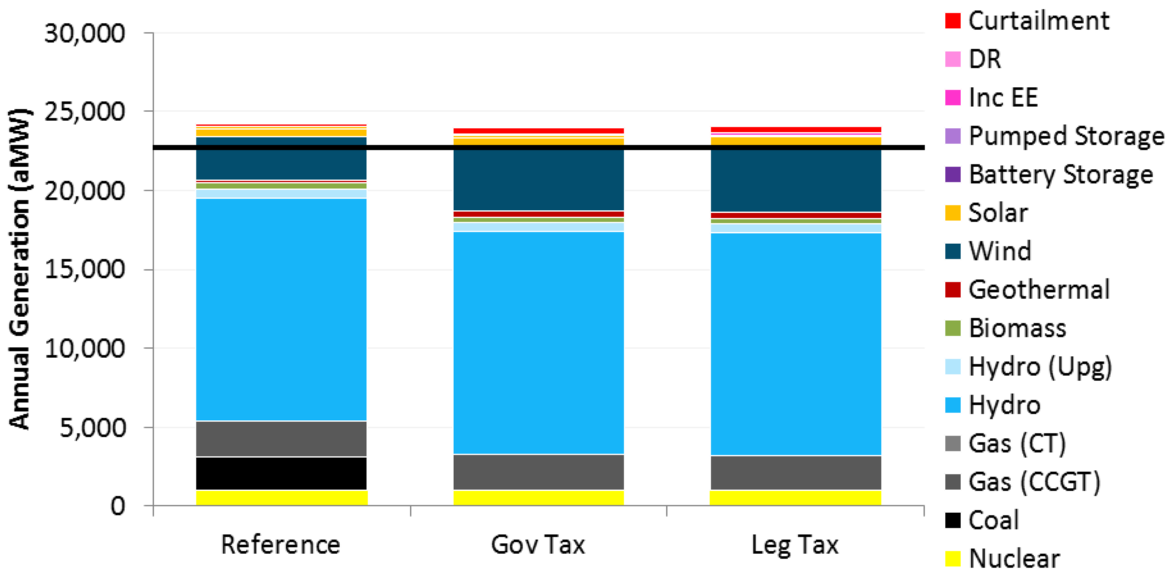


Figure 4-8. Regional generation mix in 2050, Carbon Tax scenarios



The cost and emissions impacts resulting from the investments and dispatch decisions are shown in Table 4-2. Like in the Carbon Cap cases, the Carbon Tax scenarios result in increased investment costs in renewables (and associated transmission) and energy efficiency, a reduction in investments in new conventional generation, and a reduction in operating costs through displacement of coal and gas. The two scenarios each yield approximately 19 million metric tons of emissions reductions in 2050—sufficient to meet a reduction goal of about 70% relative to 1990 levels.

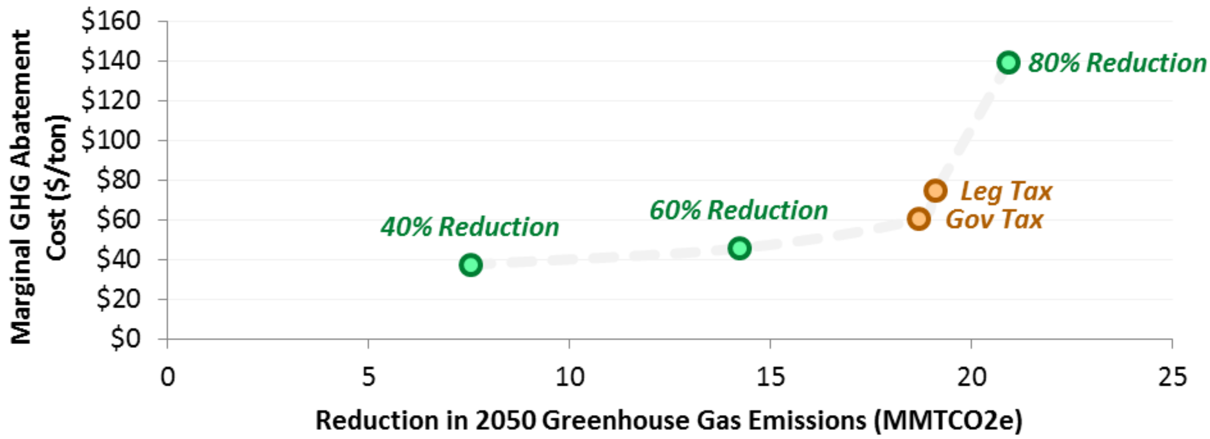
Table 4-2. Cost and emissions impacts of Carbon Tax scenarios in 2050 relative to Reference Case

		Gov Tax	Leg Tax
Incremental Fixed Costs ($MM/yr)	Renewables	$786	$847
	Transmission	$247	$269
	Storage	—	—
	Natural Gas	-$53	-$60
	DR/EE	$96	$96
Incremental Operating Costs ($MM/yr)		-$301	-$348
Total Incremental Costs ($MM/yr)		**$775**	**$804**
Greenhouse Gas Emissions Reductions (MMTCO2e)		**18.7**	**19.1**
Average Carbon Abatement Cost ($/tonne)		**$41**	**$42**

These outcomes—both the impacts on investments and operations as well as the overall cost and emissions impacts of the Carbon Tax scenarios—are consistent with the results observed in the Carbon Cap cases. Whereas the Carbon Cap scenarios apply an implicit price to carbon emissions, the Carbon Tax scenarios do so explicitly. The effect on the optimization of the portfolio is effectively identical and is only a matter of degree; under the assumptions used in this study, both carbon tax proposals yield emission reductions equivalent to approximately 70% reductions relative to 1990 levels. As shown in Figure 4-9—the marginal greenhouse gas abatement cost curve as a function of the level of abatement—this result is expected at the carbon prices modeled in these scenarios.[34]

[34] While this analytical framework does suggest a certain equivalence between carbon cap and carbon tax policies, the two have different implications for risk. The deterministic framework used in this study results in a deterministic outcome for greenhouse gas emissions under a carbon tax. In reality, a carbon tax provides a stable price signal but does not provide a certain emissions reduction outcome; in contrast, a carbon cap will guarantee a specified level of greenhouse gas reductions but could lead to volatile or unanticipated allowance pricing. This distinction between the two policies is explored further through sensitivity analysis in Sections , which highlights the risks associated with each.

Figure 4-9. Comparison of marginal abatement costs in Carbon Cap and Tax scenarios



The shape of the marginal greenhouse gas abatement cost provides a clear picture of both the presence of "low-hanging fruit" to achieve moderate levels of decarbonization as well as the challenges of achieving deep decarbonization. Under less stringent carbon regimes, the abatement curve is relatively flat and low—gradually increasing from a marginal cost of $40/tonne in the 40% Reduction scenario to $50/tonne in the 60% Reduction scenario. Meeting these levels of emissions reductions is possible at relatively low cost, largely through the displacement of coal with gas and the lowest-cost renewable resources. While this trend continues beyond the 60% Reduction goals, the abatement curve eventually turns sharply upwards, taking on an exponential character; once all of the coal has been displaced and the lowest cost renewables developed, the marginal decarbonization measures within the electric sector become increasingly expensive. In the 80% Reduction scenario, the marginal cost has increased to $140/tonne, reflecting the marginal cost of renewable investments that provide the last units of greenhouse gas emissions reductions needed to meet this goal.

4.4 High RPS Cases

As shown in Figure 4-10, the imposition of an increased regional RPS goal has the predictable impact of increasing the amount of new renewable generation selected in each portfolio. Whereas the Reference Case includes 5 GW of new renewables by 2050, the 30%, 40%, and 50% RPS scenarios result in 10 GW, 16 GW, and 23 GW of new renewable capacity. At the same time, the amount of new gas capacity in the High RPS scenarios is similar to the Reference Case; because the incremental wind and solar resources are variable and intermittent and do not provide significant capacity value, a significant amount of gas capacity is selected along with the large renewable buildout.

Figure 4-10. Cumulative new generation capacity by 2050, High RPS scenarios

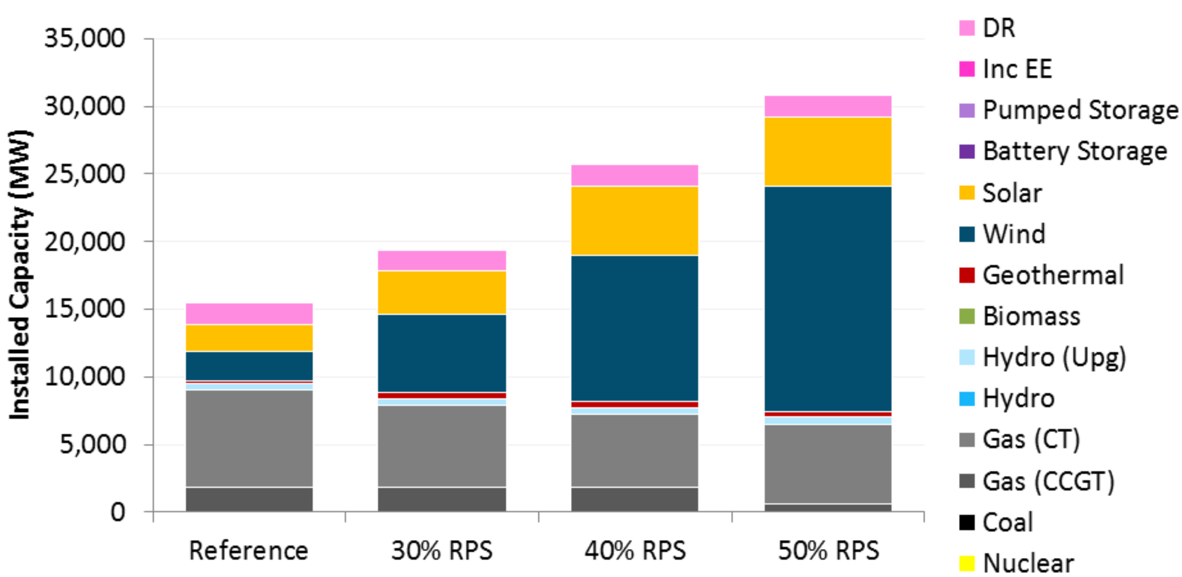


Figure 4-11. Annual generation mix in 2050, High RPS scenarios

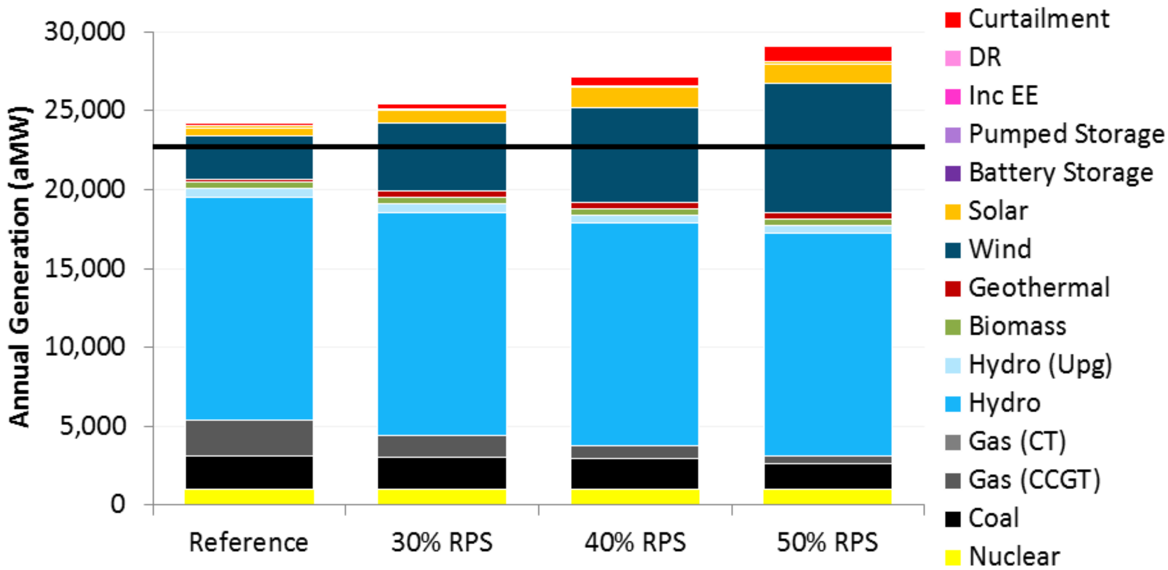


Table 4-3. Cost and emissions impacts of High RPS scenarios in 2050 relative to Reference Case

Study		30% RPS	40% RPS	50% RPS
Incremental Fixed Costs ($MM/yr)	Renewables	$984	$2,249	$3,478
	Transmission	$310	$614	$1,285
	Storage	—	—	—
	Natural Gas	-$167	-$268	-$376
	DR/EE	—	—	—
Incremental Operating Costs ($MM/yr)		-$797	-$1,517	-$2,241
Total Incremental Costs ($MM/yr)		**$330**	**$1,077**	**$2,146**
Greenhouse Gas Emissions Reductions (MMTCO2e)		**4.3**	**7.5**	**11.5**
Average Carbon Abatement Cost ($/tonne)		**$77**	**$144**	**$187**

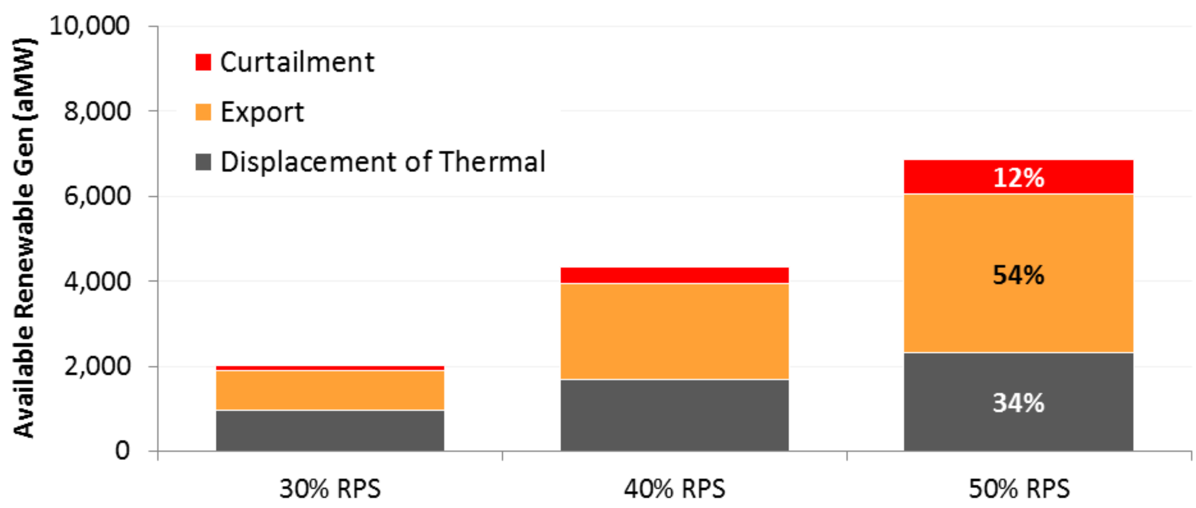
The cost of achieving greenhouse gas reductions through an increased RPS policy is high compared to policies directly focused on carbon. Several factors contribute to the magnified cost of the High RPS policy scenarios.

First, the cost of investments in renewables is magnified by renewable integration challenges that grow with increasing renewable penetration. The primary among these challenges is renewable curtailment—during periods when the combined production of the hydro system and renewables exceeds the combined load and export capability from the region, renewables must be curtailed to maintain an instantaneous balance between load and generation. Historically, the Northwest has experienced such oversupply events during high hydro conditions, requiring operators to spill water to balance loads and resources; increasing regional RPS targets will increase both the magnitude and frequency of these events. By requiring utilities to procure additional renewable resources to replace the foregone renewable energy credits (RECs) lost due to curtailment, this dynamic quickly drives up costs to ratepayers at higher penetrations of renewables.

The other factor that contributes to the significant cost of meeting a high RPS goal regionally is the need to invest in new transmission to deliver renewables to loads. While this study does not focus directly on the transmission impacts of meeting high renewable goals, RESOLVE does consider transmission costs when selecting among new renewable generation. This study assumes that a significant amount of renewable generation can be developed in the Northwest without requiring significant transmission upgrades. However, the amount of generation needed to meet a 50% RPS would undoubtedly require significant reinforcement in existing corridors as well as investment in new resources. In the 50% RPS cost, the incremental cost of transmission upgrade alone exceeds $1.2 billion per year—more than the cost to reach the 80% Reduction goal through a least-cost combination of measures.

The ineffectiveness of increasing regional RPS goals as a greenhouse gas reduction strategy is not only a result of its relatively high cost, but its limited impact on regional emissions as well: a regional 50% RPS scenario results in 11 million metric tons of carbon abatement relative to the Reference Case—roughly half the reductions needed to meet an 80% reduction goal by 2050. The relative ineffectiveness of continuing to invest in renewable generation results from the impact that increasing amounts of renewables have on system operations. Figure 4-12 shows the how incremental renewable generation impacts the Northwest electric system in three ways: (1) a portion of it displaces fossil resources that would otherwise operate within the Northwest; (2) a portion of it is exported to other parts of the West, sold in wholesale markets; and (3) a portion of it is curtailed, with no benefit to ratepayers in the Northwest. As the penetration of renewables increases, the share of incremental generation that is exported to other regions—and thus provides no direct greenhouse gas benefit to the region—increases; under a 50% RPS, over half of all incremental renewable generation added is exported to other regions, and only a third directly displaces fossil resources within the region. At the same time, coal continues to operate to serve the needs of the Northwest, resulting in a limited impact on greenhouse gas emissions in the Northwest.

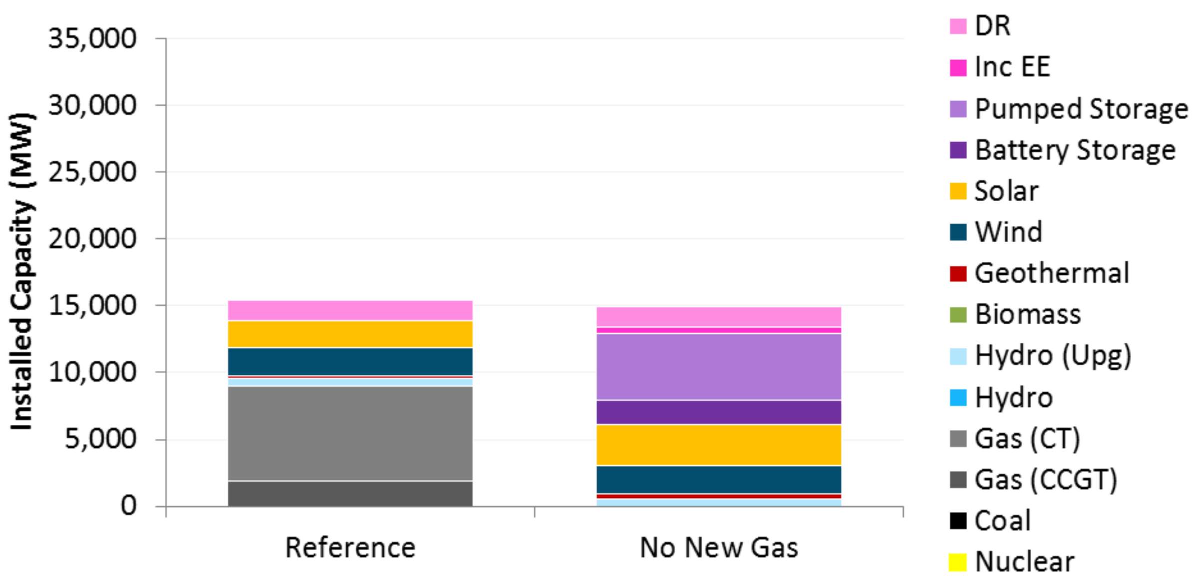
Figure 4-12. Impact of renewables added incremental to the Reference Case in 2050



4.5 No New Gas Case

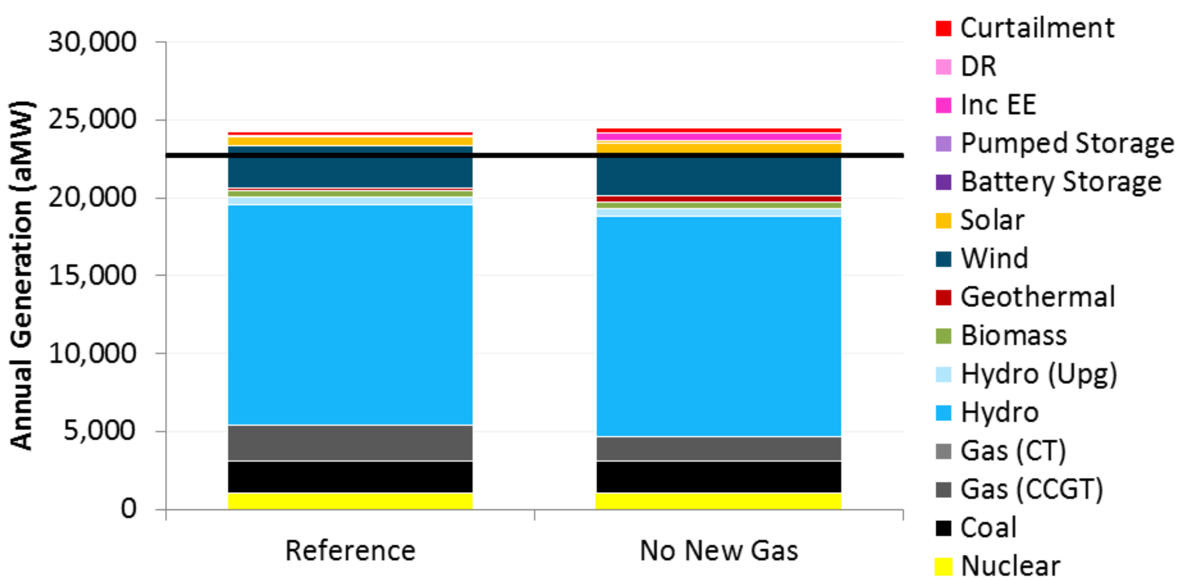
In the 'No New Gas' scenario, further investments in new natural gas generation are prohibited in the optimization of the portfolio. One of the major drivers of new investment across all scenarios is the need for new generation capacity to meet regional reliability needs, as both sustained load growth and planned coal retirements create a need for new firm resources. In all other scenarios, this need is met predominantly with investment in low-cost gas combustion turbines; in this scenario, the primary effect of the prohibition of new gas is the substitution of energy storage to meet the regional needs for peaking capability. As shown in Figure 4-13, the No New Gas scenario comprises 5,000 MW of pumped storage and 2,000 MW of battery storage, as well as modest increases in the amount of renewable generation and energy efficiency relative to the Reference Case.

Figure 4-13. Cumulative new generation capacity by 2050, No New Gas scenario



While the portfolio of resources selected to meet regional needs in the 'No New Gas' scenario is dramatically distinct from the Reference Case, the regional generation mix, shown in Figure 4-14, does not change substantially. The primary type of new investment in the No New Gas scenario—energy storage—does not produce energy; in fact, due to the roundtrip losses, it is a net consumer of energy over the course of the year. As a result, the addition of energy storage to the portfolio has little impact on the amount of generation produced by different types of resources over the course of the year. In fact, the minor differences in the generation mix shown in Figure 4-14 can be attributed not to the inclusion of energy storage, but to the incremental energy efficiency and renewables that are selected to meet regional needs.

Figure 4-14. Annual generation mix in 2050, No New Gas scenario



Thus, among the policy mechanisms considered in this study, the prohibition of new natural gas generation is the least effective mechanism to reduce greenhouse gas emissions within the electric sector. The investments in energy storage identified in this scenario come at great expense to ratepayers—as summarized in Table 4-4 over $1.1 billion in annual costs in 2050—but do not provide any direct greenhouse gas benefit to the region.

Table 4-4. Cost and emissions impacts of No New Gas scenario in 2050 relative to Reference Case

		No New Gas
Incremental Fixed Costs ($MM/yr)	Renewables	$244
	Transmission	—
	Storage	$2,131
	Natural Gas	-$1,350
	DR/EE	$559
Incremental Operating Costs ($MM/yr)		-$403
Total Incremental Costs ($MM/yr)		**$1,181**
Greenhouse Gas Emissions Reductions (MMTCO2e)		**2.0**
Average Carbon Abatement Cost ($/tonne)		**$592**

The implications of a prohibition on new gas capacity within the region also has potential implications for electric reliability that are not directly addressed in RESOLVE. RESOLVE ensures that each portfolio meets a regional planning reserve margin—that is, each portfolio has sufficient dependable generation capacity to meet a single hour peak demand. However, electric reliability in the Northwest—where, under low hydro conditions, the capability of the hydro fleet to sustain output across multiple days may be limited—ensuring reliability.

While adding large quantities of energy storage will increase the region's ability to meet growing single-hour peak demands, it does not address the region's need for sustained energy production across a longer time horizon. Accordingly, unlike any of the other portfolios developed in this study, the 'No New Gas' scenario may result in a degradation of electric sector reliability, and may require significant new investment beyond those identified in this analysis at much larger costs to the region.

5 Core Policy Scenario Implications

5.1 Cost and Emissions Impacts

The primary metrics used to assess the relative effectiveness of each policy are (1) the 2050 incremental total cost relative to the Reference Case, and (2) the 2050 emissions reductions achieved relative to the Reference Case. Figure 5-1 summarizes the performance of each of the Core Policy scenarios in each of these two dimensions. These and other key metrics are shown in Table 5-1.

Figure 5-1. Summary of cost and emissions impacts relative to the Reference Case, 2050

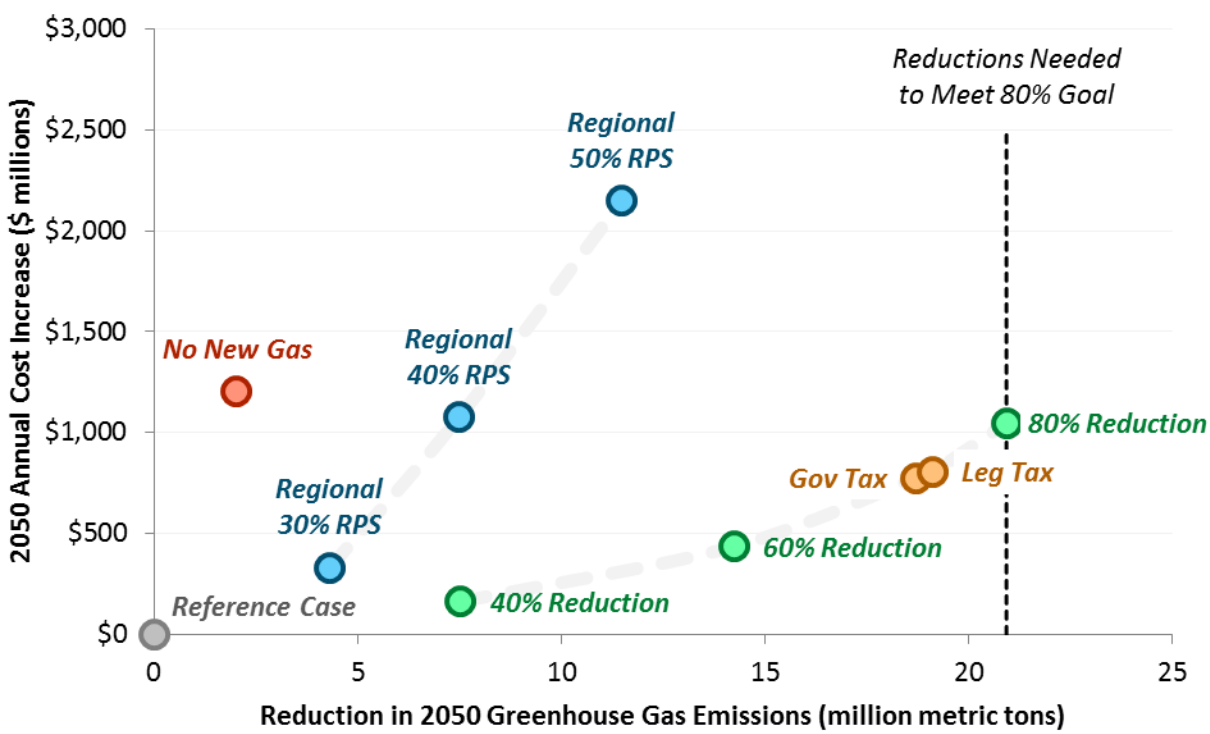


Table 5-1. Key 2050 metrics for Core Policy scenarios

Scenario		Total Annual Revenue Requirement ($MM/yr)	Average Rate Impact (%)	Annual Incremental Cost ($MM/yr)	Total GHG Emissions (MMTCO2e)	GHG Reductions (MMTCO2e)	Average Abatement Cost ($/tonne)	Effective RPS (%)	Effective Zero Carbon Gen (%)
Reference		$18,414	—	—	27.6	—	—	20%	91%
Carbon Cap	40% Reduction	$18,577	+1%	+$163	20.1	7.5	$22	21%	92%
	60% Reduction	$18,848	+2%	+$434	13.4	14.2	$30	25%	95%
	80% Reduction	$19,460	+6%	+$1,046	6.7	20.9	$50	31%	102%
Carbon Tax	Gov Tax	$19,219	+4%	+$775	8.5	18.7	$41	28%	99%
	Leg Tax	$19,189	+4%	+$804	8.9	19.1	$42	28%	99%
High RPS	30% RPS	$18,745	+2%	+$330	23.3	4.3	$77	30%	101%
	40% RPS	$19,492	+6%	+$1,077	20.1	7.5	$144	40%	111%
	50% RPS	$20,561	+12%	+$2,146	16.2	11.5	$187	50%	121%
No New Gas		$19,616	+7%	+$1,202	25.6	2.0	$592	22%	93%

Figure 5-1 highlights the relative differences among different policy mechanisms as greenhouse gas abatement tools:

- The **Carbon Cap** scenarios define an efficient frontier for the least-cost policies to achieve emissions reduction goals. Meeting the 80% reduction goal by 2050 can be achieved at an incremental cost of approximately $1 billion per year.
- The **Carbon Tax** scenarios lie along this efficient frontier; this is largely consistent with microeconomic theory that both a cap and a price can be used to achieve a least-cost portfolio of emissions reductions.[35] The tax levels modeled in this study ($61/tonne and $75/tonne) are each sufficiently high to yield approximately 70% emissions reductions by 2050.
- In comparison to the scenarios driven by carbon pricing, the **High RPS** scenarios result in significantly higher cost while yielding significantly lower greenhouse gas reductions. The cost of the 50% RPS case—over $2 billion per year—is more than double the 80% Reduction scenario, while the emissions reductions that it yields—11 million metric tons per year—are roughly half of what is needed to reach the 80% reduction target.
- The **No New Gas** case offers the least effective mechanism for addressing greenhouse gas emissions within the region: the investments in energy storage made in the stead of new natural gas come at a significant cost premium but produce no carbon free generation. The incremental cost of the No New Gas case ($1,181 million per year in 2050) is roughly equivalent to the cost of achieving the 80% reduction goal, yet it provides less than one tenth the emissions reductions needed to meet that goal.

It is worth noting that the emissions impact attributed to each scenario do depend on the emissions accounting conventions used in this study. This study uses, for the sake of greenhouse gas accounting for the Core Northwest portfolio, the current California Air Resources Board convention. Under those accounting rules, generation that is exported has no impact on the greenhouse gases attributed to the

[3535] While both policies can be used to achieve least-cost emissions reductions, they do not provide the same market signals

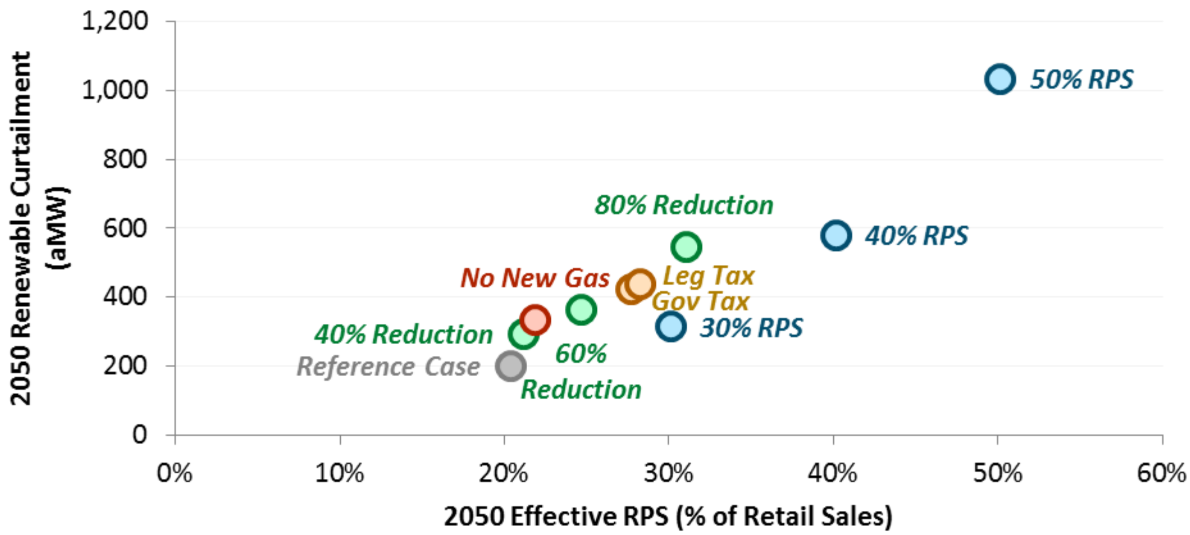
Core Northwest utilities. Further, imports from other states are assumed to be unspecified and attributed a default emission rate equivalent to an efficient natural gas plant. In reality, when renewable generation is sold in external markets throughout the West, it will frequently displace a fossil resource at the margin—most often natural gas. As a result, there may be physical emissions reduction achieved in the High RPS scenarios that is not attributed to electric utilities in the Core Northwest.

5.2 Renewable Curtailment

The portfolios developed under the Core Policy scenarios span a wide range of renewable penetration, ranging from the 20% RPS (Reference Case) to 50% RPS. This wide range highlights how increasing penetrations of renewables will impact system operations in the Northwest region, and, in particular, the emerging role of renewable curtailment as a crucial tool to manage the variability of renewables at high penetrations. The Pacific Northwest has a long history of oversupply management—both in recent years through BPA's curtailment of wind generation during periods of oversupply and from a longer historical perspective during periods of high hydro runoff—but as the penetration of renewable generation in the region increases, these types will increase in magnitude and frequency. In these events, the ability for system operators to curtail renewables during these periods is a crucial tool to maintain system reliability while managing the variability of high penetrations of wind and solar PV. At the same time, increasing levels of renewable curtailment will impose additional costs on ratepayers. This section explores the nature of renewable curtailment observed in these scenarios.

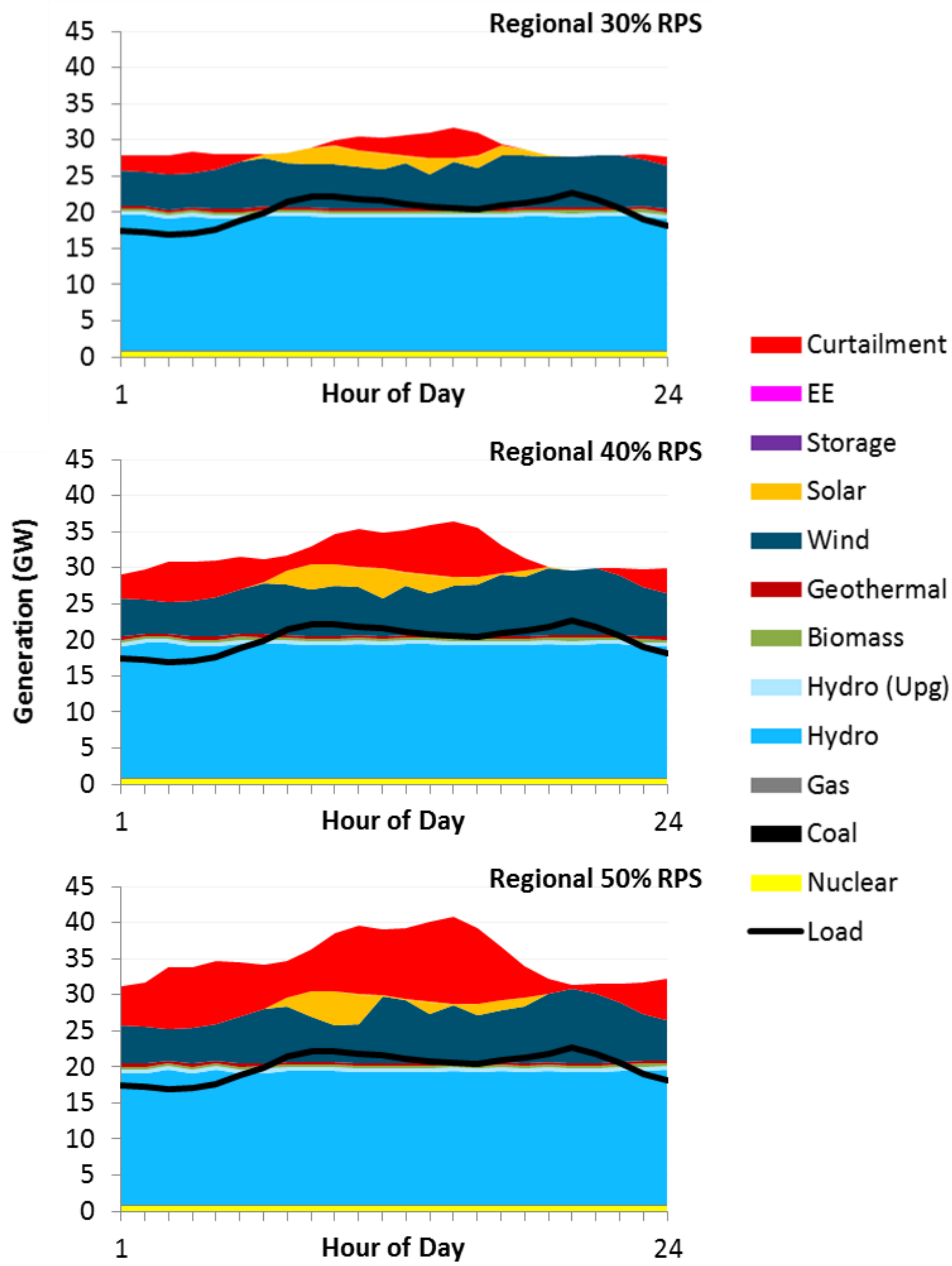
All scenarios analyzed in this study exhibit some level of curtailment, which generally increases as a function of renewable penetration. Figure 5-2 shows the renewable curtailment in each scenario as a function of the effective level of RPS penetration achieved in each scenario.

Figure 5-2. 2050 renewable curtailment across Core Policy scenarios



While all scenarios show some amount of renewable curtailment, the High RPS scenarios, which span the largest range in renewable penetration, provide the best illustration of the role of renewable curtailment at higher renewable penetration. Figure 5-3 displays a day on which the capability of the hydro fleet alone is nearly sufficient to meet regional loads to demonstrate the growing magnitude of the renewable integration challenge in each of the High RPS scenarios. The day highlighted in Figure 5-3 reflects high hydro conditions such that the addition of incremental zero marginal cost generation eventually requires curtailment when surplus cannot be sold to other regions. These types of events become much more frequent and larger in magnitude as RPS policy increases: as the RPS policy increases from 20% to 50%, the percentage of available renewable generation that is curtailed annually increases from 4% to 9%.

Figure 5-3. Increasing renewable curtailment observed with increasing regional RPS goals



While curtailment is an important tool for operators to balance generation and load at high renewable penetrations, it also results in increased costs to ratepayers: while the full fixed costs of investment in renewables are incurred by ratepayers, no value is recovered during periods when renewables must be curtailed. Under an RPS policy, the dynamics of renewable curtailment also introduce distortions into wholesale markets: because each utility has a production quota for renewable generation, when a unit of renewable generation is curtailed, a utility must secure a “replacement” resource to replace the foregone renewable energy credit from the curtailed resource. The need for replacement resources results in a portfolio that is built capable of producing more renewable generation than is needed to meet the statutory requirement, resulting in additional costs to utilities.

While this study’s finding regarding the critical role of renewable curtailment is consistent with a range of studies of high renewable penetrations in other jurisdictions, the character of the renewable curtailment dynamics observed in this study are distinctly different from other areas and reflect the unique characteristics of the Pacific Northwest electricity system. In particular, the characteristics of curtailment events observed in the Pacific Northwest are distinctly different from those anticipated in California at high renewable penetrations. While the expected patterns of curtailment in California are likely to be driven by high penetrations of solar PV and will generally coincide with the hours of maximum solar PV production each day, curtailment events in the Pacific Northwest will be driven by high combined output from the hydro system and wind fleet, lasting for much longer periods—days, weeks, or event months depending on the underlying hydro conditions. Figure 5-3 hints at the round-the-clock nature of curtailment events in the Pacific Northwest.

The distinctive daily and seasonal patterns of curtailment characteristic to a region with significant hydro and wind resources have direct implications on the types of renewable integration solutions that provide the most benefit to the system as a whole—and help explain why this study identifies very little value for new investments in energy storage as a facilitating technology for high renewable penetrations in the Pacific Northwest. This finding again distinguishes the Pacific Northwest from California, where previous analyses have identified significant potential value in new investments in energy storage to facilitate California's achievement of high renewable policy goals. The reason for this distinction is rooted in the different characteristics of curtailment events. In California, curtailment events are expected to last on the order of four to eight hours during periods of oversupply, but will recur on a daily basis. This regular, periodic dynamic is well suited to balancing with energy storage technologies, which can charge during curtailment hours and discharge during the evening peak, cycling on a daily basis as a high value application. In contrast, such storage devices would find infrequent opportunities to cycle in the Northwest, as curtailment events with less predictability and significantly longer duration do not lend themselves to balancing with relatively short duration storage.

5.3 Regional Capacity Need

The three major regional planning efforts—NWPCC's *Seventh Power Plan*, BPA's White Book, and PNUCC's *Northwest Regional Forecast*—identify a potential need for new generation capacity in the mid-2020s, driven primarily by anticipated coal retirements. Across all scenarios, this study's results are consistent with the proposition that new firm capacity will be needed in this timeframe; with continued load growth through 2050, new investments in generation capacity will be needed to ensure reliability. The results of the Core Policy scenarios provide useful insights as to how those needs might best be met.

+ Acquisition of **cost-effective energy efficiency** plays an important role in limiting the new investments needed to meet regional peak needs across all scenarios. By 2050, the implied peak load reduction associated with the portfolio of cost-effective energy efficiency is 8,400 MW—enough to offset 9,600 MW of new investments in firm resource capacity.
+ New **demand response** programs offer an enticing low-cost prospect for meeting regional peak needs—roughly 1,500 MW of demand response resources are selected in all of the Core Policy scenarios. Continuing to explore new potential DR programs that offer low-cost means to avoid new investments in generation resources is prudent. However, ultimately, the size of the DR

market is likely limited, and it is unlikely that demand-side programs alone will be capable of meeting all future capacity needs within the region.

+ New investments in **renewable generation**, while valuable for energy, contribute little to meeting regional peak needs. The capacity value of a resource depends on the ability of a resource to produce on demand during peak periods; the intermittence and variability of both wind and solar PV mean that they cannot contribute significantly to meeting regional peak needs. Table 5-2 summarizes the contribution of intermittent renewables to the regional capacity need based on their effective load carrying capability (ELCC). While the marginal contribution of wind and solar PV varies by scenario, the overall average ELCC of the wind and solar portfolio across all scenarios is consistently between 14%-17%--that is, each 1,000 MW of wind and solar resources installed contribute approximately 150 MW towards meeting regional peak needs.

Table 5-2. Summary of installed intermittent renewables (wind and solar PV) in 2050

Scenario		Installed Capacity (MW)	ELCC (MW)	ELCC (%)
Reference		11,570	1,892	16%
Carbon Cap	40% Reduction	11,754	1,930	16%
	60% Reduction	13,845	2,386	17%
	80% Reduction	17,783	2,895	16%
Carbon Tax	Gov Tax	15,359	2,663	17%
	Leg Tax	15,686	2,709	17%
High RPS	30% RPS	16,425	2,804	17%
	40% RPS	23,376	3,482	15%
	50% RPS	29,194	4,190	14%
No New Gas		12,544	2,096	17%

+ Investments in **energy storage** to meet capacity needs within the region appear to be a very high-cost option for meeting regional capacity needs. The only scenario in which new energy storage is selected as part of the optimal portfolio is in the No New Gas case, which explicitly prohibits new natural gas generation. The cost premium for energy storage is one of the major drivers for the relative cost increase in this scenario.

+ In contrast, **new investments in gas generation** capacity provide the lowest-cost means of meeting regional peak needs once cost-effective EE and DR resources have been fully deployed. Aside from the No New Gas case, which prohibits new gas generation explicitly, all Core Policy scenarios include some level of new investment in gas generation to meet regional peak needs (see Table 5-3). The inclusion of 5,100 MW of new gas CTs in the 80% reduction case suggests a role for new natural gas investments even in a low-carbon grid. The reason for this rests on the distinction between *capacity* and *energy*: the large amount of new gas capacity selected in these cases is chosen with the expectation that it will operate very infrequently—only when needed for reliability—and so will have a very small absolute impact on the regional greenhouse gas footprint.

Table 5-3. Cumulative investments in new gas CTs through 2050

Scenario		Installed Capacity (MW)
Reference		7,153
Carbon Cap	40% Reduction	6,814
	60% Reduction	6,258
	80% Reduction	5,147
Carbon Tax	Gov Tax	5,861
	Leg Tax	5,814
High RPS	30% RPS	6,040
	40% RPS	5,361
	50% RPS	5,899
No New Gas		—

5.4 Wholesale Market Price Impacts

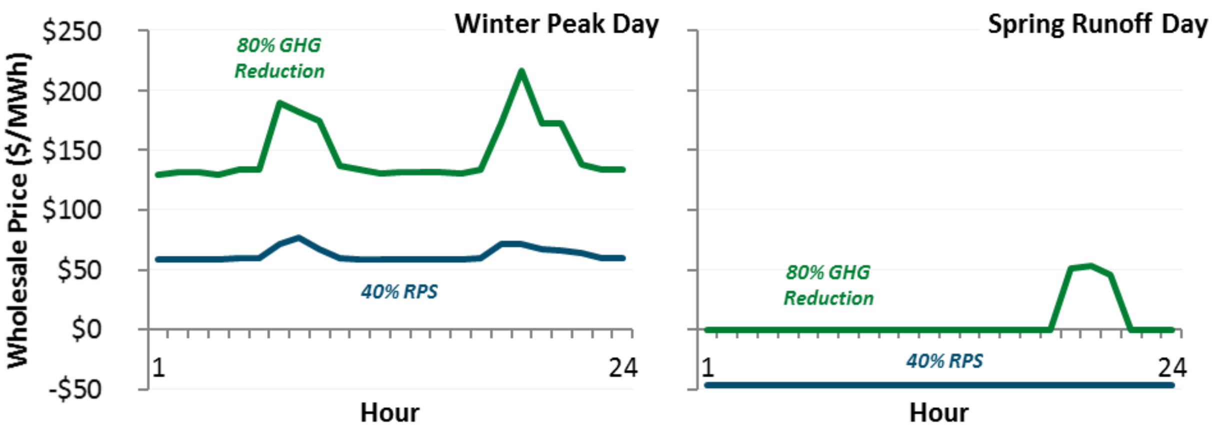
While producing long-term market price forecasts is not RESOLVE's intended primary purpose, its outputs do provide useful indications as to the directional impacts of different policies on wholesale energy markets based on each scenario's marginal cost of generation.

The impacts of the various policies considered in this study on wholesale markets vary dramatically:

- **Carbon Cap** (and **Carbon Tax**) policies will result in an increase in wholesale market prices. Because an explicit cost of carbon is internalized by generators, when gas or coal is on the margin, the marginal cost of generation increases. When renewable generators are on the margin, the wholesale market price converges to zero—the marginal cost of generation for wind and solar PV. These increases in wholesale price reflect the fact that the short-term market has internalized the cost of carbon, enabling the wholesale market to contribute to the efficient achievement of carbon reductions within the region.
- **High RPS** policies will suppress wholesale market prices relative to the Reference Case. At higher penetrations, as renewable curtailment becomes prevalent and curtailment becomes significant, periods when renewable generation are on the margin are characterized by negative market prices because parties are willing to pay up to the value of the lost REC, or the opportunity cost of curtailing renewables.
- The **No New Gas** policy has a relatively limited impact on market prices. While this policy has a dramatic impact on what investments are possible, it does not have a direct impact on how the system operates or the relative costs of operating different types of resources.

To illustrate how these drivers would propagate through to wholesale markets, consider two example operating days: (1) a peak load winter day, and (2) a spring runoff day; hourly market prices from RESOLVE for each of these two types of operating days are shown in Figure 5-4 to compare the wholesale market price impact of an RPS policy (40% RPS) with a carbon pricing policy (80% Reduction).

Figure 5-4. Representative hourly market price shapes for a winter peak load day and a spring runoff day



+ On a peak load day, gas generation is the marginal resource throughout the day in both scenarios, and its marginal cost sets the wholesale market price. In the 40% RPS scenario, its marginal cost includes fuel and variable O&M; in the 80% Reduction scenario, its marginal cost includes fuel, variable O&M, and the cost of procuring a carbon allowance, resulting in a higher wholesale market price (and a stronger market signal for the value of additional zero-carbon generation).

+ On a spring runoff day, both systems are in oversupply throughout most of the day, resulting in renewable curtailment during most hours. In the 40% RPS scenario, renewable curtailment results in negative wholesale market prices—because the foregone RECs must be replaced to comply with the RPS production quota, utilities are willing to pay up to the cost of procuring a REC to deliver renewables to a system that is already saturated with zero carbon power. In contrast, in the 80% Reduction scenario, there is no distortionary incentive to deliver renewable generation to a system already saturated with zero-carbon resources; the wholesale price converges to zero, the marginal cost of variable resources.

It is crucial to note, in describing the relative wholesale pricing among policies, that the relative wholesale prices observed in each scenario do not translate to the same effects on retail electricity prices within the region. In fact, the GHG Reduction scenarios yield the lowest retail rates and achieve greater emissions benefits than the other cases.

Table 5-4 summarizes the annual average market prices observed in each of the Core Policy scenarios.

Table 5-4. 2050 annual average Mid-Columbia market prices by scenario

Scenario		HLH	LLH	Average
Reference		$47	$43	$46
Carbon Cap	40% Reduction	$59	$56	$58
	60% Reduction	$61	$57	$60
	80% Reduction	$74	$70	$73
Carbon Tax	Gov Tax	$64	$60	$63
	Leg Tax	$66	$62	$64
High RPS	30% RPS	$42	$39	$41
	40% RPS	$35	$32	$34
	50% RPS	$20	$19	$20
No New Gas		$46	$45	$45

The different impacts on wholesale market prices have direct implications for utilities within the region. In particular:

+ The higher wholesale market prices in the Carbon Cap and Carbon Tax scenarios provide a direct market signal to encourage investment in new low- and zero-carbon generation and energy efficiency. The impact of these policies on wholesale market prices, and the apparent increase in value for low- and zero-carbon resources, is the mechanism through which these policies promote the least-cost portfolio to meet a carbon goal.
+ The higher wholesale market prices observed in the Carbon Cap and Carbon Tax scenarios provide a stronger signal for continued maintenance and reinvestment in existing hydro and nuclear resources—a major source of zero-carbon power within the region. The lower prices observed in

a High RPS scenario are more likely to create a challenging economic environment for these existing resources and could lead to their retirement—a step backwards for a region seeking to reduce greenhouse gas emissions.

6 Sensitivity Analysis

6.1 No Revenue Recycling

6.1.1 OVERVIEW

One of the key policy decisions in the design of any policy that applies a price to carbon is the use of revenues raised by the program. The disposition of program revenues—whether raised through a tax on carbon or through the purchase of allowances—impacts the bottom line impact of the program on the costs borne by electric ratepayers. On one end of the spectrum, revenues raised may be "recycled" into the sectors that are responsible for emissions—for instance, as a rebate to customers in the electric sector or by buying down the costs of investments made to decarbonize the electric sector. At the other end of the spectrum, carbon revenues may be put to other uses within the economy outside the electric sector—for instance, in funding schools or public works.

Among jurisdictions that have implemented or explored carbon pricing policies, the recycling of revenues collected from the electric sector to ratepayers has been a common feature to help contain the costs of the policy:

+ In the **Western Climate Initiative (WCI)** in California, the California Air Resources Board freely allocates a share of allowances to the state's electric distribution utilities, who then auction those allowances to the market. The revenues generated by this process are rebated to residential and commercial customers in the form of a "carbon dividend" each November, helping to offset some of the incremental costs associated with California's other clean energy policies.
+ Under the **Climate Leadership Plan (CLP)**, Alberta has imposed a carbon tax on its economy. The revenues raised by this program are intended to be split between direct rebates to households

and businesses and providing funding to support decarbonization efforts through supporting the phase-out of coal generation and incremental investments in renewables and energy efficiency.

+ As the state of New York has begun to explore the impacts of carbon pricing on its markets, the New York Independent System Operator (NYISO) and the Department of Public Service (DPS) commissioned a study[36] to examine the impacts of carbon pricing on wholesale markets and costs in New York. The study assumes that revenues raised through a carbon pricing mechanism would be returned to customers, although the exact mechanism has not been determined.

This analysis assumes revenue neutrality of carbon pricing scenarios within the electric sector—that is, revenues raised through carbon pricing are returned to electric ratepayers to offset the costs of purchasing allowances (or paying a carbon tax). In this respect, the incremental cost of each scenario reflects the cost of new investments in low-carbon generation and operating costs of dispatching lower-carbon fuels—the societal cost of achieving emissions reductions within the electric sector—but do not include additional costs for the revenue collected through the emissions for which the electric sector is responsible. In recognition of the possibility that a carbon pricing policy could be designed in such a way that revenues are instead diverted to other purposes within the economy, this sensitivity quantifies the additional costs to electric ratepayers should these revenues be diverted to other sectors. The scope of incremental costs included in the base case and in the "No Revenue Recycling" sensitivity is shown in Table 6-1.

Table 6-1. Categories of cost captured in No Revenue Recycling sensitivity

Cost Category	Base Case	No Revenue Recycling
Incremental fixed costs of low-carbon investments	✓	✓
Incremental operating costs of low-carbon fuels	✓	✓

[36] *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals* (Brattle Group, 2017), available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf

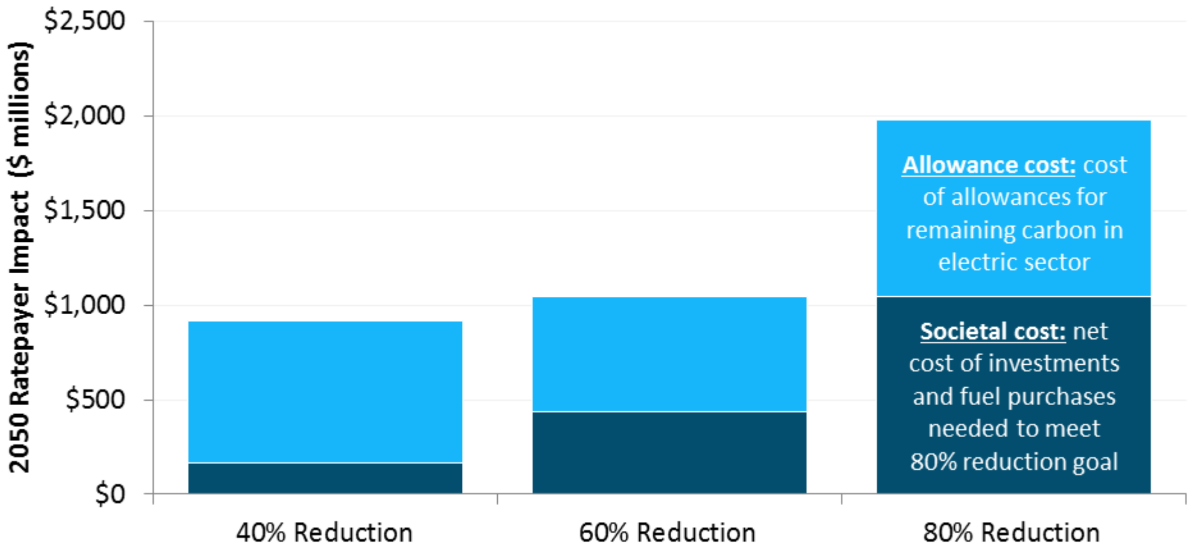
Cost Category	Base Case	No Revenue Recycling
Carbon price applied to all remaining emissions in electricity	✓	✓
Carbon revenues "recycled" to electric ratepayers	✓	✗

This sensitivity is explored for both the Carbon Cap and Carbon Tax scenarios. In the Carbon Tax scenarios, the price on carbon is an exogenous input to the model, and so its effect on electric sector costs is relatively simple to evaluate. In the Carbon Cap cases, no exogenous price is implied; however, RESOLVE determines a "shadow price" on the carbon constraint—the marginal cost of greenhouse gas emissions reductions needed to reach a specified level of reductions—and this is assumed to be the price at which the market for allowances clears for the sake of this exercise.

6.1.2 RESULTS

In this sensitivity, the resource portfolios and emissions reductions associated with carbon pricing scenarios do not change—the incremental cost is adjusted to reflect a design difference in the disposition of carbon revenues. The impact of the choice to use carbon allowance/tax revenues for purposes other than reducing costs to ratepayers is shown in Figure 6-1.

Figure 6-1. Impact of "No Revenue Recycling" sensitivity on Carbon Cap incremental costs



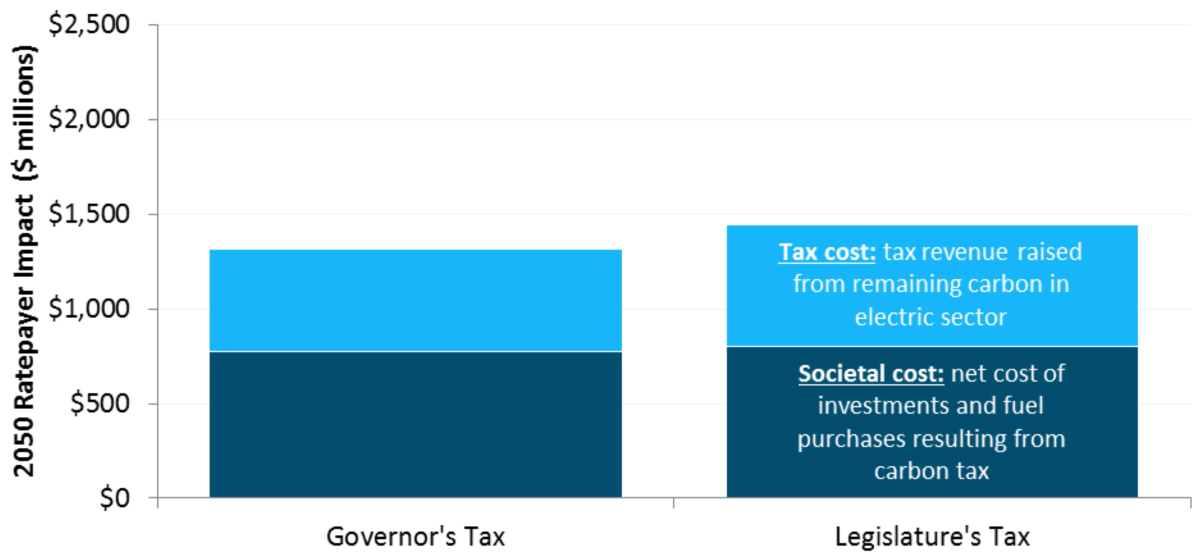
The incremental cost to electric ratepayers of not recycling revenues from a carbon pricing scheme depends on two factors: (1) the amount of greenhouse gas emission for which the electric sector is responsible, and (2) the carbon price applied to those emissions. These two factors have difference levels of significance in the scenarios studied:

+ In the **40% Reduction** case, the assumed cost of allowances is relatively low ($37/tonne in 2050), but the amount of emissions in the electric sector is high (20 million metric tons)—as a result, the additional cost borne by electric ratepayers increases by $752 million per year in 2050. This is a large increase in cost compared to the societal cost of emissions reductions needed to reach this level—$163 million per year.
+ In the **60% Reduction** case, the assumed cost of allowance remains relatively low ($45/tonne in 2050), but the quantity of emissions to which this price is applied is smaller (14 million metric tons). As a result, the additional costs borne by electric ratepayers increases by a smaller amount--$613 million per year. Nonetheless, this additional cost remains large in comparison to the societal costs of achieving this level of emissions reductions--$434 million per year.

+ In the **80% Reduction** case, the assumed cost of allowances increases significantly to $139/tonne, reflecting the higher marginal cost of deep decarbonization within the electric sector. Thus, despite having the lowest overall level of emissions (7 million metric tons), the additional costs borne by ratepayers in this scenario is large ($935 million per year). This effectively roughly doubles the cost to the electric sector of meeting the 80% reduction goal, as the societal costs of meeting that emissions reduction target were $1 billion per year.

A decision not to recycle tax revenues back to the electric sector under a carbon tax scheme has a similar impact on the costs of those policies to the electric sector. Figure 6-2 shows the additional costs borne by ratepayers in the two Carbon Tax scenarios should the tax revenues raised from the electric sector be put to other uses within the economy.

Figure 6-2. Impact of "No Revenue Recycling" sensitivity on Carbon Tax incremental costs



6.1.3 IMPLICATIONS

Economists have long touted carbon pricing policies as a mechanism to incent changes to reduce carbon throughout the economy; this type of policy will also result in a carbon fund. The creation of such a carbon fund is secondary to the purpose of carbon pricing—to promote efficient decarbonization of the economy—and its disposition should be carefully considered with respect to distributional impacts. This sensitivity highlights two potential bookends related to the disposition of carbon revenues raised from the electric sector—one in which those revenues are returned to electric ratepayers, and second in which they are diverted for other purposes within the economy. With revenue recycling, the costs incurred by electric ratepayers reflect the societal costs of reducing carbon within the electricity sector: the incremental costs reflect only the increased costs of investments in and operations of additional low- and zero-carbon resources; revenue recycling mitigates the impact of the carbon pricing policy on ratepayers while ensuring that they respond to the appropriate marginal price signals in investment and operational decisions. Without revenue recycling, electric ratepayers, in addition to the societal costs additional low-carbon generation, bear the full additional costs attributed to the remaining greenhouse gas emissions produced by the electric sector.

6.2 Loss of Existing Carbon-Free Resource

6.2.1 OVERVIEW

Historically, the Northwest's existing carbon-free resources—31,500 MW of hydroelectric generation and 1,200 MW of nuclear—have played an important role in meeting regional energy needs, providing customers with a significant amount of low-cost power. This study assumes that these resources remain in service and continue to operate at the same capacity as they do today throughout the study's analysis horizon. The continued operations of the existing carbon-free resource fleet is not a predetermined outcome, as many of these plants will face relicensing decisions before 2050, and the current environment of low wholesale market prices can make it difficult to justify reinvestment in maintenance and new capital expenditures needed to keep plants in operations.

This sensitivity explores how the retirement of a portion of this fleet would impact the cost of meeting the region's greenhouse gas goals. This sensitivity assumes the retirement of 1,000 aMW of hydroelectric generation as well as the full capacity of the Columbia Generating Station—a total of roughly 2,000 aMW of carbon-free resources. In each portfolio, the incremental operating and investment costs to replace this assumed retiring capacity provides a measure of the value of those resources under different policy mechanisms. Comparing the implied value of this existing carbon-free resource under the Reference Case and the 80% Reduction Case thereby provides a contrasting measure of the long-term market value in a world without a policy focused on greenhouse gases and the higher value that these resources provide in the context of meeting a regional greenhouse gas goal.

6.2.2 RESULTS

Replacing 2,000 aMW of nuclear and hydro resources—or 3,400 MW of installed capacity—requires the replacement of both the **energy**—the total amount of generation produced over the course of the year—and the **capacity**—the ability to produce power over sustained periods when needed for system reliability—associated with those resources. RESOLVE optimizes the both the investments and the dispatch of the electric system to identify the optimal portfolio of replacement resources under both the Reference Case and the 80% Reduction case. Figure 6-3 shows the new investments selected to replace the retiring capacity; Figure 6-4 shows the impact on the region's annual generation mix.

Figure 6-3. New investments to replace loss of 2,000 aMW of hydro and nuclear resources

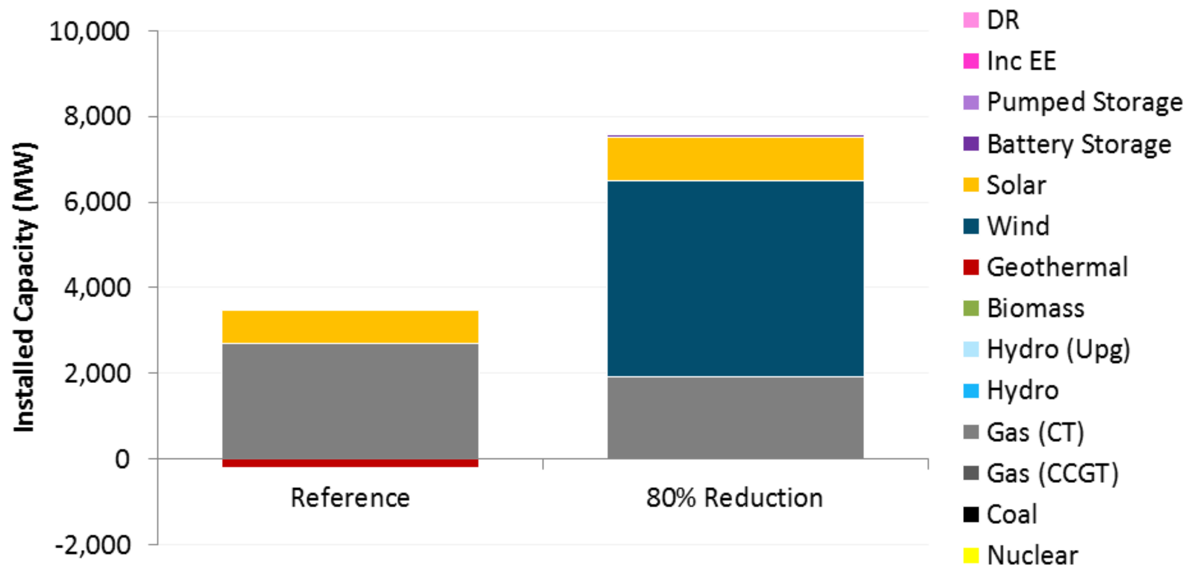
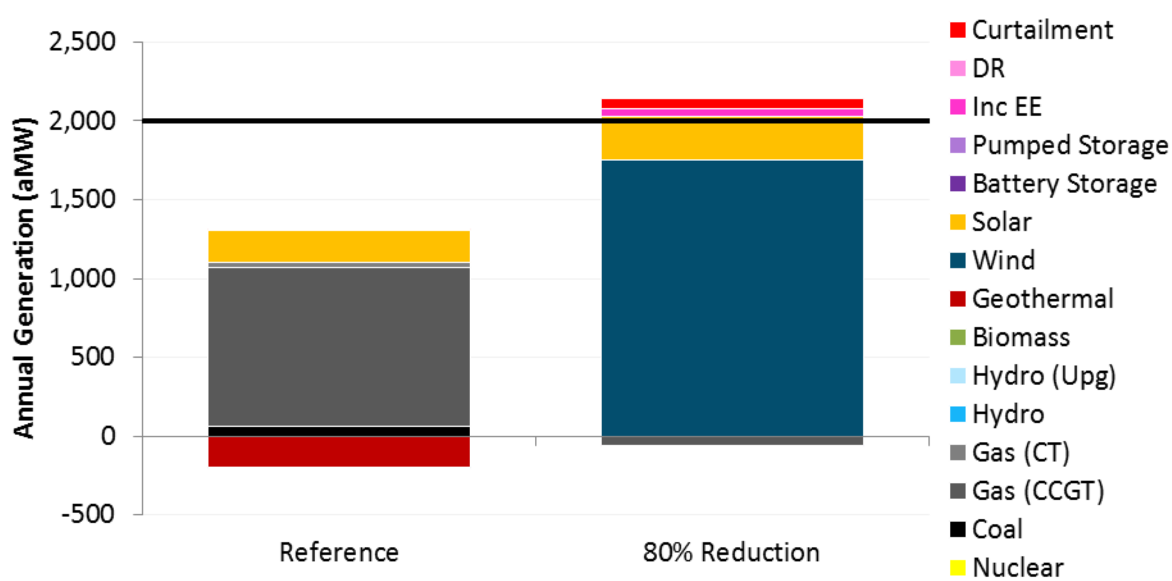


Figure 6-4. Generation mix of resources added to replace 2,000 aMW



The portfolio of resources selected to replace the retiring capacity varies between the scenarios:

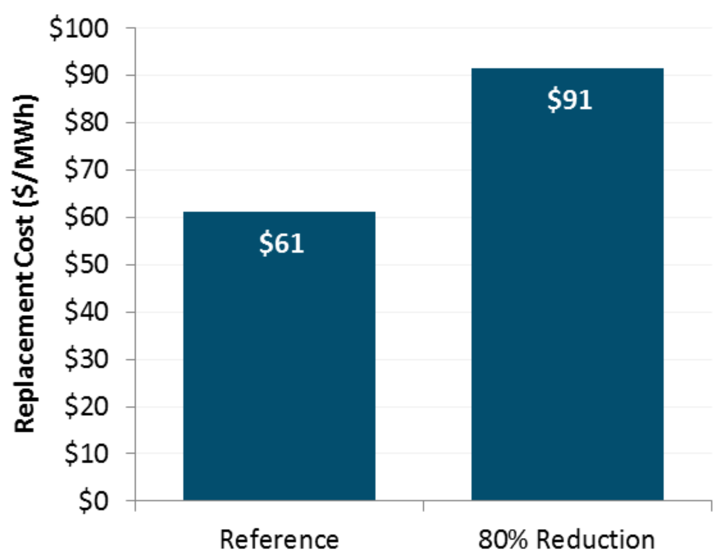
- In the **Reference Case**, the retiring capacity is replaced by new natural gas capacity. The retirement of these resources also results in a slight shift in the composition of the optimal renewable portfolio towards solar PV and away from geothermal—a result of the impact of the retirement of existing hydro and nuclear on the relative value of solar and geothermal. In this scenario, because there is no formal requirement to replace the retiring generation with carbon-free resources, the replacement energy (shown in Figure 6-4) is a mix of increased gas dispatch within the region and increased reliance on net imports from other parts of the Western Interconnection—resulting in an increase in the emissions associated with the Reference Case by 5 million metric tons in 2050.
- In the **80% Reduction** scenario, the new investments come in two types. First, because the energy produced by retiring hydroelectric and nuclear resources must be replaced one-for-one with carbon free generation, significant investments in wind and solar are needed. Because of their comparatively lower capacity factors, 5,600 MW of wind and solar resources are needed to produce the 2,000 aMW of generation to replace the retiring resources. At the same time, these investments in wind and solar do little to meet the region's capacity needs to meet peak demand. Thus, in addition to major investments in new renewables, an additional 1,900 MW of new combustion turbines are selected to ensure that the region's electric fleet provides a comparable level of reliability. Thus, in total, 7,500 MW of new generation capacity is added in this scenario to replace the assumed retirements of 3,400 MW of hydroelectric and nuclear generation.

The implications on cost to the electric sector, summarized in Table 6-2, of the existing resource retirement also vary between the scenarios. In the Reference Case, the cost to replace the retiring capacity—predominantly with natural gas—is $1.1 billion per year. In the 80% Reduction case, the cost to replace retiring capacity with zero carbon generation is $1.6 billion per year—more than the total cost to achieve the 80% reduction target should those resources remain in service. Figure 6-5 shows the replacement costs, unitized per MWh of lost production, under the Reference and 80% Reduction scenarios.

Table 6-2. Cost impacts of 2,000 aMW existing zero-carbon resource retirement

	Reference Case	80% Reduction Case
Incremental cost with all existing resources in service ($MM/yr)	—	$1,046
Incremental cost with 2,000 aMW existing resource retirement ($MM/yr)	$1,071	$2,652
Replacement cost for 2,000 aMW of retiring resources ($MM/yr)	**+$1,071**	**+$1,606**

Figure 6-5. Replacement cost for retirement of 2,000 aMW of existing hydro and nuclear generation



6.2.3 IMPLICATIONS

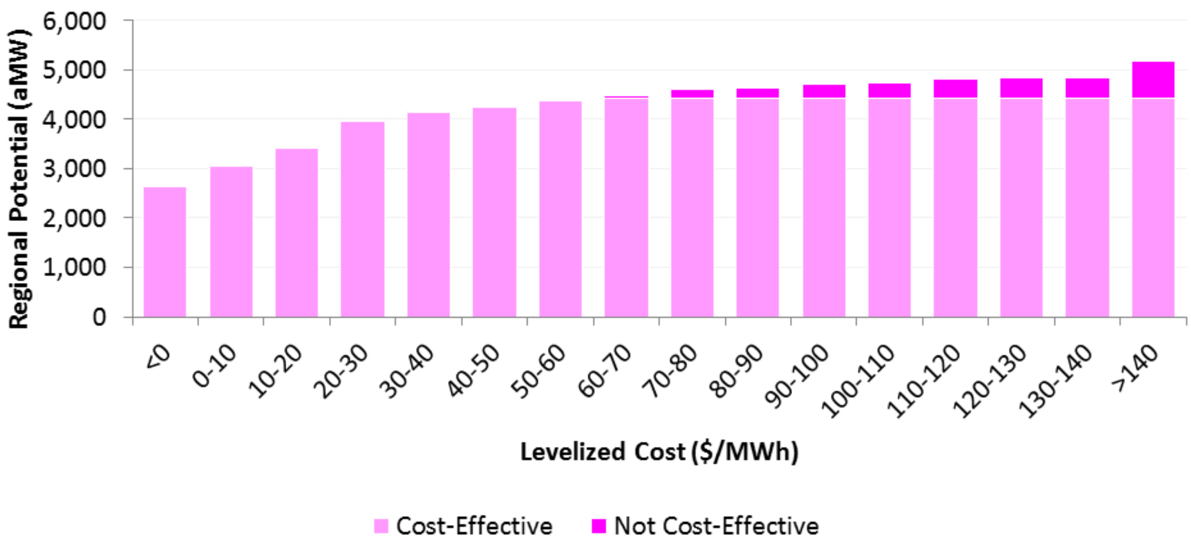
The cost to replace the energy and capacity provided by existing zero-carbon resources provides a measure of their value under the policy priorities implied in each scenario. Under the Reference Case, with no formal or organized greenhouse gas policy, the replacement cost is essentially set by a natural gas benchmark. However, this perspective ignores the value of the zero-carbon attributes of the existing hydro and nuclear resources—an attribute highlighted in the 80% Reduction scenario, which shows a considerably higher value for existing carbon-free resources. What this contrast highlights is the idea that current wholesale market prices undervalue carbon-free resources in the context of meeting a regional greenhouse gas goal; one way to address this discrepancy is through carbon pricing policy that will inherently reward carbon-free resources for their value in the wholesale market.

6.3 High Energy Efficiency Potential

6.3.1 OVERVIEW

In this study, incremental energy efficiency—efficiency beyond that which is identified by the NWPCC's Seventh Power Plan as cost-effective for the region—is treated as a resource that is available for selection in each portfolio optimization in order to highlight how different policies provide different market signals to encourage (or discourage) further adoption of energy efficiency. In the base case assumptions, the supply curve for incremental energy efficiency is developed based on data provided by the NWPCC to characterize the energy efficiency measures that were found to be beyond its cost-effectiveness threshold. However, as shown in Figure 6-7, the amount of efficiency potential that exists in the supply curve beyond the current cost-effectiveness threshold is limited—5,200 aMW of regional achievable potential by 2035, compared to the 4,400 aMW found to be cost-effective on that time frame.

Figure 6-6. NWPCC energy efficiency supply curve showing cost-effective resources

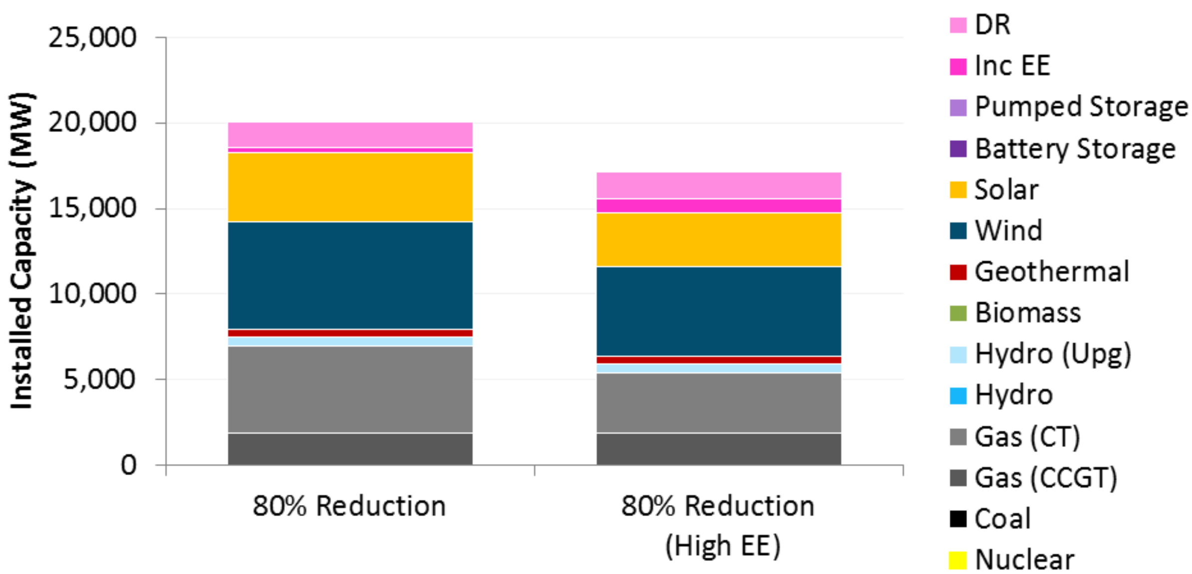


This sensitivity tests the impact of including an additional bundle of 1,000 aMW of incremental "high-cost" energy efficiency, priced at $110/MWh, in the supply curve to highlight how the different policies considered in this study impact the cost-effectiveness criteria for efficiency.

6.3.2 RESULTS

Under both the Reference Case and the 50% RPS Case, the addition of incremental high-cost efficiency to the supply curve has no impact on the optimal portfolio. In the 80% Reduction scenario, allowing additional high-cost efficiency to be selected results in a shift in the composition of the optimal portfolio—away from new gas and renewables and towards energy efficiency (shown in Figure 6-7). In this case, an additional 600 aMW of energy efficiency is selected, reducing the amount of wind (1,000 MW) and solar (1,000 MW) needed to meet greenhouse gas reduction goals while also displacing 1,600 MW of new natural gas combustion turbines—no longer needed due to a reduction in peak demand. The substitution of additional energy efficiency for renewables reduces the cost of meeting the 80% reduction goal by $140 million per year in 2050.

Figure 6-7. Cumulative new generation capacity by 2050, High EE sensitivity



6.3.3 IMPLICATIONS

This sensitivity suggests highlights the increase in value for efficiency under a carbon-constrained world: whereas no additional efficiency is selected in the Reference Case, a large amount is selected in the 80% Reduction scenario. Under the 80% Reduction case, the paradigm for energy efficiency cost-effectiveness and avoided costs shifts from one focused on the market value for energy and capacity value—which today creates a challenging environment to justify spending on energy efficiency programs because it the current market does not capture the value of carbon—to one in which the value of efficiency is the based on a carbon-free replacement cost. In other words, energy efficiency programs deemed not cost-effective based on today's market prices may have a crucial role to play as a least-cost component of a low carbon portfolio.

This observation points towards the need to continue research and development in efficiency even during a period in which low gas prices make it difficult to justify expansive energy efficiency programs. Understanding what types of measures may be available at costs beyond today's cost-effectiveness thresholds—and continuing to invest in development of emerging efficiency technologies—will help prepare the region to continue its historical focus on conservation, but with intensified goals as part of a carbon-focused policy.

The selection of increasing quantities of energy efficiency under the Carbon Cap scenarios also highlights the direct linkage between energy efficiency cost-effectiveness and energy policy. Under current policy, the avoided costs used to measure cost-effectiveness reflect the market value of energy and capacity but do not capture any value for the carbon reductions provided by energy efficiency. Under a policy that introduces an explicit price on carbon, the avoided cost of energy efficiency will automatically capture the perceived carbon-free value of the resource. This linkage between policy and the processes used to evaluate energy efficiency underscores the importance of designing policy that encourages the types of resource investments needed to meet long-term greenhouse gas reduction goals.

6.4 High Electric Vehicle Adoption

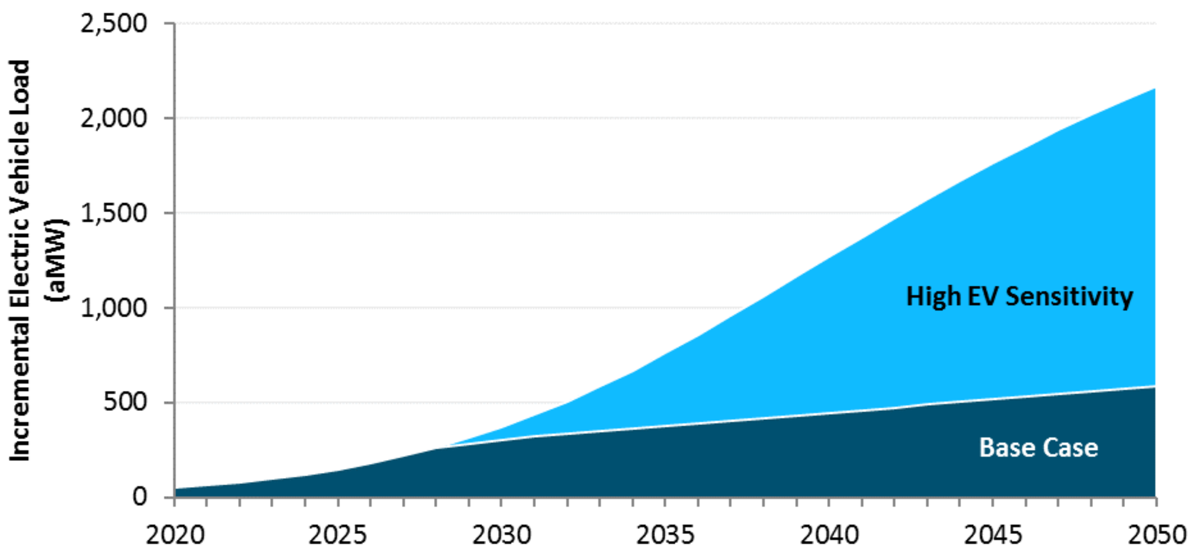
6.4.1 OVERVIEW

Most of the analysis conducted in this study focuses on the electric sector, exploring how it can most effectively contribute to the decarbonization of the economy. As discussed in Section 1.2, the successful achievement of economy-wide carbon goals will require cross-sectoral approaches. This sensitivity examines the potential role of transportation electrification as part of such a strategy, seeking to answer the following questions:

+ How could the electric sector supply low-carbon power to meet the needs of an electrified transportation end use, and at what cost?
+ What is the total resource cost of transportation electrification, and how does its cost compare to other measures examined within this study?

In this sensitivity, the assumed adoption of light-duty electric vehicles is increased from 1.5 million by 2050 (included in the Core Policy scenario analysis) to 5 million by 2050. As shown in Figure 6-8, this results in an increase in regional load of 2,200 aMW in the High EV sensitivity.

Figure 6-8. Transportation electrification loads in the High EV sensitivity

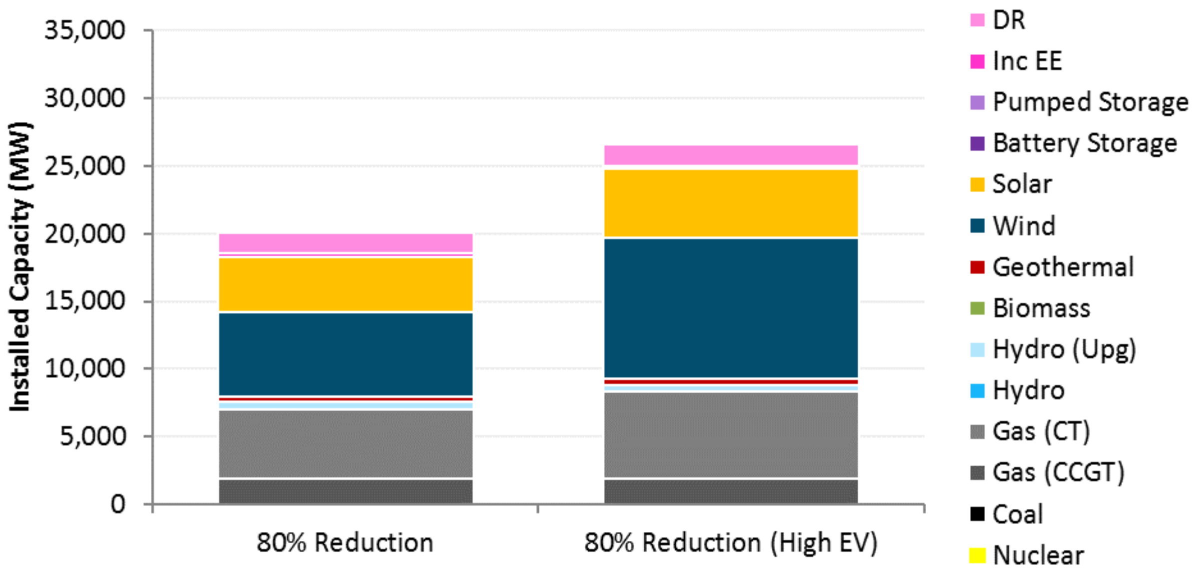


6.4.2 RESULTS

Figure 6-9 highlights the new investments selected to meet the incremental new EV load under the High EV sensitivity. In addition to the resources selected to meet the 80% reduction goal in the Core Policy scenarios, the High EV case includes an additional 4,200 MW of wind, 1,000 MW of solar PV, and 1,300

MW of new natural gas capacity. The incremental renewables provide the carbon free energy to supply the new loads while maintaining a low level of emissions, whereas the additional gas generation ensures sufficient capacity to meet slightly higher peak demands with new transportation electrification loads.

Figure 6-9. Cumulative new generation capacity by 2050, High EV sensitivity



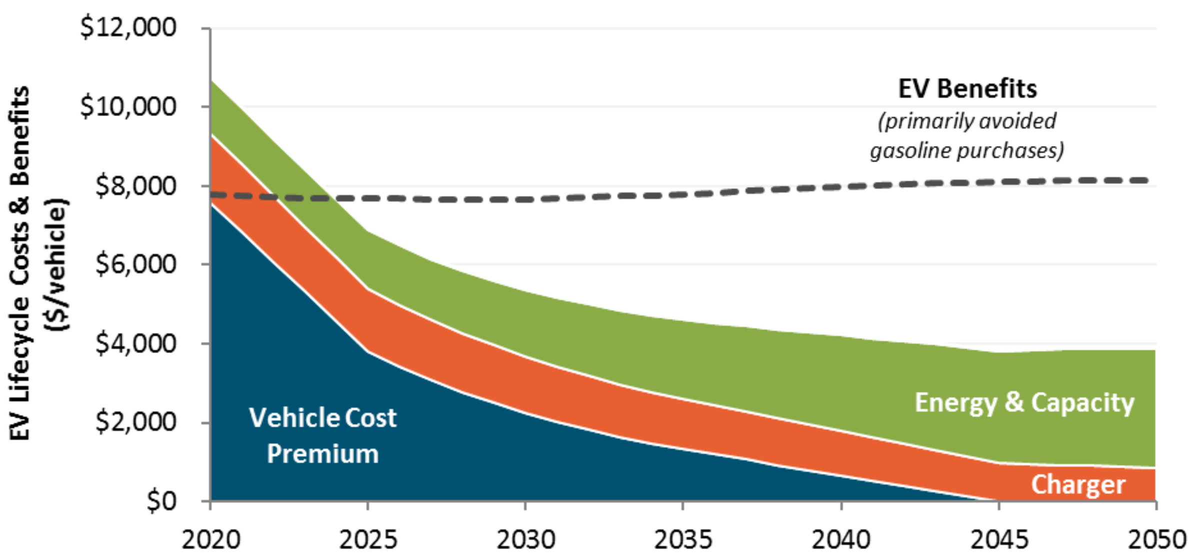
The incremental cost to the electric sector—the cost to supply the necessary carbon-free energy and capacity to facilitate this level of EV charging, is approximately $1,450 million per year, or $104/MWh of new additional electric load. This cost to supply carbon-free energy and capacity to meet new load is combined with estimates of other costs and benefits of electric vehicles to offer a societal perspective on the cost-effectiveness of electric vehicles into the future. The other categories of costs and benefits considered include:

+ **Vehicle cost premium:** the incremental cost of purchasing an electric vehicle, relative to a comparable gasoline vehicle.
+ **Charger cost:** the cost to install charging infrastructure to allow charging (at home or remotely);

+ **Avoided gasoline purchases:** the reduction in purchases of gasoline to fuel a gasoline vehicle; and
+ **Avoided operations and maintenance:** the reduction in cost of upkeep for an electric vehicle relative to a gasoline vehicle.

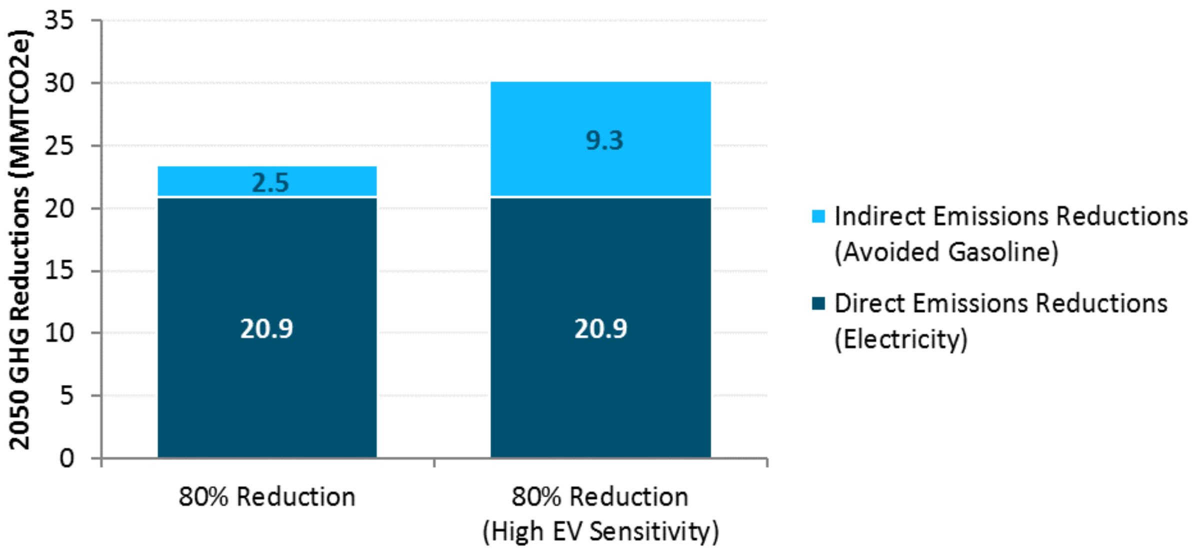
Each category of costs and benefits are estimated over the lifetime of a new vehicle purchase to provide the cost-benefit assessment of electric vehicles shown in Figure 6-10. Largely due to anticipated cost reductions for electric vehicles, the benefits of purchasing a new electric vehicle are expected to surpass the costs by 2025. As the electric vehicle cost approaches parity with gasoline vehicles, the remaining costs of EV ownership—charging infrastructure and the supply of electricity to charge the vehicle—are much smaller than the avoided cost of gasoline.

Figure 6-10. Snapshots of electric vehicle cost-effectiveness over time



Not only do electric vehicles thus appear cost-effective from a societal perspective in the long-run, but they provide a direct mechanism to reduce carbon in the transportation sector. Figure 6-11 shows the impact of the High Electrification sensitivity on economy-wide emissions reductions—through the electrification of transportation, the electric sector facilitates emissions reductions of an additional seven million metric tons. This result thus suggests that electric vehicles provide long-run benefits from both an economic and greenhouse gas perspective.

Figure 6-11. Impact of High EV sensitivity on economy-wide emissions in 2050



6.4.3 IMPLICATIONS

This sensitivity highlights the potential beneficial role of transportation electrification as a component of a broader decarbonization strategy as a measure that, in the long-term, both reduces societal costs and reduces greenhouse gas emissions—a measure with a negative carbon abatement cost. This perspective on electric vehicles as a cost-saving emissions reduction strategy is consistent with findings in a number of prior studies.

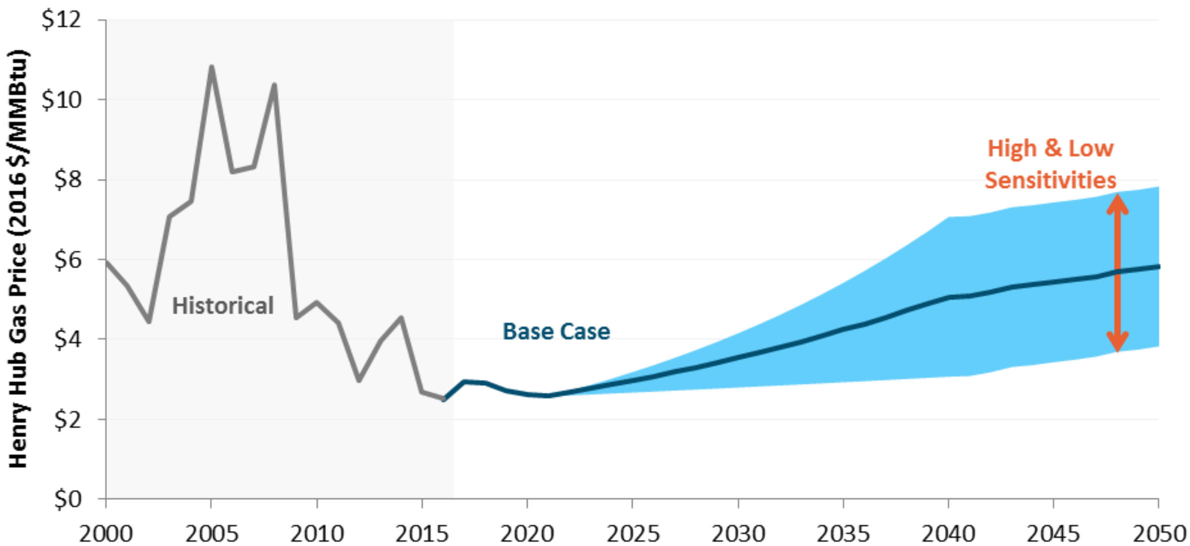
But while the analysis suggests that vehicle electrification has a significant role to play in economy-wide decarbonization, there are a number of challenges to achieving such high levels of transportation electrification that decision-makers must consider. One such outstanding question that will require careful consideration is what role utilities will play in the process of incentivizing, facilitating, and serving new electric loads as they come onto the system. Policies designed to encourage electrification must consider the role that utilities will play as the suppliers of low-carbon primary energy as significant new loads begin to materialize. How to ensure that existing ratepayers are not unduly harmed as fossil end uses migrate into the electric sector will be a pressing question for utilities and decision-makers alike to address.

6.5 High and Low Gas Prices

6.5.1 OVERVIEW

The future price of natural gas is a major potential source of uncertainty in the cost of power procurement, as well as in the relative cost of various decarbonization measures in the electric sector. Sensitivities on future gas price test the impacts of +$2/MMBtu and -$2/MMBtu increments in 2050. The range of gas price sensitivities is shown in Figure 6-12.

Figure 6-12. Henry Hub forecasts for high and low gas price sensitivities



6.5.2 RESULTS

Figure 6-13 and Figure 6-14 compare the 2050 cost and emissions impacts for each scenario under the Low Gas Price and High Gas Price sensitivities with the Base Case assumptions, respectively. Under both the Low Gas Price and High Gas Price sensitivity, general directional relationships among the scenarios are consistent with findings under the base case assumptions.

Figure 6-13. Impact of Low Gas Price sensitivity on scenario cost and emissions impacts in 2050

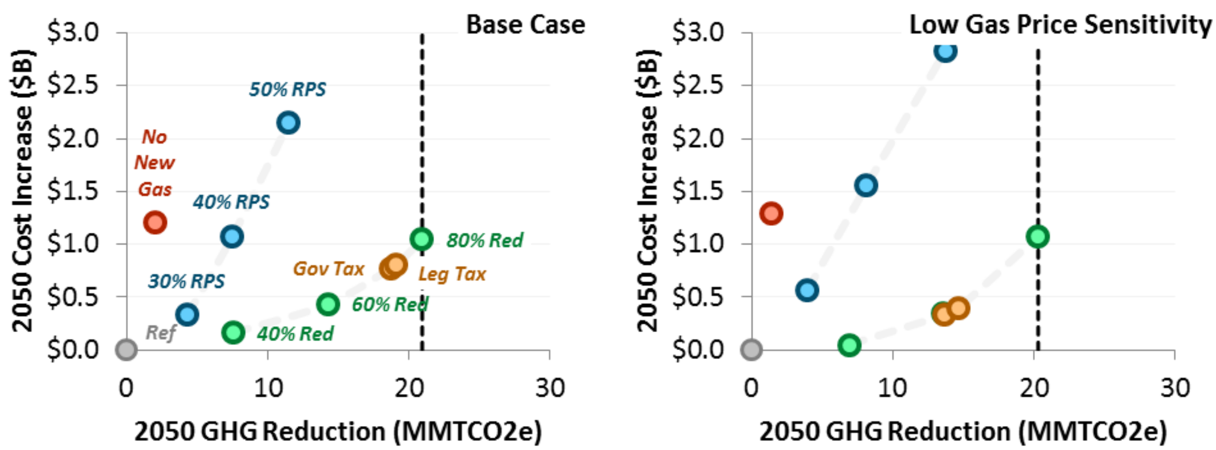
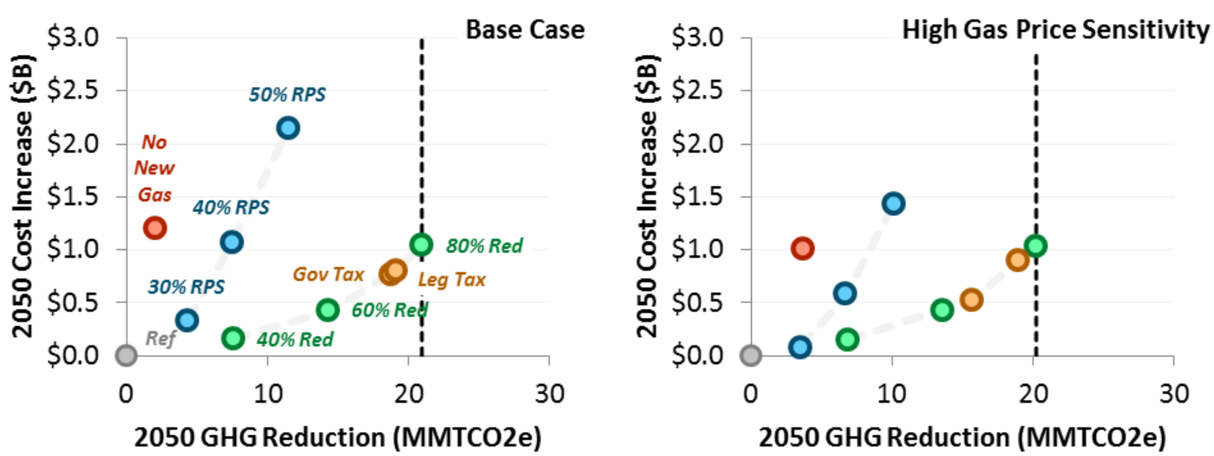


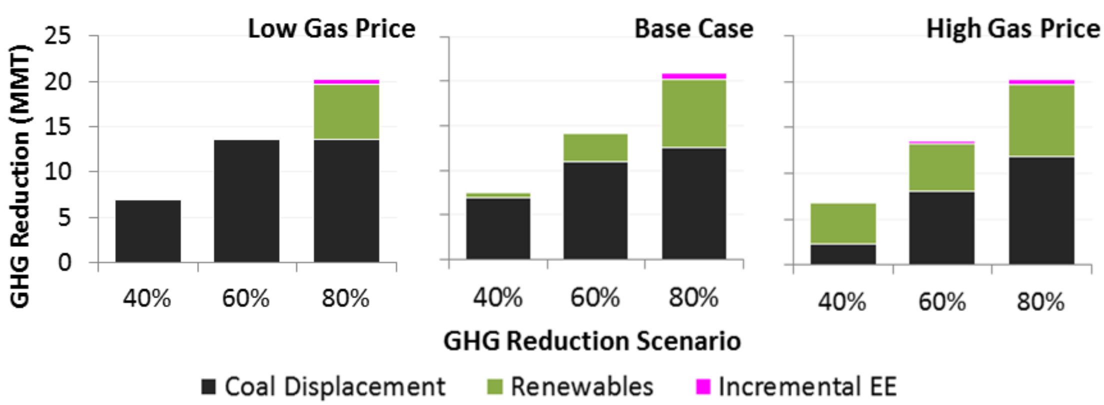
Figure 6-14. Impact of High Gas Price sensitivity on scenario cost and emissions impacts in 2050



+ The scenarios that exhibit the most sensitivity to gas prices are the High RPS. The most significant impact of the gas price sensitivity is its impact on the relative cost-effectiveness of incremental renewable generation as manifest in the High RPS scenarios. A low gas price reduces wholesale market prices and increases the net cost of new investments in renewables; in the Low Gas Price sensitivity, the 2050 cost increase associated with the 50% RPS scenario increases from $2.1 billion per year to $2.8 billion per year.

+ In comparison, the cost associated with Carbon Cap scenarios do not show a significant sensitivity to future natural gas prices. There is a shift in the relative cost-effectiveness of coal displacement and renewable investment as carbon abatement strategies: higher gas prices make coal-to-gas displacement more costly while at the same time reducing the net cost of renewable investment; the opposite is true of lower gas prices. As a result, the composition of measures included in the intermediate Carbon Cap scenarios—40% and 60% reductions—shift as gas prices change, as shown in Figure 6-15. This shift highlights a notable and advantageous characteristic of policies focused directly on carbon regulation: the policy's technological agnosticism leads to the lowest cost combination of measures regardless of the future outcome, obviating the need to predetermine a specific technological strategy for greenhouse gas abatement.

Figure 6-15. Carbon abatement strategies under a range of gas prices



+ In the Carbon Tax scenarios, the most notable impact of the gas price sensitivities is the fact that they result in different levels of greenhouse gas emissions reduction; this is a result of the fact that a change in the gas price changes the cost-effectiveness of coal-to-gas displacement as well as the economics of investments in new renewables and energy efficiency. This sensitivity highlights an important characteristic of a tax policy that distinguishes it from one that limits the quantity of carbon emissions: a carbon tax, while providing some certainty on the cost of greenhouse gas emissions, does not provide certainty with respect to the amount of emissions reductions that will occur. Should future conditions differ from expectations, a carbon tax—however carefully designed—may not yield the anticipated level of emissions reductions.

6.5.3 IMPLICATIONS

The gas price sensitivity analysis reinforces a number of the thematic conclusions drawn from the Core Policy analysis:

+ A carbon pricing policy provides larger potential emissions reductions at considerably lower cost than increased RPS policy with less potential volatility across a wide range of natural gas prices. Across all gas price sensitivities, the RPS policy scenarios are higher cost but do not yield the emissions reductions needed to meet an 80% reduction goal.
+ The gas price sensitivity also highlights the inherent flexibility of a policy designed to achieve emissions reductions through a direct price signal on carbon. Because of the technological neutrality of carbon pricing, the optimal portfolios under a range of gas prices adjust to include different levels of coal-to-gas displacement, renewable investment, and acquisition of energy efficiency. This flexibility precludes the need for a crystal ball in effective policy design.
+ A carbon pricing policy provides a better hedge against long-term natural gas price uncertainty than increasing regional RPS goals. In a region that already relies on secondary sales of surplus power to keep rates low, an increased RPS would result in an increase in exports to external power markets and thereby increased exposure to wholesale market prices.

6.6 Low Technology Costs

6.6.1 OVERVIEW

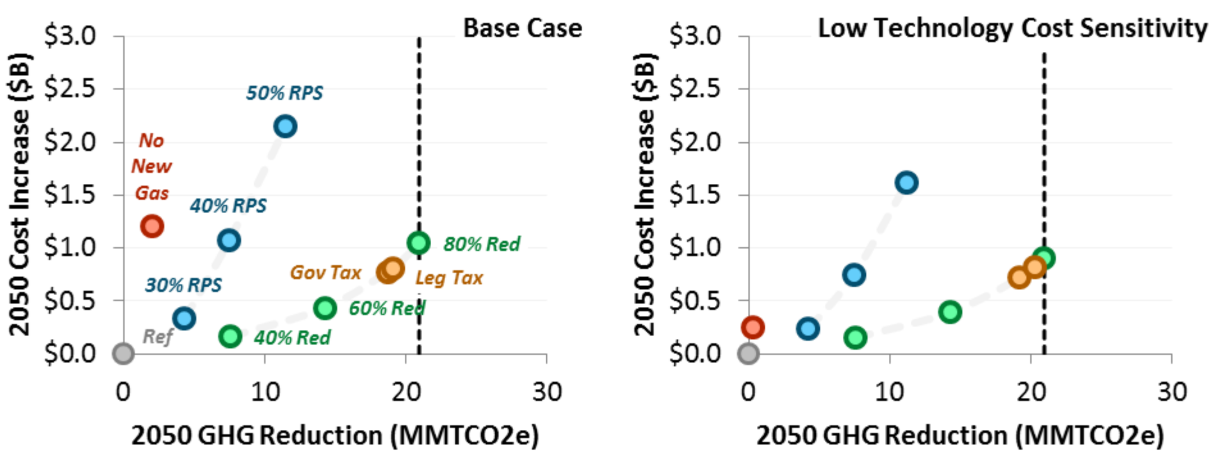
The costs of emerging technologies clean energy technologies—wind, solar, and storage—have declined as they have matured. This study assumes that cost reductions of these technologies will continue into the future; however, the magnitude of these cost reductions is inherently uncertain. This sensitivity tests the impact of a more significant cost breakthrough across multiple technologies on the Core Policy scenarios. Relative to the base case assumptions, which assume modest long-term cost reductions for these three technologies, this sensitivity assumes:

+ Long-term costs for **solar PV** and **wind** technologies are reduced by a further 20%; and
+ Long-term costs for **battery storage** technologies are reduced by a further 45%.

6.6.2 RESULTS

Figure 6-16 shows the 2050 cost and emissions impacts of each scenario under base case assumptions (left) and with low technology costs.

Figure 6-16. Impacts of Low Technology Cost sensitivity on 2050 scenario cost and emissions impacts



While the major directional relationships between the scenarios remain unchanged with low technology costs, several impacts are notable:

+ The **High RPS** scenarios exhibit the greatest sensitivity to a breakthrough in technology costs: with large incremental reductions in solar and wind costs, the cost of achieving higher regional RPS goals drops: the incremental cost of meeting a regional 50% RPS is reduced from $2.1 billion to $1.6 billion in 2050.

+ The **Carbon Cap** and **Carbon Tax** scenarios are comparably less sensitive to cost breakthroughs in renewable technology. Because these scenarios do not rely on such extensive buildouts of renewables as the High RPS scenarios, the potential cost savings is limited. Nonetheless: (1) renewable cost breakthroughs do result in some cost savings under a carbon pricing scheme, and (2) the carbon pricing scenarios still yield larger emissions reductions at considerably lower cost than the High RPS scenarios.
+ The incremental cost of the **No New Gas** scenario shrinks dramatically, as the premium associated with investments in energy storage as a substitute for new natural gas capacity is considerably lower. Nonetheless, emissions savings realized through this policy mechanism are negligible in comparison to the Reference Case.

6.6.3 IMPLICATIONS

The results of the Low Technology sensitivity reinforce several of the emerging themes from the Core Policy analysis:

+ While the High RPS policy scenarios show the greatest potential cost reduction due to technology breakthroughs, the RPS remains a comparatively ineffective policy mechanism to address greenhouse gas emissions in the Northwest. While the costs to invest in new renewable generation are reduced, there is no direct mechanism to address the continued operations of the coal fleet, the largest source of emissions reductions.
+ Much like the gas price sensitivities, this sensitivity also highlights the inherent flexibility of an approach that uses carbon pricing to achieve the least-cost combination of greenhouse gas reductions.

6.7 High California RPS Case

6.7.1 OVERVIEW

The analysis of Core Policy scenarios assumes that external jurisdictions also achieve current policy goals; in California, this requires utilities to meet a 50% RPS by 2050. However, recent activity in the California state legislature has contemplated increasing this target to a 100% RPS by 2045. Because of the significant historical role that California has played as an export market for surplus generation from the Pacific Northwest, policy changes in California have implications for utilities in the Northwest. This sensitivity investigates the implications of a decision to increase California's RPS goal to 100%. Along with the increase in the RPS target, this sensitivity also incorporates an increase in California's load forecast to reflect higher loads due to transportation and building electrification, also consistent with California's long-term greenhouse gas goals. The portfolio of resources assumed to meet California's 100% RPS goal, as well as the associated increase in load due to increased electrification, are reported in Appendix B. This sensitivity is tested against the Reference Case, the 80% Reduction case, and the 50% RPS case

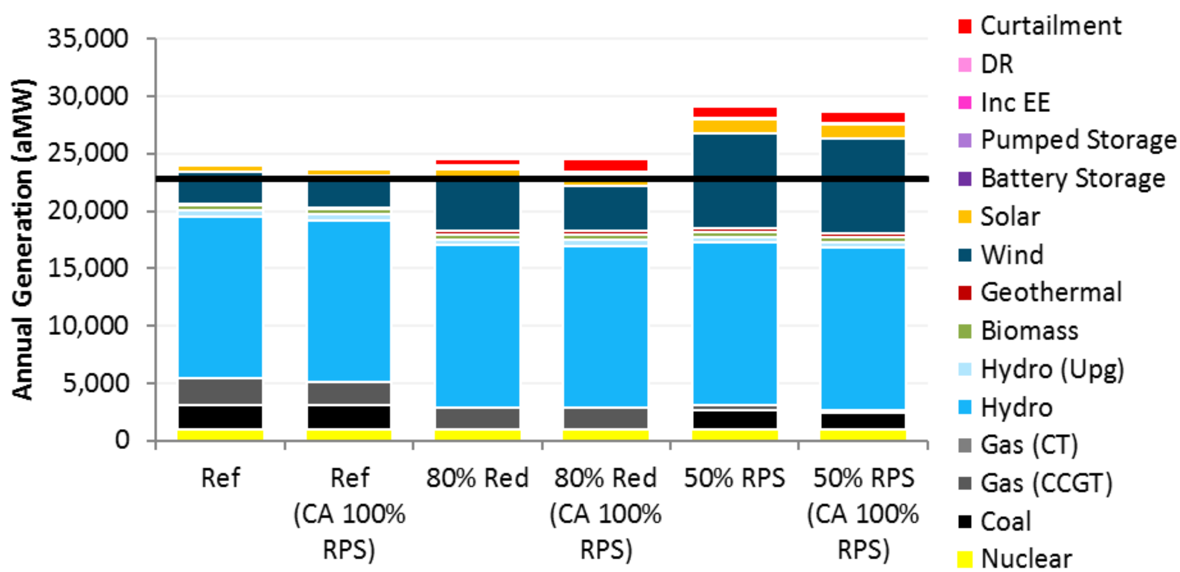
6.7.2 RESULTS

In each of the sensitivities run with California reaching a 100% RPS target by 2050, the selected resources do not vary significantly from the corresponding scenarios where California remains at 50% RPS. The impact on the generation mix in each scenario, shown in Figure 6-17, is also relatively minor. The prevailing effect, across all three scenarios, is a reduction in regional exports, as California's demand for power from the Northwest is suppressed. The corresponding impact on the Northwest portfolio varies by scenario:

+ In the **Reference Case**, the reduction in exports is due to a slight reduction in natural gas dispatch in the Northwest; the suppression of market prices in California makes it an overall less attractive market for gas resources that may have been on the margin previously.

+ in the **80% Reduction** case, the reduction exports results primarily from incremental curtailment of renewables: because, under a carbon pricing scheme, the Northwest is willing to curtail renewable generation at $0/MWh while California is willing to pay to avoid curtailment, the Northwest experiences a slight increase in renewable curtailment as California increases its policy goals.
+ in the **50% RPS** case, reduced exports result in slight decreases in coal and gas dispatch. In this scenario, the Northwest has a strong incentive to ensure that its renewable plants generate and to avoid curtailment; however, the market to sell surplus to California is unattractive because of frequent renewable curtailment. The result is that Northwest renewables increasingly displace fossil resources in the Northwest, rather than exporting to California, as the penetration of renewables in California increases.

Figure 6-17. Impact of California 100% RPS case on regional generation mix



All sensitivities in which California achieves a 100% RPS result in higher costs to the Northwest in comparison to the corresponding scenario when California remains at a 50% RPS. This effect is due two factors that reduce the potential for secondary sales revenue in the Northwest: (1) a reduction in market prices in California as 100% RPS displaces less efficient gas units and results in more frequent negative pricing, and (2) less demand for surplus power from the Northwest, as California is more frequently in surplus conditions itself. The effect of reduced secondary sales revenues is relatively uniform in its effect on both the Reference Case and the 80% Reduction case, as the two cases show relatively similar levels of net export from the Northwest—in both scenarios, costs in the Northwest increase by roughly $200 million in 2050 relative to a scenario in which California remains at its current 50% levels. However, under the scenario in which the Northwest achieves a 50% RPS and California achieves a 100% RPS, costs increase by $700 million relative to a scenario in which both entities achieve a 50% RPS. This is due to the fact that the High RPS scenarios in the Northwest rely to a much larger extent on the sale of surplus incremental renewables to offset investment costs.

Table 6-3. Cost impacts of California's increased RPS policy (100% RPS by 2050)

	CA 50% RPS ($MM/yr)	CA 100% RPS ($MM/yr)	Cost Increase ($MM/yr)
Reference Case	—	$216	+$216
80% Reduction	$1,046	$1,266	+$220
50% RPS	$2,146	$2,840	+$694

6.7.3 IMPLICATIONS

This result of the California 100% RPS sensitivity highlight the risk of making new investments with the expectation of selling additional surplus power into California markets. Wholesale market dynamics are changing rapidly as California progresses towards a 50% RPS standard by 2030, and a portfolio that meets 100% RPS in California would cause even more dramatic shifts in the economics of wholesale power transactions in the West. The 80% Reduction scenario proves to have far less downside exposure to the risk of reduced secondary revenues than a 50% RPS policy, which would result in increased reliance on secondary revenues due to the significant level of exports.

7 Conclusions and Key Findings

Recent efforts by lawmakers and state agencies in Oregon and Washington to set goals for deep, long-term reductions in greenhouse gas emissions are generating discussion on appropriate policies and technology pathways to meet these goals over time. This study seeks to contribute to this discussion, focusing on the electricity sector and its role in a deeply decarbonized energy system for the Pacific Northwest region. Because of its extensive hydropower resources and low retail rates, the Pacific Northwest faces unique questions in transitioning to an electricity sector that supports its deep decarbonization goals. This study focuses on three related questions:

+ What combination of generation resources will provide the most cost-effective sources of greenhouse gas reductions within the electric sector while meeting reliability needs?
+ What types of policies in the electric sector will enable the achievement of emissions reductions goals at least cost?
+ How will different policies impact the long-term viability of existing low-carbon resources in the Northwest, including hydro, nuclear, and energy efficiency?

Responding to these questions, this concluding section highlights and summarizes key findings from the scenario and sensitivity analysis.

The most cost-effective opportunity for reducing carbon in the Northwest is to displace existing coal generation with a combination of energy efficiency, renewables and natural gas. Currently, coal resources account for roughly 80% of the Northwest's electricity-sector greenhouse gas emissions. Although planned retirements of several regional coal plants will help reduce emissions, the remaining coal plants owned by utilities in the region will continue to produce significant greenhouse gas emissions if they continue to operate. Replacing remaining existing coal resources with a low-carbon combination of natural gas, renewable generation, and energy efficiency provides significant greenhouse gas reductions at moderate incremental cost to ratepayers: the least-cost portfolio that meets the region's 80% reduction goals eliminates coal from the portfolio at a total cost of $1 billion per year—an increase of about 6% and an average abatement cost of $50/tonne. To encourage this transition, a technology-neutral policy that focuses directly on carbon provides a consistent and universal market signal to displace coal with the least-cost mix of low- and zero-carbon resources.

Renewable generation is an important component of a low-carbon future, but using a Renewables Portfolio Standard to drive investments in renewables results in higher costs and higher carbon emissions than a policy that focuses directly on carbon. RPS policy—a mandate for renewable procurement—has been successful at driving investment in renewables in the Northwest and throughout the United States. However, it ignores the potential contributions of other greenhouse gas abatement options in the electric sector, such as energy efficiency and coal-to-gas switching. Further, at higher levels of renewable penetration, RPS policies lead to unintended consequences and introduce distortions into wholesale markets—specifically, negative market pricing during periods of renewable curtailment—creating adverse market conditions and reducing market revenues for other existing zero-carbon resources. Distortionary impact of RPS policy on wholesale prices makes the decision to reinvest and maintain these resources difficult notwithstanding their long-term value to meeting carbon goals. Ultimately, existing hydro and nuclear generators may not be able to justify continued operations if these effects become significant enough.

Meeting decarbonization goals becomes significantly more challenging and costly should existing zero-carbon resources retire. The existence of the region's zero-carbon generation fleet, comprising 31,000 MW of hydroelectric capacity and 1,200 MW of nuclear, is the foundation of the Northwest electric sector's low carbon intensity. However, these zero-carbon resources will face relicensing decisions, equipment reinvestment costs, and continued maintenance costs between now and 2050, with no guarantee that they will continue to operate. Should a portion of the existing zero-carbon fleet retire, the challenge and costs of meeting long-term decarbonization goals in the electricity sector increases significantly, as both the energy and firm capacity of these retiring resources must be replaced. In this study, replacing 3,400 MW of existing hydro or nuclear generation would require nearly 5,500 MW of new wind and solar generation as well as 2,000 MW of natural gas peaking at an annual cost of $1.6 billion by 2050. A policy that therefore encourages the retention of and reinvestment in low-cost existing zero-carbon generation resources will help contain costs of meeting carbon goals.

Prohibiting the construction of new natural gas generation results in significant additional cost to Northwest ratepayers without a significant greenhouse gas reduction benefit. This study affirms the findings of previous regional planning efforts that new investment in firm resource capacity will be needed in the region in the coming decade to ensure resource adequacy. Its results also suggest that natural gas—and specifically investment in new natural gas capacity—has an important role to play as part of a least-cost resource portfolio even under stringent greenhouse gas regulation. Future regional capacity needs can be met at relatively low cost—and with little absolute impact on greenhouse gas emissions—with new investments in low-cost gas peaking units. Because these types of units are built with the expectation of operating infrequently—generally only when needed to meet peak demands—their absolute contribution to greenhouse gas emissions is minimal. Alternatively, meeting regional resource adequacy needs exclusively with non-emitting resources will likely increase costs to ratepayers without providing a material greenhouse gas benefit. The contrast between these scenarios highlights the key finding that investments in natural gas do not inherently conflict with ambitious greenhouse gas reduction goals—in fact, investments in new natural gas generation may be pivotal to achieving emissions reductions goals reliably and at least cost.

Returning revenues raised under a carbon pricing policy to the electricity sector is crucial to mitigate higher costs to ratepayers. This study demonstrates a least-cost pathway to deep decarbonization in the electric sector in the Northwest at a moderate cost of $1 billion per year—a figure that reflects the costs of new investments and low-carbon fuel to reach this goal—and identifies carbon pricing policies as a mechanism to promote this transition efficiently. However, if a carbon pricing scheme is designed without revenue recycling to electric ratepayers, the cost of such a policy to electric ratepayers will be considerably larger, as ratepayers will bear not only the costs to invest in decarbonization but will face additional costs to purchase allowances (or pay taxes) for the remaining emissions in the electric sector. This effect could increase the cost to meet the 80% reduction goal by as much as $1 billion, doubling the costs borne by ratepayers without providing any incremental emissions reductions benefit. A carbon pricing scheme that returns a large share of the revenues raised from the electric sector back to electric ratepayers in the form of bill credits or investment credits will help contain the ratepayer impacts of meeting carbon reduction goals within the electric sector and is a common feature of carbon pricing programs adopted in other jurisdictions.

Research and development is needed for the next generation of energy efficiency measures. One of the four pillars of deep decarbonization is the need to meet ambitious conservation goals. While the region's past acquisition of conservation is a success story for mitigating load growth, the establishment of long-term carbon targets points toward the need for an evolved perspective on energy efficiency, its value, and what utilities are willing to pay to acquire it. This study demonstrates not only that measures identified by NWPCC as not cost-effective under current policy become cost-effective as a component of the least-cost greenhouse gas reduction portfolio, but that additional high-cost measures beyond today's cost-effectiveness threshold could further contribute to meeting these goals, reducing the need for new investments in renewables. Thus, while NWPCC's work to quantify the low-cost conservation potential for existing resources has laid a strong foundation for future conservation programs, research and development in the region should focus on continuing to expand the technological options available to mitigate future load growth. At the same time, promoting energy efficiency is a question for policymakers as well, as the avoided costs used to assess cost-effectiveness directly reflect state energy policies—in this respect, a carbon pricing policy lays a foundation for an energy efficiency cost-effectiveness framework that captures the inherent value of the greenhouse gas reductions that conservation provides.

Vehicle electrification is a low-cost measure for reducing carbon emissions in the transportation sector. While this study's primary focus is on how policy can most effectively facilitate carbon reductions in the electric sector, deep decarbonization literature indicates that achieving economy-wide reductions will also require the electric sector to meet new loads as transportation and buildings electrify. This study highlights vehicle electrification as one cross-sectoral opportunity to achieve economy-wide greenhouse gas reductions that not only reduces carbon but also provides net benefits to society as a whole. In this respect, transportation electrification is a least-regrets strategy for carbon abatement, but one that will require careful consideration due to impacts across multiple sectors of the economy. Additional work is needed within the region to explore how transportation electrification—and potentially electrification of other end uses—can be achieved to reduce carbon without placing undue incremental cost burdens on the electric sector as large new quantities of load materialize.

Appendix A. RESOLVE Day Sampling

A.1 Day Sampling Overview

Computation can be challenging for a model like RESOLVE that makes both investment and operational decisions across a long period of time. To alleviate this challenge, instead of simulating the system operation for an entire year, a subset of days is modeled to approximate the annual operating costs. In order to approximate the annual system operating costs while simulating only a subset of the number of days in a year, RESOLVE relies on a pre-processing sampling algorithm to select a combination of days whose characteristics are, together, representative of the conditions experienced by an electricity system over the course of multiple years. This pre-processing step relies on an extensive characterization of possible load, wind, solar, and hydro conditions, using optimization to sample a subset of conditions from the pool that, when taken in aggregate and weighted appropriately, provide a reasonable representation of the breadth of conditions observed in the historical record.

A.2 Methodology

A multi-objective optimization model is used to pick a set of days (and associated weights) to match historical conditions for key indicators while also minimizing the number of days selected. The process for selecting the set of representative days follows several steps:

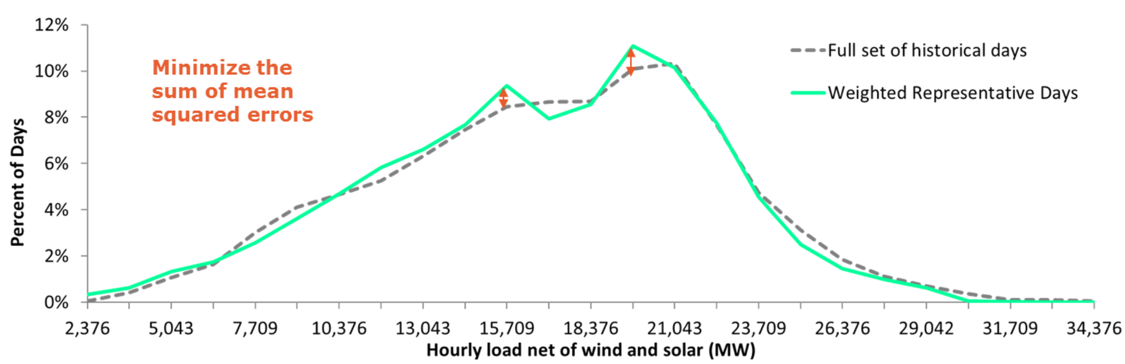
+ **The candidate pool of days is created:** Load, wind, and solar profiles are sampled from 2007 to 2009 data to represent years with different load levels, and hydro profiles are sampled from 2001, 2005, and 2011 to represent dry, average, and wet hydro years, respectively. The studies combine three load years and three hydro years to create nine synthetic years as candidate pool, by doing this, a broader range load and hydro possibilities is covered.
+ **Key variables are selected:** key variables are selected as indicators for system conditions. In this study, the variables used to characterize the representativeness of a sample include: (1)

distributions of hourly and daily load, net load, wind, and solar production; (2) distribution of hourly ramps of load net of wind and solar; (3) distributions of daily hydro generation; (4) number of days per month; and (5) site-specific annual capacity factors for wind and solar profiles. These variables can also be weighted differently, which allows the optimization model to prioritize the more important variables with higher weights when matching the distribution. This study prioritizes fit on the distributions for load, wind, and hydro conditions, as these three factors have a significant effect on the operations of the electric system.

+ **Optimization model selects an optimal set of days:** from the candidate pool of days established in the first step, the optimization selects a set of days while minimizing the mean squared errors for each of the criteria. The output from the optimization algorithm includes a set of days, as well as associated weights through which those days may be weighted to represent a historic average year.

A multi-objective optimization model is used in the day sampling process. As shown in Figure A-1 below, one component of the minimization is the alignment between historical and sampled hourly load distributions: the distribution of historical hourly net load is plotted as dotted gray line in the chart, and the model selects and weights a subset of days to match the historical distributions. The objective function is shown below:

Figure A-1. Example of net load distribution



Minimize:

$$\boldsymbol{Sum\ of\ mean\ squared\ errors - Selected\ Days\ Variable}\ \times Objective\ Adjustive\ Parameter$$

$$\boldsymbol{Sum\ of\ mean\ squared\ errors} = \sum_j (historical\ frequency_j - \ weighted\ average\ frequency_j)^2$$

$$weighted\_average\_frequency_j = \sum_d DayWeights_d \ \times day\_frequency_{d,\ j}$$

$$\boldsymbol{Selected\ days\ variable} = \textstyle\sum_d DayWeights_d{}^2$$

Days (d): the set of days in the candidate pool

Bin Frequencies(j): the set of bins in histograms of key variables

This minimization is subject to a single constraint:

$$\sum_{\boldsymbol{d}} \boldsymbol{DayWeights_d = 1}$$

Because day weights are between 0 and 1, and all of them adds up to 1, the $Selected\ days\ variable$ ranges from 0 to 1. This variable is closer to 1 when the number of days selected is less. The $Objective\ Adjustive\ Parameter$ is the tuning parameter for the relative importance between the accuracy of representing historical condition and the number of days selected. The model would prioritize selecting less days with a larger value of the parameter.

A.3 Results

The day sampling process yielded a set of 41 days that show very small deviations from the historical distributions. The details for each of these days—the calendar days used for load, wind, and solar PV; the type of hydro condition sampled; and the associated weight attributed to the day—are shown in Table A-1. Figure A-2 and Figure A-3 show the comparison of distribution between the full set of candidate days and the representative days.

Table A-1. Details for 41 days sampled for operational simulation in RESOLVE

Index	Weather Date	Hydro Condition	Day Weight	Index	Weather Date	Hydro Date	Day Weight
1	2/20/09	Normal	24.8	22	2/4/08	Wet	6.2
2	7/1/08	Normal	23.9	23	8/2/09	Normal	6.2
3	10/5/09	Normal	23.3	24	3/15/07	Dry	5.8
4	11/15/08	Wet	22.6	25	9/21/08	Wet	5.7
5	1/1/07	Normal	19.6	26	7/7/08	Normal	5.6
6	5/1/07	Dry	17.5	27	8/31/07	Wet	5.5
7	4/29/07	Normal	16.5	28	9/22/08	Dry	5.3
8	12/25/09	Normal	16.1	29	6/5/08	Normal	5.0
9	3/7/07	Normal	14.6	30	1/30/08	Dry	4.2
10	6/23/09	Normal	13.9	31	1/19/09	Wet	4.2
11	5/13/08	Normal	12.4	32	4/9/08	Dry	2.8
12	12/22/09	Normal	11.5	33	6/2/09	Dry	2.6
13	3/14/08	Normal	11.5	34	7/22/09	Wet	2.1
14	9/28/07	Normal	10.8	35	12/23/09	Normal	2.0
15	8/19/07	Dry	10.5	36	8/6/08	Dry	1.9
16	4/12/09	Wet	9.3	37	7/4/08	Wet	1.5
17	9/30/07	Normal	8.2	38	1/22/08	Dry	1.3
18	8/16/08	Normal	7.4	39	5/21/07	Normal	1.2
19	11/5/09	Normal	7.1	40	4/30/08	Dry	0.4
20	10/14/08	Dry	7.0	41	12/20/08	Dry	0.4
21	6/8/08	Wet	6.5	**Total**			**365.000**

Figure A-2. The hourly distribution of wind, solar, load, net load, and ramp rate for historical and representative days

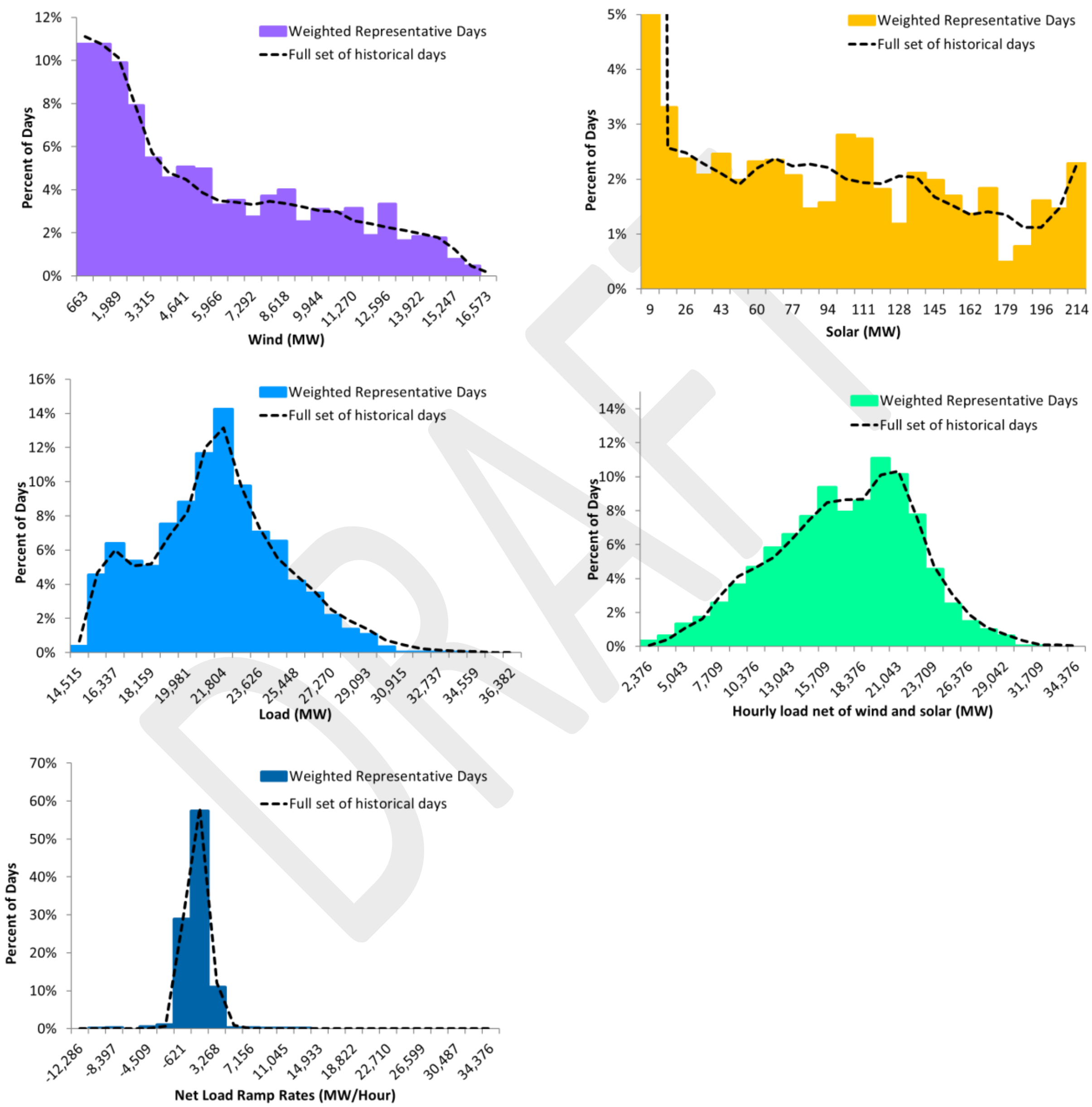
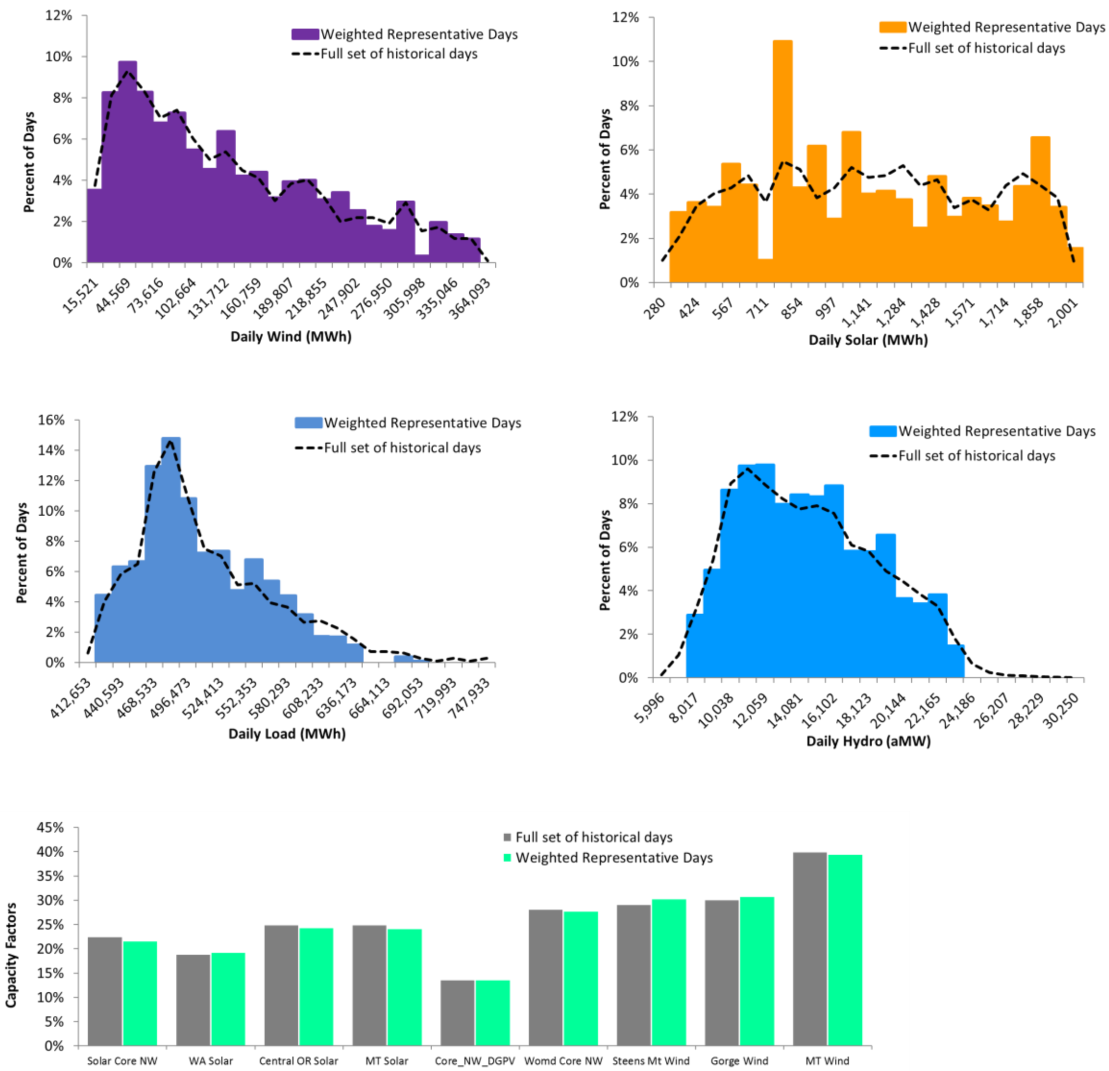


Figure A-3. Daily distributions of load, solar, wind, and hydro



Appendix B. Detailed Inputs and Assumptions

B.1 Core Northwest Load Modifiers

B.1.1 TRANSPORTATION ELECTRIFICATION

This study includes the anticipated load impact of future transportation electrification resulting from EV adoption based on the NWPCC Seventh Power Plan. Electric vehicle load forecasts are derived from the NWPCC's 'Medium' electric vehicles trajectory, and reflect a mid-range value for transportation electrification in the region. In order to develop a forecast for electric vehicle loads using NWPCC data, the market share of electric vehicles for Washington and Oregon was used and multiplied by the total expected EV loads in the region to determine the impact of total electric vehicle loads on the Core Northwest region. The market share for Washington and Oregon is 80%, hence adoption of electric vehicles is concentrated in the Core Northwest region.

B.1.2 ENERGY EFFICIENCY

This study relies on the characterization of cost-effective energy efficiency developed in the Seventh Power Plan, which identifies 3,770 aMW of cost-effective potential within the Pacific Northwest by 2035. In order to account for differences in geographic scope and analysis horizon between these studies, several adjustments are applied to this potential:

+ **Difference in geographic scope (-12%):** Because this study focuses on a narrower geographic scope than the Seventh Power Plan, the efficiency potential is derated according to the load-ratio share of the NWPCC's planning footprint that is captured within this study.
+ **Difference in assumed load growth (+31%):** this study assumes a different growth rate than the Seventh Power Plan, and also focuses on the state of the system fifteen years after the conclusion

of the Seventh Power Plan's analysis horizon. Opportunities for energy efficiency are assumed to scale linearly with load growth, such that the larger increase in load in this study reflects a larger potential market for cost-effective efficiency. This adjustment captures the difference between the Seventh Power Plan's lower load growth rate over twenty years and this study's higher load growth rate over 35 years.

+ **Difference in achievability (+17%):** in the Seventh Power Plan, NWPCC assumes that 85% of cost-effective potential is achievable within a twenty-year planning horizon. Because of the longer planning horizon considered in this study, this constraint is relaxed to assume 100% of cost-effective potential is achievable by 2050. This adjustment is thus calculated as the reciprocal of NWPCC's 85% derate.

In total, these multiplicative adjustments translate to an assumed cost-effective efficiency potential of 5,100 aMW by 2050 within the Core Northwest assumed in this study.

B.1.3 BEHIND-THE-METER PV

The assumptions for BTM PV adoption are based on the values published by the NWPCC for the entire NW region through 2035. NWPCC provides expected energy production of behind-the-meter solar PV installations annually through 2035; this forecast is directly used in this study. Beyond 2035, a 5-year linear growth is applied to the forecasts. It is assumed that the BTM PV penetration is concentrated in Washington and Oregon.

Table B-1. Regional behind-the-meter solar PV adoption forecast

Category	2015	2020	2030	2040	2050
Installed Capacity (MW)	115	200	362	*532*	*700*
Load Impact (aMW)	22	38	69	*101*	*133*

B.2 Core Northwest Baseline Resources

B.2.1 EXISTING COAL PLANTS

Table B-2 lists the coal plants included in the Core Northwest generation portfolio along with key characteristics: total plant size, share allocated to the Core Northwest, and assumed retirement date, if applicable.

Table B-2. Coal plants included in the Core Northwest portfolio

Plant	Location	Core NW Share	Total Capacity (MW)	Core NW Capacity (MW)	Retirement Date
Boardman	OR	90%	585	527	12/31/2020
Centralia 1	WA	100%	670	670	12/31/2020
Centralia 2	WA	100%	670	670	12/31/2024
Cholla 4	AZ	32%	380	123	12/31/2024
Colstrip 1-2	MT	50%	614	307	7/31/2022
Colstrip 3-4	MT	63%	1480	936	
Craig 1-2	CO	6%	856	53	
Dave Johnston 1-4	WY	32%	762	247	
Hayden 1	CO	8%	190	15	12/31/2030
Hayden 2	CO	4%	275	12	12/31/2036
Hunter 1	UT	30%	471	143	
Hunter 2	UT	20%	430	84	
Hunter 3	UT	32%	460	149	
Huntington 1-2	UT	32%	909	295	
Jim Bridger 1-4	WY	22%	2,111	458	
Naughton 1-2	WY	32%	357	116	
Naughton 3	WY	32%	330	107	1/1/2018
Wyodak	WY	26%	340	88	
Total			**11,997**	**5,000**	

B.2.2 EXISTING NATURAL GAS PLANTS

Table B-3 lists the gas plants in the Core Northwest generation portfolio along with key characteristics: plant size, type, and assumed retirement date, if applicable.

Table B-3. Gas units in the Core NW and assumed retirement dates

Generator Name	Technology	Location	Capacity (MW)	Retirement Date
Alden Bailey	Gas (CT)	OR	11	
Bangor Submarine Base 2	Gas (CT)	WA	10	4/15/2030
Beaver 8	Gas (CT)	OR	25	
Beaver CC	Gas (CCGT)	OR	586	
Boulder Park 1-6	Gas (CT)	WA	25	
Carty Gen Sta CC	Gas (CCGT)	OR	440	
Centralia CC	Gas (CCGT)	WA	268	
Chehalis CC	Gas (CCGT)	WA	507	
Coyote Sprg CC – 1	Gas (CCGT)	OR	235	12/31/2040
Coyote Sprg CC – 2	Gas (CCGT)	OR	287	
Encogen CC	Gas (CCGT)	WA	176	
Ferndale CC	Gas (CCGT)	WA	253	12/31/2034
Franklin Grays 1-4	Gas (CT)	WA	46	
Frederickson 1-2	Gas (CT)	WA	178	12/31/2035
Frederickson CC	Gas (CCGT)	WA	260	
Fredonia 1-4	Gas (CT)	WA	376	
Fort James Cogen	Gas (CT)	WA	53	
Goldendale CC	Gas (CCGT)	WA	257	
Grays Harbor CC	Gas (CCGT)	WA	637	12/31/2040
Hermiston CC	Gas (CCGT)	OR	648	12/31/2044
Hermiston CC 1-2	Gas (CCGT)	OR	486	12/31/2035
Kettle Falls 2	Gas (CT)	WA	7	
Klamath Cogen CC	Gas (CCGT)	OR	490	
Klamath Exp GT 1-4	Gas (CT)	OR	118	
March Point CC	Gas (CCGT)	WA	167	
Mint Farm CC	Gas (CCGT)	WA	276	

Generator Name	Technology	Location	Capacity (MW)	Retirement Date
Morrow Pwr GT	Gas (CT)	OR	31	
Northeast 1-2	Gas (CT)	WA	62	
Port Westwrd 1 CC	Gas (CCGT)	OR	430	
Port Westwrd 2, 1 – 12	Gas (ICE)	OR	220	
Puget_Sound	Gas (CT)	WA	12	4/15/2030
Rathdrum 1-2	Gas (CT)	ID	166	
Rathdrum CC	Gas (CCGT)	ID	248	
River Road CC	Gas (CCGT)	WA	220	12/31/2040
Standby Aggregate	Gas (CT)	OR	62	4/15/2030
Sumas Power CC	Gas (CCGT)	WA	139	
Tesoro ICs	Gas (CT)	WA	18	
Univ of OR CC	Gas (CCGT)	OR	11	
Whitehorn 2-3	Gas (CT)	WA	169	
Total			**8,609**	

B.3 External Loads and Resources

B.3.1 CALIFORNIA

This study generally relies on a characterization of loads and resources in California that assumes California achieves its current energy policy goals, including aggressive achievement of energy efficiency and a 50% RPS goal by 2030 (held constant thereafter). The portfolio of resources assumed to satisfy these policy goals in California is developed by E3 using an internal California version of the RESOLVE model.

Table B-4. Demand forecast for California loads

	2020	2030	2040	2050
Annual Energy (aMW)	36,224	36,433	37,739	40,417
Annual Peak (MW)	63,691	64,059	66,355	71,065

Table B-5. Assumed installed capacity of California resources

	Installed Capacity (MW)			
Generation Type	2020	2030	2040	2050
Nuclear	3,379	1,079	1,079	—
Coal	1,800	—	—	—
Gas (CHP)	1,684	1,684	—	—
Gas (CCGT)	20,742	22,542	22,542	22,542
Gas (CT)	19,415	13,044	13,044	17,324
Hydro	13,204	13,204	13,204	13,204
Biomass	842	842	842	842
Geothermal	1,622	1,932	2,309	3,151
Solar	19,043	41,224	46,361	51,878
Wind	9,907	11,390	11,390	11,390
Pumped Storage	1,832	1,832	1,832	1,832
Battery Storage	902	1,325	1,325	1,325
Demand Response	2,268	2,268	2,268	2,268

In addition to modeling how the California fleet would evolve under current policy (50% RPS), this study also includes a sensitivity in which California reaches a 100% RPS goal by 2050, reflecting recent discussions in the state legislature. This assumption is paired with an assumed increase in electrification of buildings and transportation to create a scenario consistent with California's long-term reductions goals. The assumed load and the portfolio of resources available to meet it is based on internal analysis using PATHWAYS to characterize the electrification loads and RESOLVE to optimize California's generation mix to serve that load. The assumptions for this sensitivity are shown in Table B-6 and Table B-7.

Table B-6. Demand forecast for California loads, CA 100% RPS sensitivity

	2020	2030	2040	2050
Annual Energy (aMW)	36,089	36,963	46,733	54,056
Annual Peak (MW)	63,455	64,991	82,170	95,046

Table B-7. Assumed installed capacity of California resources, CA 100% RPS sensitivity

	Installed Capacity (MW)			
Generation Type	**2020**	**2030**	**2040**	**2050**
Nuclear	3,379	1,079	1,079	—
Coal	1,800	—	—	—
Gas (CHP)	1,684	1,684	—	—
Gas (CCGT)	20,742	22,542	22,542	22,542
Gas (CT)	19,415	13,044	13,044	12,898
Hydro	13,204	13,204	13,204	13,204
Biomass	842	842	842	842
Geothermal	1,622	1,592	3,151	3,151
Solar	17,661	38,960	94,340	145,696
Wind	9,907	11,336	12,524	12,524
Pumped Storage	1,832	1,832	1,832	1,832
Battery Storage	902	1,429	24,873	59,573
Demand Response	2,268	2,268	2,268	2,268

B.3.2 OTHER NORTHWEST

Assumptions for loads and resources in the Other Northwest zone are developed using similar data sets and guiding principles to those used in the Core Northwest region. The demand forecast reflects a share of the regional energy efficiency identified by the NWPCC. The portfolio of generation resources is based on TEPPC's 2026 Common Case; additional capacity resources are added through 2050 to meet resource adequacy needs.

Table B-8. Demand forecast for Other Northwest loads

	2020	2030	2040	2050
Annual Energy (aMW)	9,381	10,470	11,739	13,214
Annual Peak (MW)	14,753	16,465	18,461	20,780

Table B-9. Assumed installed capacity of Other Northwest resources

	Installed Capacity (MW)			
Generation Type	2020	2030	2040	2050
Nuclear	3,379	1,079	1,079	—
Coal	6,497	5,875	5,820	5,820
Gas (CHP)	—	—	—	—
Gas (CCGT)	2,938	5,485	7,370	8,626
Gas (CT)	2,070	2,218	2,654	4,000
Hydro	3,253	3,253	3,253	3,253
Biomass	24	24	24	24
Geothermal	140	140	140	140
Solar	362	362	362	362
Wind	2,061	2,194	2,564	2,994
Pumped Storage	—	—	—	—
Battery Storage	—	—	—	—
Demand Response	1,003	1,003	1,003	1,003

B.3.3 SOUTHWEST

Loads and resources in the Southwest region are based on the TEPPC 2026 Common Case. Load growth is extrapolated through 2050; additional renewable resources are added to maintain compliance with increasing RPS goals; and new capacity resources are added to meet growing peak demand.

Table B-10. Demand forecast for Southwest loads

	2020	2030	2040	2050
Annual Energy (aMW)	13,476	15,646	18,165	21,090
Annual Peak (MW)	25,478	29,580	34,343	39,874

Table B-11. Assumed installed capacity of Southwest resources

	Installed Capacity (MW)			
Generation Type	**2020**	**2030**	**2040**	**2050**
Nuclear	2,858	2,858	2,858	—
Coal	7,344	7,344	7,207	7,207
Gas (CHP)	—	—	—	—
Gas (CCGT)	14,440	14,507	14,507	18,708
Gas (CT)	7,476	8,499	11,895	16,530
Hydro	1,838	1,838	1,838	1,838
Biomass	35	35	35	35
Geothermal	—	—	—	—
Solar	1,545	1,840	2,661	3,614
Wind	3,165	3,165	3,165	3,165
Pumped Storage	—	—	—	—
Battery Storage	—	—	—	—
Demand Response	516	516	516	516

B.3.4 NEVADA

Loads and resources in the Nevada region are based on the TEPPC 2026 Common Case. Load growth is extrapolated through 2050; additional renewable resources are added to maintain compliance with increasing RPS goals; and new capacity resources are added to meet growing peak demand.

Table B-12. Demand forecast for Nevada loads

	2020	2030	2040	2050
Annual Energy (aMW)	4,485	5,172	5,964	6,878
Annual Peak (MW)	7,778	8,969	10,343	11,928

Table B-13. Assumed installed capacity of Nevada resources

	Installed Capacity (MW)			
Generation Type	2020	2030	2040	2050
Nuclear	—	—	—	—
Coal	764	242	242	—
Gas (CHP)	—	—	—	—
Gas (CCGT)	5,328	5,399	6,763	8,461
Gas (CT)	1,856	2,261	2,261	2,379
Hydro	2,092	2,092	2,092	2,092
Biomass	3	3	3	3
Geothermal	451	451	451	451
Solar	610	805	1,345	1,967
Wind	704	704	704	704
Pumped Storage	—	—	—	—
Battery Storage	—	—	—	—
Demand Response	275	275	275	275

B.3.5 ROCKY MOUNTAINS

Loads and resources in the Rocky Mountain region are based on the TEPPC 2026 Common Case. Load growth is extrapolated through 2050; additional renewable resources are added to maintain compliance with increasing RPS goals; and new capacity resources are added to meet growing peak demand.

Table B-14. Demand forecast for Rocky Mountain loads

	2020	2030	2040	2050
Annual Energy (aMW)	8,249	9,488	10,914	12,554
Annual Peak (MW)	12,764	14,682	16,889	19,427

Table B-15. Assumed installed capacity of Rocky Mountain resources

	Installed Capacity (MW)			
Generation Type	2020	2030	2040	2050
Nuclear	—	—	—	—
Coal	7,000	7,000	5,875	5,264
Gas (CHP)	—	—	—	—
Gas (CCGT)	3,653	4,134	7,701	9,710
Gas (CT)	3,663	3,734	3,734	5,145
Hydro	1,357	1,357	1,357	1,357
Biomass	3	3	3	3
Geothermal	—	—	—	—
Solar	116	116	116	116
Wind	2,748	2,921	3,401	3,952
Pumped Storage	—	—	—	—
Battery Storage	—	—	—	—
Demand Response	525	525	525	525

B.4 Renewable Supply Curve

The supply curve of potential renewable resource options consists of a number of different technologies, including wind, solar PV, geothermal, and upgrades to existing hydro facilities.[37] This section describes the sources and key assumptions for each of the renewable resources included.

B.4.1 GEOTHERMAL

Potential for new geothermal within the Core Northwest is relatively limited. This study's assumptions are based on the NWPCC Seventh Power Plan, which identifies 450 MW of geothermal resources throughout the state of Oregon.

B.4.2 HYDRO

In 2014, the Council commissioned a study by the Northwest Hydropower Association to identify the potential for new hydroelectric generation within the region.[38] The study identified a total of 600 MW of incremental hydroelectric potential within the region through four types of projects: upgrades to existing facilities (388 MW), general assessments (90 MW), conduit exemptions and hydrokinetic projects (64 MW), and retrofits of existing non-powered dams (57 MW). Thecapital cost for new hydro projects is based on the US Department of Energy's *Hydropower Vision* study.[39]

B.4.3 SOLAR PV

In the past several years, reductions in solar PV cost has made development increasingly competitive, even in areas like the Pacific Northwest where the relative capacity factor is reduced. To capture the most recent

[37] Biomass was not considered in the supply curve for new renewable resources because of a lack of data indicating significant available potential. This assumption is not meant to suggest that developable biomass resources could not contribute to a least-cost greenhouse gas reduction strategy; the types of technology-agnostic policies that this study's results support would allow new biomass resources to compete on a level playing field with other zero-carbon generation technologies.
[38] Available at: **https://www.nwcouncil.org/media/7148577/1.pdf**
[39] Available at: **https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-Chapter-3-10212016.pdf**

industry trends, this study draws upon several sources to characterize the solar PV resource options in the Pacific Northwest, including the Seventh Power Plan, E3's WECC Cost & Performance Assessment, and the California Public Utilities Commission's recently published Proposed Reference System Plan.

Four options for new solar PV resources are considered within RESOLVE:[40]

+ **Eastern Washington & Oregon** solar PV resources offer perhaps the highest quality solar resources within the region. While not considered explicitly in the Seventh Power Plan, recent cost reductions have made such projects increasingly cost competitive and potentially commercially viable. Based on the significant potential to interconnect new renewables to the existing transmission system in the Columbia River Basin identified in the Seventh Power Plan, this study assumes that up to 4,000 MW of new solar PV resources could be interconnected to the BPA system east of the Cascades without requiring major network upgrades.[41] Once this limit is reached, additional solar PV resources can be developed with an assumed transmission upgrade cost equal to 1.5 times the embedded cost of BPA's transmission network service rate.
+ **Western Washington & Oregon** solar PV resources have considerably worse performance. Nonetheless, their proximity to major load centers means that significant quantities may be interconnected without requiring transmission upgrades. The Seventh Power Plan assumes that up to 7,600 MW of west-side solar resources could be developed without triggering network upgrades on the BPA system.
+ **Southern Oregon** (or Northern California) solar PV resources offer an alternative option for new renewable development in the Northwest, potentially allowing utilities to develop higher quality resources at lower latitudes that will counterflow against prevailing power flows between California and the Northwest. To explore this potential option, this study includes 1,000 MW of

[40] The resources discussed here reflect the options for new utility-scale solar PV. Customer solar PV is not treated as a resource option in RESOLVE, but is instead assumed to follow a trajectory of adoption meant to reflect expected customer behavior based on customer decisions to invest in solar PV under existing net metering tariffs.

[41] In total, this study assumes that a total of 8,000 MW of new wind and solar (4,000 MW of each) can be developed in the Columbia River Basin east of the Cascades. This exceeds the Seventh Power Plan's estimate of the potential for new wind resources alone to interconnect without major upgrades; this study assumes that the diversity between wind and solar resources would allow a slight increase in the amount of new renewable development that could occur on the existing system.

potential southern Oregon resources—in reality, the potential for this type of development is significantly larger.

+ **Southern Idaho** solar PV resources are characterized based on the Seventh Power Plan, which considers up to 1,284 MW of new solar PV resources along with transmission upgrades.

B.4.4 WIND

Wind generation has become the predominant technology pathway for utilities in the Northwest to reach the RPS policy goals set by state legislatures. Most of this development has historically occurred within the Columbia River Basin; this study considers a broader set of options, including new wind resources located outside the region that would be delivered to customers in the region via new transmission investments. Four wind resources are included in this study:

+ Wind resources in the **Columbia River Basin** are considered in two tranches: (1) those that can be interconnected to the existing system, and (2) those that will require network upgrades:
  - Existing transmission: this study assumes that 4,000 MW of new wind can be developed without significant transmission upgrades on the BPA network. The amount assumed in this study has been reduced from the amount identified in the Seventh Power Plan (6,500 MW) since this study also assumes that a significant quantity of new eastern Oregon/Washington solar PV (4,000 MW) can also be interconnected to the existing transmission system without major upgrades.
  - Network upgrades: beyond the 4,000 MW threshold that is assumed to interconnect to the existing system, this study assumes that network upgrades will be required for the next tranche of wind in the gorge. In the absence of studies to evaluate the specific transmission needs at penetrations this large, this study assumes that the incremental cost of transmission upgrades will be 50% above the embedded cost of BPA network service. In addition, the quality of available wind potential is assumed to degrade at this level of penetration; the capacity factor for this tranche is reduced from 32% to 28%.

- Wind resources in Montana are characterized based on the potential identified in the NWPCC Seventh Power Plan. The Seventh Plan identifies four options for delivery of Montana wind resources to the Northwest with varying costs: (1) Colstrip transmission system (2,000 MW); (2) existing transmission (100 MW); (3) new transmission (200 MW); and (4) transmission upgrades (900 MW). For the purposes of this study, the potential in this final fourth tier was increased to 3,000 MW to ensure sufficient potential was available in the higher penetration renewable scenarios. The costs of transmission under each option was derived from costs published in the Seventh Power Plan.
- **Steens Mountain** wind resources in southern Oregon are quantified based on viable sites identified in NREL's WIND Toolkit. In total, 977 MW of new potential is identified in this data set; this is assumed to be available on BPA's existing network.
- **Wyoming** is a potential source of new high-quality resources but would likely require substantial new transmission to deliver to loads in Washington and Oregon. Since Wyoming wind resources are not considered in the Seventh Power Plan, this study relies on a combination of data sources to characterize the options for wind from Wyoming. Many studies have indicated that the potential for Wyoming wind development is not practically constrained; this study assumes two bundles of 3,000 MW are available to ratepayers in the Northwest. These bundles are available at increasing transmission costs—the transmission cost for the first bundle is based on estimates of cost for Pacificorp's Gateway transmission project; the cost of the second bundle is assumed to be 50% higher than the first.

B.5 Energy Storage Cost Projections

Cost projections for energy storage across the analysis are shown in Table B-16. The cost conventions used for energy storage reflect the unique nature of the resource and are broken into components related to the capacity of the system ($/kW) as well as the size of the storage reservoir ($/kWh). The all-in cost for new energy storage is the sum of the capacity component and the energy component multiplied by the duration of the storage resource; for example, the all-in cost for a new pumped storage development with twelve hours of capacity is $2,875/kW ($1,307/kW + 12 hrs * $131/kWh).

Table B-16. Energy storage cost assumptions

Resource	Cost Component	2020	2030	2040	2050
Pumped Storage	Capital Cost - Power ($/kW)	$1,307	$1,307	$1,307	$1,307
	Capital Cost - Energy ($/kWh)	$131	$131	$131	$131
	Levelized Power Cost ($/kW-yr)	**$146**	**$146**	**$146**	**$146**
	Levelized Energy Cost ($/kWh-yr)	**$12**	**$12**	**$12**	**$12**
Li-Ion Battery	Capital Cost - Power ($/kW)	$485	$265	$265	$265
	Capital Cost - Energy ($/kWh)	$523	$286	$286	$286
	Levelized Power Cost ($/kW-yr)	**$50**	**$28**	**$28**	**$28**
	Levelized Energy Cost ($/kWh-yr)	**$69**	**$38**	**$38**	**$38**
Flow Battery	Capital Cost - Power ($/kW)	$2,300	$1,596	$1,596	$1,596
	Capital Cost - Energy ($/kWh)	$259	$180	$180	$180
	Levelized Power Cost ($/kW-yr)	**$274**	**$190**	**$190**	**$190**
	Levelized Energy Cost ($/kWh-yr)	**$31**	**$21**	**$21**	**$21**

Table B-17. Energy storage cost assumptions in Low Technology Cost sensitivity

Resource	Cost Component	2020	2030	2040	2050
Li-Ion Battery	Capital Cost - Power ($/kW)	$345	$164	$164	$164
	Capital Cost - Energy ($/kWh)	$290	$137	$137	$137
	Levelized Power Cost ($/kW-yr)	**$36**	**$17**	**$17**	**$17**
	Levelized Energy Cost ($/kWh-yr)	**$34**	**$16**	**$16**	**$16**
Flow Battery	Capital Cost - Power ($/kW)	$1,737	$1,088	$1,088	$1,088
	Capital Cost - Energy ($/kWh)	$190	$119	$119	$119
	Levelized Power Cost ($/kW-yr)	**$207**	**$130**	**$130**	**$130**
	Levelized Energy Cost ($/kWh-yr)	**$23**	**$14**	**$14**	**$14**

B.6 Fuel Price Forecasts

Table B-18 and Table B-19 show the annual commodity fuel price forecasts for coal and gas, respectively, as well as the delivered burnertip price forecasts for each region in the Western Interconnection.

Table B-18. Annual average gas price forecasts, Henry Hub and regional burnertip prices

	Annual Average Price (2016 $/MMBtu)				
Location	**2020**	**2030**	**2040**	**2050**	CAGR (2020-'50)
Henry Hub	$2.63	$3.55	$5.07	$5.83	3%
California	$3.47	$4.37	$5.89	$6.65	2%
Core Northwest	$2.93	$3.83	$5.35	$6.11	2%
Nevada	$3.19	$4.09	$5.61	$6.38	2%
Other Northwest	$2.55	$3.45	$4.97	$5.73	3%
Rockies	$2.53	$3.43	$4.95	$5.71	3%
Southwest	$3.00	$3.89	$5.41	$6.17	2%

Table B-19. Annual average coal price forecasts, Powder River Basin and regional burnertip prices

	Annual Average Price (2016 $/MMBtu)				
Location	**2020**	**2030**	**2040**	**2050**	**CAGR (2020-'50)**
Powder River Basin	$0.74	$1.01	$1.11	$1.15	1.5%
California	$2.00	$2.26	$2.36	$2.40	0.6%
Core Northwest	$1.79	$2.06	$2.16	$2.20	0.7%
Nevada	$2.00	$2.26	$2.36	$2.40	0.6%
Other Northwest	$1.47	$1.74	$1.84	$1.87	0.8%
Rockies	$1.66	$1.93	$2.03	$2.07	0.7%
Southwest	$2.00	$2.26	$2.36	$2.40	0.6%

Appendix C. Detailed Scenario Results

C.1 Reference Case

Table C-1. Cumulative new generation capacity & annual generation mix, Reference Case

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,127	2,045	2,072	2,124
Gas (CCGT)	-	-	501	1,842	238	1,738	1,836	2,270
Gas (CT)	-	1,023	3,505	7,153	-	-	-	14
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,140	14,140
Hydro (Upg)	349	349	413	539	349	349	413	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	193	-	-	-	193
Wind	-	-	2,126	2,126	1,803	1,843	2,686	2,721
Solar	1,026	2,007	2,036	2,036	250	512	520	534
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					6	280	293	385
Exports					(3,349)	(3,096)	(2,637)	(1,681)

C.2 Carbon Cap Cases

C.2.1 40% REDUCTION

Table C-2. Cumulative new generation capacity & annual generation mix, 40% Reduction scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,127	2,045	2,064	1,328
Gas (CCGT)	-	-	191	1,842	238	1,738	1,771	2,307
Gas (CT)	-	1,023	3,815	6,814	-	-	-	1
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,140	14,140
Hydro (Upg)	349	349	413	539	349	349	413	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	405	-	-	-	405
Wind	-	-	2,126	2,126	1,804	1,836	2,675	2,660
Solar	1,026	2,007	2,036	2,220	248	519	531	555
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	30	-	-	-	30
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					5	278	284	220
Exports					(3,348)	(3,095)	(2,555)	(945)

C.2.2 60% REDUCTION

Table C-3. Cumulative new generation capacity & annual generation mix, 60% Reduction scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,127	2,045	1,761	503
Gas (CCGT)	-	-	-	1,842	238	1,738	1,259	2,362
Gas (CT)	-	1,023	3,904	6,258	-	-	-	0
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,140	14,140
Hydro (Upg)	349	349	418	539	349	349	418	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	405	-	-	-	405
Wind	-	-	2,126	3,427	1,806	1,844	2,680	3,240
Solar	1,026	2,007	2,036	3,010	246	511	522	723
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	30	60	-	-	30	60
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					4	276	195	300
Exports					(3,347)	(3,092)	(1,681)	(1,032)

C.2.3 80% REDUCTION

Table C-4. Cumulative new generation capacity & annual generation mix, 80% Reduction scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,127	2,016	1,184	-
Gas (CCGT)	-	-	-	1,842	238	1,553	1,352	1,849
Gas (CT)	-	1,022	3,758	5,147	-	-	-	-
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,139	14,139
Hydro (Upg)	349	349	455	539	349	349	455	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	405	-	-	-	405
Wind	-	-	2,126	6,277	1,806	1,836	2,644	4,372
Solar	1,026	2,011	2,036	4,098	247	519	521	949
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	67	231	-	-	67	231
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					6	267	210	149
Exports					(3,349)	(2,869)	(1,249)	(1,393)

C.3 Carbon Tax Cases

C.3.1 LEG TAX PROPOSAL

Table C-5. Cumulative new generation capacity & annual generation mix, Leg Tax scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	162	9	23	27
Gas (CCGT)	-	-	739	1,842	1,385	2,007	2,445	2,179
Gas (CT)	-	1,009	3,076	5,814	-	-	-	0
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,140	14,140
Hydro (Upg)	349	349	349	539	349	349	349	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	405	-	-	-	405
Wind	-	-	1,949	5,136	1,801	1,833	2,563	3,978
Solar	1,808	2,178	2,819	3,142	431	522	708	754
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	30	97	-	-	30	97
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					16	261	256	277
Exports					(1,720)	(1,311)	(1,190)	(1,156)

C.3.2 GOV TAX PROPOSAL

Table C-6. Cumulative new generation capacity & annual generation mix, Gov Tax scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	4	5	16	35
Gas (CCGT)	-	-	739	1,842	1,514	2,000	2,418	2,252
Gas (CT)	-	994	3,043	5,861	-	-	-	0
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,140	14,140	14,140	14,140
Hydro (Upg)	349	349	349	539	349	349	349	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	-	405	-	-	-	405
Wind	-	-	2,126	4,845	1,791	1,809	2,626	3,846
Solar	1,808	2,239	2,819	3,106	440	547	709	759
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	30	97	-	-	30	97
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					21	245	241	301
Exports					(1,696)	(1,285)	(1,205)	(1,135)

C.4 High RPS Cases

C.4.1 30% RPS

Table C-7. Cumulative new generation capacity & annual generation mix, 30% RPS scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,099	2,035	2,031	2,055
Gas (CCGT)	-	-	-	1,842	196	1,631	1,478	1,382
Gas (CT)	-	806	3,330	6,040	-	-	-	2
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,141	14,140	14,140	14,140
Hydro (Upg)	349	349	539	539	349	349	539	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	405	405	-	-	405	405
Wind	-	362	2,316	5,804	1,803	1,982	2,751	4,321
Solar	1,769	2,707	2,819	3,213	419	671	700	802
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					5	243	232	196
Exports					(3,448)	(3,242)	(2,953)	(2,602)

C.4.2 40% RPS

Table C-8. Cumulative new generation capacity & annual generation mix, 40% RPS scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,099	2,001	2,009	1,963
Gas (CCGT)	-	-	-	1,842	196	1,365	979	772
Gas (CT)	-	806	3,330	6,040	-	-	0	3
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,141	14,140	14,139	14,139
Hydro (Upg)	349	349	539	539	349	349	539	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	405	405	-	-	405	405
Wind	-	362	2,316	5,804	1,801	2,586	4,020	6,036
Solar	1,769	2,707	2,819	3,213	422	674	740	1,234
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					5	205	165	102
Exports					(3,448)	(3,510)	(3,674)	(3,951)

C.4.3 50% RPS

Table C-9. Cumulative new generation capacity & annual generation mix, 50% RPS scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,103	1,960	1,947	1,654
Gas (CCGT)	-	-	-	597	200	1,094	580	428
Gas (CT)	-	-	2,326	5,899	-	-	1	1
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,141	14,139	14,139	14,137
Hydro (Upg)	349	539	539	539	349	539	539	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	301	405	405	-	301	405	405
Wind	-	2,404	8,491	16,681	1,797	2,700	5,160	8,245
Solar	1,684	2,694	3,860	5,104	406	676	910	1,171
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	-	-	-	-	-
Pumped Storage	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-
DR	-	1,271	1,414	1,559	-	-	-	-
Imports					6	169	112	53
Exports					(3,438)	(3,769)	(4,469)	(5,393)

C.5 'No New Gas' Case

Table C-10. Cumulative new generation capacity & annual generation mix, Gov Tax scenario

	Cumulative New Installed Capacity (MW)				Annual Generation (aMW)			
	2020	2030	2040	2050	2020	2030	2040	2050
Nuclear	-	-	-	-	1,004	1,004	1,004	1,004
Coal	-	-	-	-	3,098	2,045	2,049	2,105
Gas (CCGT)	-	-	-	-	195	1,656	1,663	1,551
Gas (CT)	-	-	-	-	-	-	-	3
Gas (ICE)	-	-	-	-	-	-	-	-
Hydro	-	-	-	-	14,141	14,140	14,144	14,143
Hydro (Upg)	349	349	539	539	349	349	539	539
Biomass	-	-	-	-	371	371	371	371
Geothermal	-	-	405	405	-	-	405	405
Wind	-	-	389	2,126	1,800	1,823	1,994	2,675
Solar	1,768	2,245	2,819	3,010	422	538	703	742
Customer Solar	-	-	-	-	38	69	101	133
Battery Storage	-	-	-	1,832	-	-	-	(31)
Pumped Storage	-	444	2,545	5,000	-	(5)	(25)	(19)
Energy Efficiency	3	137	312	486	3	137	312	486
DR	-	1,271	1,414	1,559	1,004	1,004	1,004	1,004
Imports					5	285	289	549
Exports					(3,450)	(3,157)	(2,749)	(1,908)