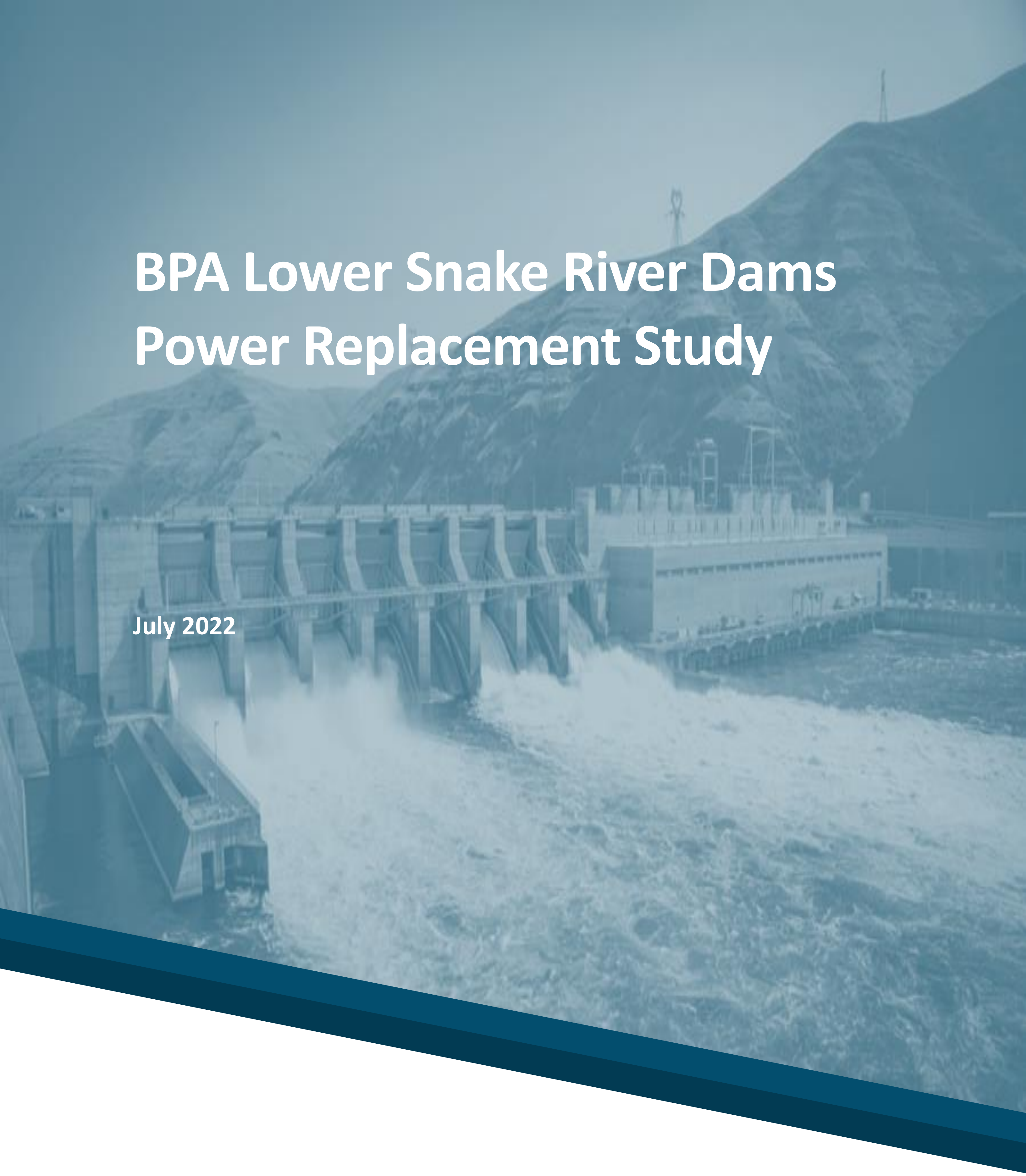
BPA Lower Snake River Dams Power Replacement Study

July 2022



Energy+Environmental Economics

BPA Lower Snake River Dams Power Replacement Study

July 2022

Energy and Environmental Economics, Inc. (E3)
44 Montgomery Street, Suite 1500
San Francisco, CA 94104

415.391.5100

www.ethree.com

Project Team:

Arne Olson

Aaron Burdick

Dr. Angineh Zohrabian

Sierra Spencer

Sam Kramer

Jack Moore

Table of Contents

Table of Figures

Table of Tables

Acronym Definitions

Acronym	Definition
BPA	Bonneville Power Administration
BTM Solar	Behind-the-meter Solar
CA	California
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CES	Clean Energy Standard
CRSO EIS	Columbia River System Operations Environmental Impact Statement
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
ELCC	Effective load carrying capability
HDV	Heavy-duty vehicles
H2	Hydrogen
LDV	Light-duty vehicles
LSR	Lower Snake River
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NV	Nevada
NW	Northwest
PNUCC	Pacific Northwest Utilities Conference Committee
PRM	Planning Reserve Margin
RM	Rocky Mountains
RPS	Renewable Energy Standard
SMR	Small modular reactor
SW	Southwest
WECC	Western Electricity Coordinating Council

Executive Summary

E3 was contracted by the Bonneville Power Administration to conduct an independent study of the value of the lower Snake River dams ("LSR dams") to the Northwest power system. The dams provide approximately 3,500 megawatts ("MW") of total capacity[1] and approximately 2,300 MW of firm peaking capability[2] to support regional reliability. They also generate approximately 900 average MW of zero-carbon energy each year[3], provide essential grid services such as operating reserves and voltage support, and operational flexibility to support renewable integration. If the dams are breached, these power services will need to be replaced to ensure the Northwest power system can continue to provide reliable electricity service. Replacing the dams is complicated by the clean energy policies adopted either statutorily or voluntarily by jurisdictions and utilities throughout the region, which will necessitate a transformation of the power system over time toward non-emitting resources even as electricity demand grows substantially due to electrification of the transportation and building sectors.

This study uses E3's Northwest RESOLVE model to study optimal capacity expansion scenarios with and without the lower Snake River dams, to determine the replacement resources and cost impacts to replace the dams' power output. RESOLVE is an optimal capacity expansion and dispatch model that determines a least-cost set of investment and operational strategies to enable the "Core Northwest" region – consisting of Washington, Oregon, Northern Idaho, and Western Montana – to achieve its long-term clean energy policy goals at least-cost, while ensuring resource adequacy and operational reliability. RESOLVE has been used in several prior studies of electricity sector decarbonization in the Pacific Northwest[4]. Using RESOLVE allows for a dynamic optimization that considers replacement resource needs in the context of long-term system load and policy drivers, not just the near-term resource mix and needs of the system today. The dams are assumed to be breached in 2032, except for one sensitivity that considered 2024 breaching.

---

[1] Hydro traditionally operates above nameplate and closer to overload capacity (~15% above nameplate) and FERC uses these peak generation values in hydro licensing. The "total capacity" refers to the overload capacity, not the nameplate capacity. Historical peak generation was 3,431 MW.

[2] LSR dam firm capacity contributions are estimated using the PNUCC regional hydropower 65% capacity value, which was validated by looking at LSR Dam wintertime power and reserve provision during low hydro conditions. Additionally, E3 considered estimates on the impact of a lower firm capacity value in the results chapter.

[3] The data for the LSR dams was adjusted to reflect the Preferred Alternative operations defined in the Columbia River Systems Operation Environmental Impact Statement (CRSO EIS). E3's RESOLVE model uses 2001, 2005, and 2011 hydro years, which resulted in ~700 average MW of lower Snake River dams generation, making it a conservative estimate of the dams' GHG-free energy value.

[4] Pacific Northwest Low Carbon Scenario Analysis, December 2017, https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/; Pacific Northwest Zero-Emitting Resources Study, January 2020, https://www.ethree.com/e3-examines-role-of-nuclear-power-in-a-deeply-decarbonized-pacific-northwest/

This study's scenario design focuses on three key variables – clean energy policy, load growth, and emerging technology availability – that impact the cost to replace the dams. The scenarios and key assumptions are show in Table 1.

Table 1. Scenario Design

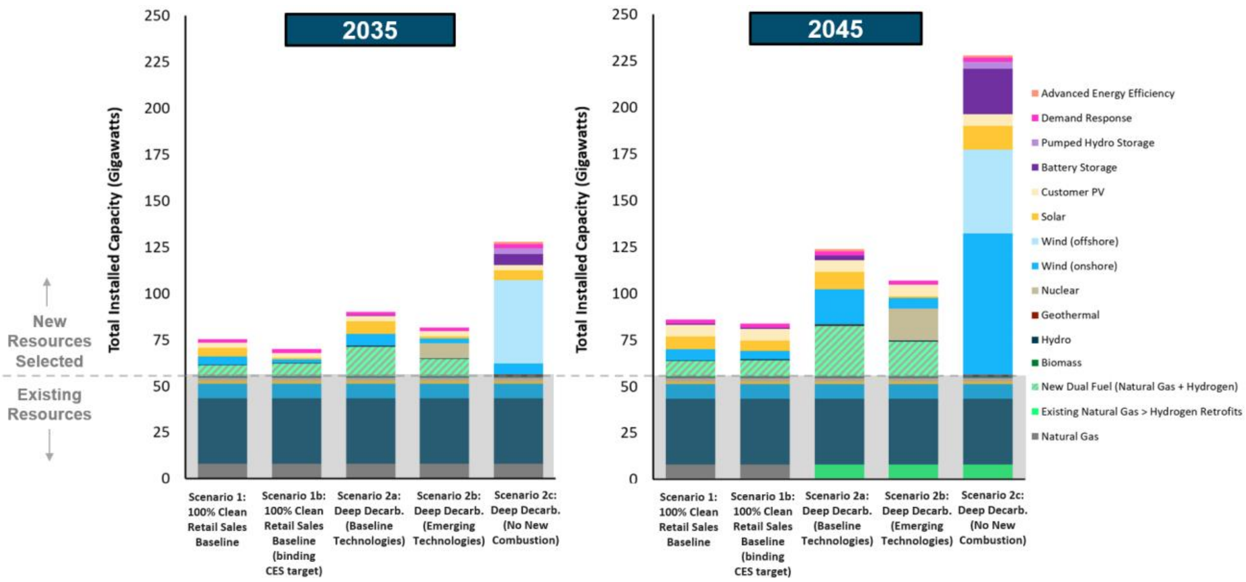
Scenario	Clean Energy Policy	Load Growth	Technology Availability
1 100% Clean Retail Sales	100% retail sales (65-85% carbon reduction)	8th Power Plan Baseline	Baseline (incl. natural gas / hydrogen dual fuel plants)
2a Deep Decarbonization (Baseline Tech.)	100% carbon reduction	High Electrification	Baseline
2b Deep Decarbonization (Emerging Tech.)	100% carbon reduction	High Electrification	Baseline + offshore wind, gas w/ CCS, nuclear SMR
2c Deep Decarbonization (No New Combustion)	100% carbon reduction	High Electrification	Baseline (excluding natural gas / hydrogen dual fuel plants

Even with the dams in place, the region's clean energy goals and potential electrification load growth drive a significant need for new resources. In all scenarios, significant energy efficiency and customer solar is embedded into the load forecast, based on the NWPCC's 8th Power Plan. Additionally, 6 gigawatts ("GW" or 6,000 MW) of coal capacity is retired by 2030, while increasing carbon prices incent further clean energy resource additions. In Scenario 1, the regional power system is required to meet a goal of generating enough clean energy to provide 100% of retail electricity sales, on an average basis over a calendar year. This requires an additional 5.5-7 GW of solar and 4.6-6 GW of wind by 2045 to achieve the clean energy goal; 0.6 GW of battery storage, 2 GW of demand response, and 9 GW of dual fuel natural gas + hydrogen combustion plants are also added to meet the region's resource adequacy needs.[5]

Though all scenarios require more "firm" resources – resources that can start when needed and operate for as long as needed – to meet peak loads, these resources are in higher demand in Scenario 2, in which all greenhouse gas emissions are eliminated from the regional power system by 2045. This scenario also assumes that electrification results in much higher electric loads, particularly in wintertime due to electrification of natural gas space heating in buildings. The baseline scenario (2a) selects additional wind, solar, and geothermal to meet clean energy needs as well as demand response, some battery storage, and 27 GW natural gas and hydrogen dual fuel combustion plants to meet reliability needs. An alternative "emerging technology" scenario selects 17 GW of advanced nuclear technology (small modular reactors or "SMRs") by 2045, in place of the firm capacity provided by natural gas generators while reducing the required quantities of wind, solar and batteries that are needed. The "no new combustion" scenario does not allow clean firm technologies such as hydrogen combustion turbines, gas generation with carbon capture and sequestration (CCS) or SMRs. As a result, it requires impractically high levels of additional onshore wind, offshore wind, and battery storage to meet firm capacity and carbon reduction needs, quadrupling the total installed MW of the Northwest grid by 2045.

[5] E3 ran two versions of scenario 1. In scenario 1, the high carbon price assumed drives the region higher than the 100% CES target, making it a non-binding constraint in the model. In scenario 1b, the 100% CES target is binding in 2045, causing the need to fully replace the GHG-free energy output of the LSR dams. The values shown here represent the range of additions across both scenarios.

Figure 1. Northwest Installed Capacity Mix in Scenarios with the Lower Snake River Dams



When the power services provided by the dams are removed from the regional power system, RESOLVE selects an optimal, i.e., least-cost portfolio of replacement resources that meets the Northwest's clean energy and system reliability needs. These replacement resources require a large investment and come at a substantial cost that increase over time as the region's clean energy goals become more stringent. In the latter years, the replacement costs are highly dependent on scenario-specific assumptions about the availability of emerging technologies. RESOLVE primarily replaces the carbon-free energy from the dams with additional wind and solar power and the firm capacity with dual fuel natural gas and hydrogen combustion plants. Small amounts of additional energy efficiency and battery storage are also selected in some scenarios. By 2045, the dual fuel plants added burn additional hydrogen on low wind days to replace the carbon-free energy provided by the dams. Scenario 2b selects additional nuclear SMRs in lieu of some of the wind and gas resources. Scenario 2c disallows the new combustion plants, even those that would burn green hydrogen, and other emerging technologies, requiring a very large buildout of wind and solar power to replace both the firm capacity and the carbon-free energy of the dams.

The long-term emissions impact of removing the generation of the lower Snake River dams will depend on the implementation of the Oregon and Washington electric clean energy policies. Both a 100% clean retail sales and a zero-carbon emissions target require replacement of most or all of the LSR dams' GHG-free energy. However, without additional earlier carbon-free resource investments beyond those modeled in this study to meet clean energy policy trajectories, carbon emissions may increase initially when the dams are breached, before declining by 2045 as the carbon policy becomes more stringent.

Table 2. Summary of LSR Dams Replacement Resources and Cost Impacts (costs in the table below and throughout this report are shown in real 2022 dollars)

Scenario	Replacement Resources Selected, Cumulative by 2045 (GW)	NPV Replacement Costs[6]	Annual Replacement Costs[7]			Public Power Rate Impact[8]
			2025	2035	2045	2045
Scenario 1: 100% Clean Retail Sales	+ 2.1 GW dual fuel NG/H2 CCGT + 0.5 GW wind	$12.4 Billion	-	$434 million/yr	$478 million/yr	0.8 ₵/kWh [+9%]
Scenario 1: 100% Clean Retail Sales (2024 dam removal)	+ 2.1 GW dual fuel NG/H2 CCGT + 0.5 GW wind	$12.8 Billion	$495 million/yr	$466 million/yr	$509 million/yr	0.8 ₵/kWh [+9%]
Scenario 1b: 100% Clean Retail Sales (binding CES target)	+ 1.8 GW dual fuel NG/H2 CCGT + 1.3 GW solar + 1.2 GW wind	$12.0 Billion	-	$445 million/yr	$473 million/yr	0.8 ₵/kWh [+9%]
Scenario 2a: Deep Decarbonization (Baseline Technologies)	+ 2.0 GW dual fuel NG/H2 CCGT + 0.3 GW li-ion battery + 0.4 GW wind + 0.05 GW advanced EE + 1.2 TWh H2-fueled generation	$19.6 Billion	-	$496 million/yr	$860 million/yr	1.5 ₵/kWh [+18%]
Scenario 2b: Deep Decarbonization (Emerging Technologies)	+ 1.5 GW dual fuel NG/H2 CCGT + 0.7 GW nuclear SMR	$11.2 Billion	-	$415 million/yr	$428 million/yr	0.7 ₵/kWh [+8%]
Scenario 2c: Deep Decarbonization (No New Combustion)	+ 10.6 GW wind + 1.4 GW solar	$42 – 77 billion[9]	-	$ 1,045 – 1,953 million/yr	$1,711 – 3,199 million/yr	2.9 – 5.5 ₵/kWh [+ 34 – 65%]

KEY FINDINGS:

+ ***Replacing the four lower Snake River dams while meeting clean energy goals and system reliability is possible but comes at a substantial cost***, even assuming emerging technologies are available:
    - Requires 2,300 – 4,300 MW of replacement resources
    - An annual cost of $415 million – $860 million by 2045
    - Total net present value cost of $11.2-19.6 billion based on 3% discounting over a 50-year time horizon following the date of breaching
    - Increase in costs for public power customers of $100 – 230 per household per year (an 8 – 18% increase) by 2045

---

[6] These NPV values are calculated assuming a 3% discount rate to represent the public power cost of capital, discounting 50-year of costs starting from the year of breaching (either 2032 or 2024).

[7] Replacement resource costs are calculated assuming project financing per E3's pro forma calculator, rather than assuming upfront congressional appropriation.

[8] This assumes that the annual replacement costs will be borne by BPA's Tier I public power customers. Percentage changes are shown relative to today's average OR + WA retail rate of ~8.5 ₵/kWh.

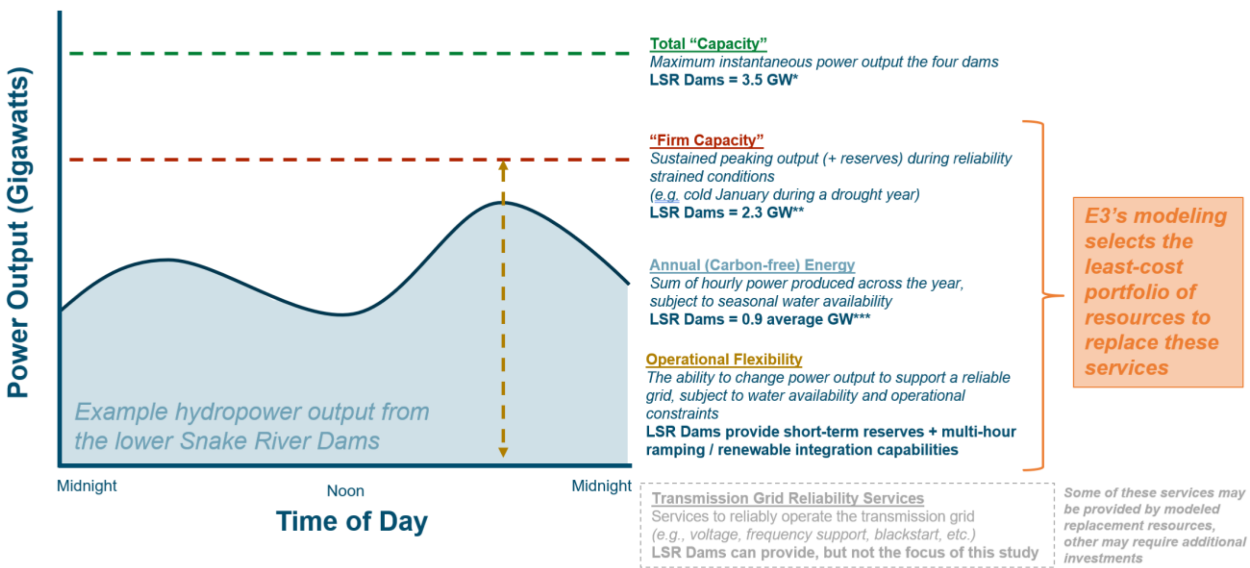
[9] A range of costs was developed for this scenario based on the assumed transmission needs for renewable additions. High end assumes 100% of nameplate, low end assumes 25% of nameplate (approx. marginal ELCC of renewable additions). Low end represents a higher ratio of renewable capacity to transmission capacity, recognizing that much of the additional energy added by 2045 would be curtailed due to over-supply.

- The biggest cost drivers for replacement resources are the need to replace the lost ***firm capacity for regional resource adequacy*** and the need to replace the lost ***zero-carbon energy***
- Replacement becomes ***more costly over time*** due to increasingly stringent clean energy standards and electrification-driven load growth
- ***Emerging technologies*** such as hydrogen, advanced nuclear, and carbon capture ***can limit the cost of replacement resources*** to meet a zero emissions electric system, but the pace of their commercialization is highly uncertain
    - In economy-wide deep decarbonization scenarios, ***replacement without any emerging technologies requires very large renewable resource additions at a very high cost*** (12 GW of wind and solar at $42 – 77 billion NPV cost)

Background

E3 was contracted by the Bonneville Power Administration to conduct an independent study of the value of the lower Snake River dams ("LSR dams") to the Northwest power system. The dams provide approximately 3,500 megawatts ("MW") of total capacity[10] and approximately 2,300 MW of firm peaking capability[11] to support regional reliability. They also generate approximately 900 average MW of zero-carbon energy each year, provide essential grid services such as operating reserves and voltage support, and operational flexibility to support renewable integration. Figure 2 shows the power services that are the focus of this study and those that are out of scope.

Figure 2. Power Services Considered for Replacement in this Study



* Hydro traditionally operates above nameplate and closer to overload capacity (~15% above nameplate) and FERC uses these peak generation values in hydro licensing. Historical peak generation was 3,431 MW.

** Firm capacity assumed in this study is consistent with the ~65% Northwest hydro capacity value assumed by PNUCC (the Pacific Northwest Utilities Conference Committee).

*** Average GW means that on average across an average year the plant generated at 0.9 GW, though its hourly output may be above or below that amount. The data for the LSR dams was adjusted to reflect the Preferred Alternative operations defined in the Columbia River Systems Operation Environmental Impact Statement ("CRSO EIS"). E3's RESOLVE model uses 2001, 2005, and 2011 hydro years, which resulted in ~700 average MW of lower Snake River dams generation, making it a conservative estimate of the dams' GHG-free energy value.

If the dams are breached, these power services will need to be replaced to ensure the Northwest power system can continue to provide reliable electricity service. Replacing the dams is complicated by the clean energy policies adopted either statutorily or voluntarily by jurisdictions and utilities throughout the region,

---

[10] Hydro traditionally operates above nameplate and closer to overload capacity (~15% above nameplate) and FERC uses these peak generation values in hydro licensing. The "total capacity" refers to the overload capacity, not the nameplate capacity. Historical peak generation was 3,431 MW.

[11] LSR dam firm capacity contributions are estimated using the PNUCC regional hydropower 65% capacity value, which was validated by looking at LSR Dam wintertime power and reserve provision during low hydro conditions. Additionally, E3 considered estimates on the impact of a lower firm capacity value in the results chapter.

which will necessitate a transformation of the power system over time toward non-emitting resources even as electricity demand grows substantially due to electrification of the transportation and building sectors.

This study uses E3's Northwest RESOLVE model to study optimal capacity expansion scenarios with and without the lower Snake River dams, to determine the replacement resources and cost impacts to replace the dams' power output. RESOLVE is an optimal capacity expansion and dispatch model that determines a least-cost set of investment and operational strategies to enable the "Core Northwest" region – consisting of Washington, Oregon, Northern Idaho and Western Montana – to achieve its long-term clean energy policy goals at least-cost, while ensuring resource adequacy and operational reliability. RESOLVE has been used in several prior studies of electricity sector decarbonization in the Pacific Northwest[12]. Using RESOLVE allows for a dynamic optimization that considers replacement resource needs in the context of long-term system load and policy drivers, not just the near-term resource mix and needs of the system today. The dams are assumed to be breached in 2032, except for one sensitivity that considered 2024 breaching.[13]

Key Study Questions:

- What **additional resources** would be needed to replace the power services provided by the LSR Dams through 2045?
- What is the **net cost to** BPA ratepayers?
- How do costs and resource needs change under **different types of clean energy futures**?
- How much does replacing the dams rely on **emerging, not-yet-commercialized technologies**?

This study builds off previous LSR dams replacement analysis by using a least-cost optimization-based modeling framework to replace the dams' power services. This optimization ensures that the region meets its aggressive clean energy policy goals, including both decarbonization of electricity as well as high electrification load growth consistent with economy-wide decarbonization goals set by Oregon and Washington.

The other key component of the optimization is maintaining resource adequacy for the region to ensure a reliable electricity supply to existing and any newly electrified loads. This is done using a planning reserve margin constraint and counting non-firm resources like solar, wind, battery storage, pumped hydro storage, and demand response at their effective load carrying capability ("ELCC"), based on E3's prior detailed loss of load probability modeling of the Northwest region.[14]

---

[12] Pacific Northwest Low Carbon Scenario Analysis, December 2017, https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/; Pacific Northwest Zero-Emitting Resources Study, January 2020, https://www.ethree.com/e3-examines-role-of-nuclear-power-in-a-deeply-decarbonized-pacific-northwest/

[13] The study examines LSRD breaching in 10 years (2032) and in 2 years (2024), based on with the approach used in the CRSO EIS.

[14] Resource Adequacy in the Pacific Northwest, March 2019, https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

This modeling framework ensures that when the LSR dams are removed from the Northwest power system, a least-cost replacement mix of new investments and operational changes is found. Through the constraints of the optimization, this least-cost replacement mix meets the same clean energy policy and level of reliability as a system with the LSR dams still intact. This dynamic approach considers replacement resource needs in the context of the evolving long-term system load and policy drivers, not just the near-term resource mix and needs of the system today. It recognizes that significant levels of new renewable energy and other resources are already needed to meet long-term regional needs, ensuring that the replacement resource mix selected is incremental to the long-term buildout, not just an interim solution before clean energy policies reach their apex in the 2040s.

Scenario Design

Regional Policy Landscape

To properly understand the resources needed to replace the power services of the lower Snake River dams, it is critical to consider the regional policy landscape of the Pacific Northwest. In the last few years, the states of Oregon and Washington have adopted some of the most aggressive clean energy policies in the nation. While the Pacific Northwest was already a leader in renewable energy production due to its abundant hydropower resource, these aggressive policies will require key changes to the region. First, coal power must be phased out in the Northwest during this decade and, at least in Washington, carbon will be priced via a market-based cap-and-trade mechanism[15]. Second, additional zero-carbon generation must be added to replace that coal power and to displace remaining emissions from natural gas resources whose firm capacity may still be needed by the region, but which will operate less over time as electric carbon emissions are reduced. Ultimately, to reach a zero-carbon system, those natural gas plants must retire, be converted to zero-carbon fuels (such as green hydrogen), or their emissions be offset in some other manner. Third, economy-wide carbon reduction goals will drive the transformation of the Northwest transportation, building, and industrial sectors, with the general expectation of significant electric load growth in annual energy and peak demand. Key policies in the Northwest and California are summarized in Table 3.

Table 3. Policy landscape in Washington, Oregon, and California

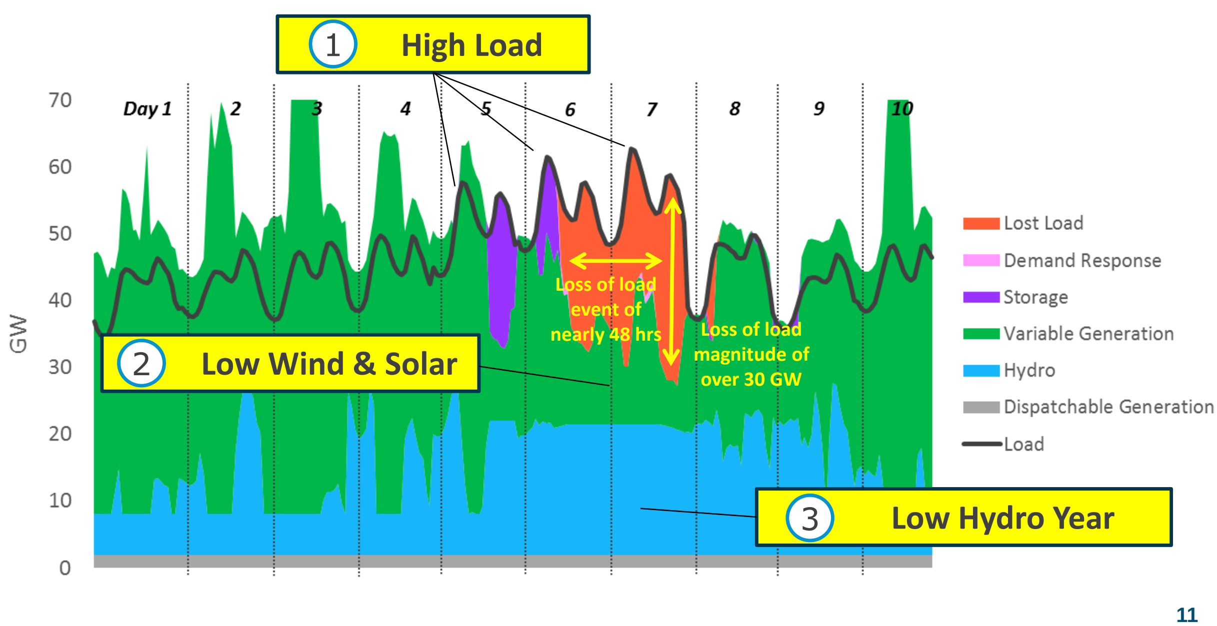
	RPS or Clean Energy Standard?	Coal Prohibition?	Cap-and-Trade?	New Gas?	Economy-Wide Carbon Reduction?
WA	✓ Carbon neutral by 2030, 100% carbon free electricity by 2045	✓ Eliminate by 2025	✓ Cap-and-invest program established in 2021, SCC in utility planning	✓	✓ 95% GHG emission reduction below 1990 levels and achieve net zero emissions by 2050
OR	✓ 50% RPS by 2040, 100% GHG emission reduction by 2040, relative to 2010 levels	✓ Eliminate by 2030	✓ Climate Protection Plan adopted by DEQ in 2021 (power sector not included)	✕ HB 2021 bans expansion or construction of power plants that burn fossil fuels	✓ 90% GHG emission reduction from fossil fuel usage relative to 2022 baseline
CA	✓ 60% RPS by 2030, 100% clean energy by 2045	✓ Coal-fired electricity generation already phased out	✓	✕ CPUC IRP did not allow in recent procurement order	✓ 40% GHG emission reduction below 1990 levels by 2030 and 80% by 2050

[15] For simplicity, this study assumes a uniform carbon price across the Core Northwest region beginning in 2023.

Maintaining Resource Adequacy in Low-carbon Grids

Like other regions pursuing aggressive climate policies, the Northwest faces a key decarbonization challenge: how to maintain a reliable electricity supply, while simultaneously increasing electric loads and retiring the firm, but emitting, capacity that currently supports regional reliability. In 2019, E3 used its RECAP loss of load probability model to study how decarbonizing the electricity supply impacts regional reliability.[16] This study found that clean energy resources such as solar, wind, batteries, and demand response can each provide a certain amount of reliable capacity and that combinations of them can provide even more by capturing "diversity benefits" (such as solar shifting the reliability risk into evening hours when wind output is higher). However, these resources also have limits to the amount of reliable capacity they can provide, and their contributions decline as more of them are added (the decline in capacity contributions of these resources is known as "saturation effects"). Figure 3 shows a graph from E3's 2019 study that illustrates the key drivers of reliability in a decarbonized grid: high load, low renewables, and low hydro conditions. Unlike a summer peaking *capacity constrained* system like the desert southwest, these conditions make it particularly challenging for battery storage to replace the Northwest's firm capacity resources, since batteries are unable to charge during *energy constrained* periods of low renewable energy and low hydro availability. The study concluded therefore that additional firm generating capacity may be needed, even in scenarios that add significant amounts of non-firm solar, wind, batteries, and demand response. The resource adequacy modeling approach is described further in the section *Resource Adequacy Needs and Resource Contributions*.

Figure 3. Key Drivers of Pacific Northwest Reliability Events in a Decarbonized Grid



[16] E3, 2019. *Resource Adequacy in the Pacific Northwest.* https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

Since the 2019 study, “emerging” technologies are increasingly seen as potentially viable options to reduce all of the carbon emissions in the Northwest. “Clean firm” resources like green hydrogen, gas with carbon capture and storage, and nuclear small modular reactors provide the firm capacity necessary to backup renewable resources and can provide the zero-carbon energy needed on low renewable days to operate a zero-carbon grid. While their costs and commercialization trajectories remain uncertain, this LSR dams replacement study considers various scenarios of their availability.

Table 4. Summary of Resource Adequacy Capacity Contributions of LSR Dam Replacement Resource Options

Replacement Resource Option	RA Capacity Contributions
Battery storage	Sharply declining ELCCs[17]
Pumped storage	Sharply declining ELCCs
Solar	Declining ELCCs
Wind	Declining ELCCs
Demand Response	Declining ELCCs
Energy Efficiency	Limited potential vs. cost
Small Hydro	Limited potential
Geothermal	Limited potential
Natural gas to H2 retrofits	Clean firm, but not fully commercialized
New dual fuel natural gas + H2 plants	Clean firm, but not fully commercialized
New H2 only plants	Clean firm, but not fully commercialized
Gas w/ 90-100% carbon capture + storage	Clean firm, but not fully commercialized
Nuclear Small Modular Reactors	Clean firm, but not fully commercialized

Scenarios Modeled

This study focuses on three key variables (clean energy policy, load growth, and emerging technology availability) that impact the cost to replace the dams.

Clean Energy Policy

Clean energy policy for the electric sector is modeled at either 100% clean retail sales or zero-carbon by 2045. A 100% clean retail sales policy requires serving 100% of electricity sold on an annual basis to be met by clean energy resources. This allows generation not used to serve retail sales (i.e., transmission and distribution losses) to be met by emitting resources. It also allows emitting generation or unspecified

[17] E3 performed a sensitivity with battery ELCCs that do not decline so sharply. This sensitivity shows minor changes in the LSR dam replacement resources, but little to no change in the replacement costs.

imports in one hour to be offset by exported generation in another hour of the year. In the baseline load scenario, reaching 100% clean retail sales by 2045 results in ~65-85% carbon reduction compared to 1990 levels. The zero-carbon scenario ensures that all electricity generated in the Northwest or imported from other regions emits no carbon emissions in every hour of the year.

Load Growth

With aggressive clean energy policies, load growth determines the amount of new zero-emitting resources that must be added to the Northwest power system. A baseline load growth scenario is modeled, based on the forecast in the NWPCC 8th Power Plan. A second high electrification scenario is developed based on the high electrification case in the Washington State Energy Strategy.[18] Based on E3's analysis of the electrification of transportation, buildings, and industry in that study, this scenario results in an additional annual energy demand increase of 28% by 2045 (above the baseline scenario) and an additional winter peak demand increase of 68%. The peak demand increase is high due to the electrification of space heating end uses, which requires replacing the significant quantities of energy provided by the natural gas system during extreme wintertime cold weather events with electricity.

Technology Availability

It is expected that the availability of emerging technologies may be critically important for replacing the LSR dam power services while reaching a deeply decarbonized grid. All scenarios include "mature technologies" such as solar, wind, battery storage, pumped hydro storage, demand response, energy efficiency, small hydro, and geothermal. Three scenarios of emerging technology availability are developed as follows:

A. **Baseline technologies**: mature technologies and dual fuel natural gas + hydrogen combustion plants
B. **Emerging technologies**: mature technologies, dual fuel natural gas + hydrogen combustion plants, small modular nuclear reactors, natural gas with carbon capture and storage, and floating offshore wind
C. **No new combustion (limited technologies)**: mature technologies and floating offshore wind

All scenarios assume that the existing natural gas capacity fleet can convert to green hydrogen, i.e., hydrogen produced using zero-carbon electricity. However, new firm resources are needed in all scenarios to replace retiring resources and meet growing electric loads.

Table 5 shows a summary of the four scenarios that are the primary focus of this study.

---

[18] See Washington State's *2021 State Energy Strategy,* https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/

Table 5. Scenario Design

Scenario	Clean Energy Policy	Load Growth	Technology Availability
1 100% Clean Retail Sales	100% retail sales (65-85% carbon reduction)	8th Power Plan Baseline	Baseline (incl. natural gas / hydrogen dual fuel plants)
2a Deep Decarbonization (Baseline Tech.)	100% carbon reduction	High Electrification	Baseline
2b Deep Decarbonization (Emerging Tech.)	100% carbon reduction	High Electrification	Baseline + offshore wind, gas w/ CCS, nuclear SMR
2c Deep Decarbonization (No New Combustion)	100% carbon reduction	High Electrification	Baseline (excluding natural gas / hydrogen dual fuel plants)

The following additional sensitivities were considered:

- **Scenario 1: 100% Clean Retail Sales (2024 dam removal)**: same as scenario 1, but with 2024 LSR Dams breaching instead of 2032.
- **Scenario 1b 100% Clean Retail Sales (Binding CES Target)**: E3 ran two versions of scenario 1. In scenario 1, the high carbon price assumed drives the region higher than the 100% CES target, making it a non-binding constraint in the model. In scenario 1b, no carbon price was assumed and the 100% CES target is binding in 2045, causing the need to fully replace the GHG-free energy output of the LSR dams.
- **High Storage ELCC Sensitivity**: sensitivities were run on both Scenarios 1 and 2a to test whether a higher Northwest storage ELCC would change the marginal resources and replacement costs for the LSR dams.

Modeling Approach

RESOLVE Model

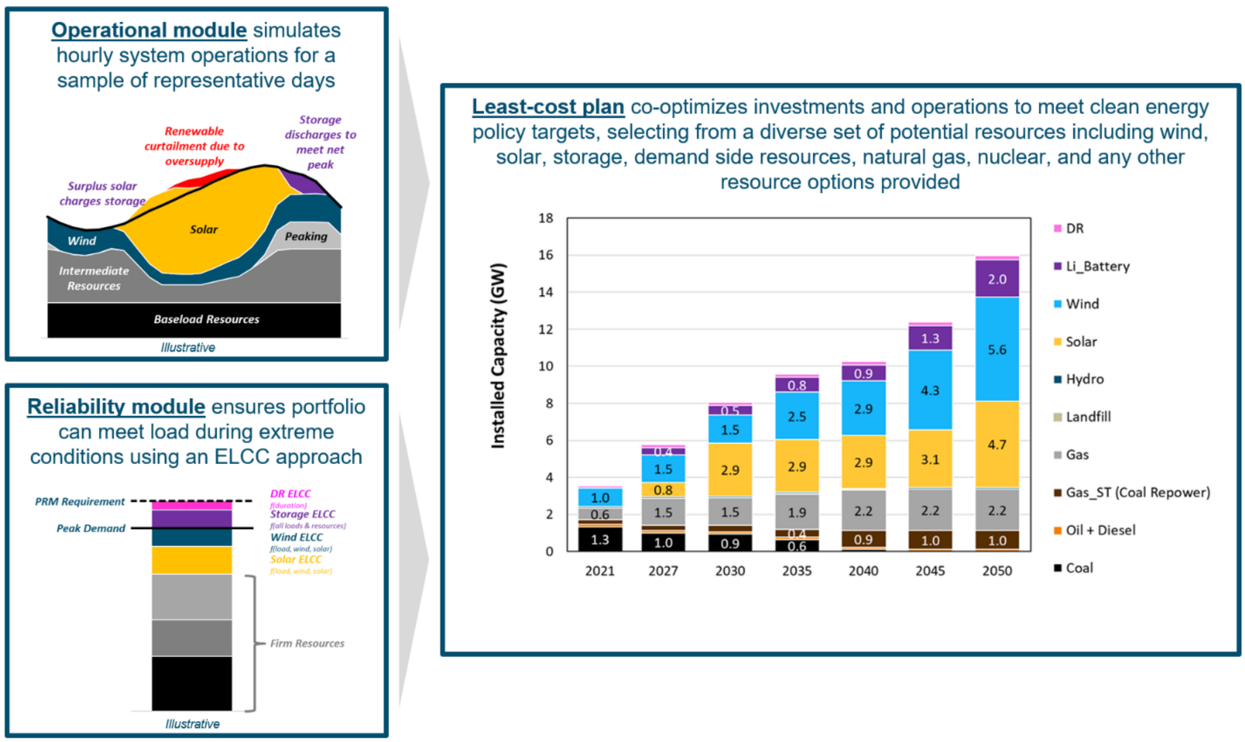
E3's Renewable Energy Solutions Model (RESOLVE) is used to perform a portfolio optimization of Northwest system's electric generating resource needs between 2025 and 2045. RESOLVE is an optimal capacity expansion and dispatch model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, operational, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable energy 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.

The three primary drivers of optimized resource portfolios include:

+ **Reliability:** all portfolios ensure system meets resource adequacy requirements. In this case, the target reliability need is to meet 1-in-2 system peak plus additional 15% of planning reserve margin (PRM) requirement.
+ **Clean Energy Standard ("CES") and/or carbon reduction targets:** all portfolios meet the clean energy standard and/or a carbon-reduction trajectory
+ **Least cost**: the model's optimization develops a portfolio that minimizes costs

Figure 4 illustrates the use of RESOLVE's operational module, which tracks hourly system operations including cost and greenhouse gas emissions across a representative set of days, and RESOLVE's reliability module, that uses exogenously calculated input parameters to characterize system reliability of candidate portfolios using effective load carrying capability (ELCC) for solar and wind resources.

Figure 4. Schematic Representation of the RESOLVE Model Functionality



RESOLVE develops least-cost portfolios using key inputs and assumptions including loads, existing resources, new resource options, retirement or repowering resource options, resource costs, resource operating characteristics including resource adequacy contributions, a zonal transmission transfer topology, and new resource transmission costs.

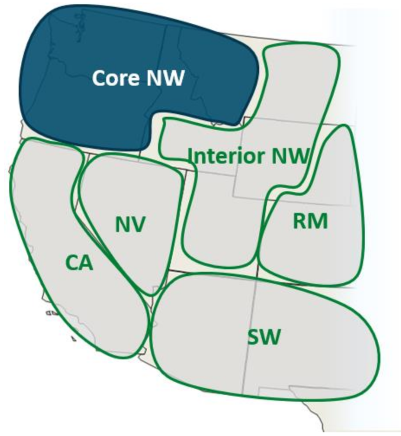
Northwest RESOLVE Model

The Northwest RESOLVE model was developed in 2017 for E3's *Pacific Northwest Low Carbon Scenario Analysis* study.[19] It uses a zonal transmission topology to simulate flows among the various regions in the Western Interconnection. In this study, RESOLVE is designed to include 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 (see Figure 5). This study focuses on the Core Northwest region as the "Primary Zone"—the zone for which RESOLVE makes resource investment decisions. This zone covers Washington, Oregon, Northern Idaho and Western Montana. The remaining balancing authorities outside of the Core Northwest are grouped into five additional zones: (1) Other Northwest, (2) California, (3) Southwest, (4) Nevada and (5) Rockies. For these zones, investments are not optimized; rather, the trajectory of new builds is established based on regional capacity needs to meet PRM targets, as well as renewable needs to comply with existing RPS and GHG policies in their respective regions, and held

[19] Pacific Northwest Low Carbon Scenario Analysis - Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector, 2017. https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

constant across all scenarios. E3's WECC-wide resource mix incorporates aggressive climate policy across the interconnection, as described in section *Baseline resources*.

Figure 5. RESOLVE Northwest zonal representation



The Northwest RESOLVE model simulates the operations of the WECC system for 41 independent days sampled from the historical meteorological record of the period 2007-2009. An optimization algorithm is used to select the 41 days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. Daily hydro conditions are sampled separately from dry (2001), average (2005), and wet (2011) hydro years to provide a complete distribution of potential hydro conditions. This allows RESOLVE to approximate annual operating costs and dynamics while limiting detailed operational simulations of grid operations to 41 days.

LSR Dams Modeling Approach

The LSR dams' capacity and operation are characterized with several input parameters that are presented in Section *Hydro parameters*. The approach taken in this analysis is to model LSR dams as an *in/out* resource to determine the dams' replacement costs and replacement portfolio. In other words, "in" scenarios include LSR dams in the existing resource portfolio of Core Northwest throughout the entire modeling period (i.e., 2025-2045); whereas "out" scenarios exclude LSR dams with preset retirement dates of 2032. An earlier retirement of LSR dams, 2024, is considered in a sensitivity case. The difference between the costs and resource portfolios for in and out cases reveals the value of LSR dams, as shown in Figure 6. Total NPV costs of resources replacing LSR dams are estimated in the year of breaching the dams.[20] NPV replacement costs are calculating using a 3% discount rate to represent the public power cost of capital.

[20] I.e. when the dams are removed in 2032, future costs after 2032 are discounted to the year 2032 to calculate the NPV replacement costs.

Figure 6. Modeling Approach to Calculate the LSR Dams Replacement Resources and Costs

1. ***With the lower Snake River dams*****, optimize long-term resource needs and operations for the Pacific Northwest**
   - Produces necessary resource additions and total system costs and emissions
2. ***Remove the lower Snake River dam generating capacity, then re-optimize*** **long-term resource needs and operations for the Pacific Northwest**
   - Produces a second set of resource additions and total system costs and emissions
   - All scenarios breach the dams in 2032, except for one scenario in 2024
3. ***Calculate additional resources and investment + operational costs*** **required to replace the dams**
   - Calculated as the difference between steps 1 and 2 above

This modeling approach inherently considers the benefits of avoiding the LSR dams ongoing fixed and variable costs. The costs associated with breaching the LSR dams themselves are not included in this study. Other power services (i.e., transmission grid reliability services provided by the dams) are also not included but are summarized qualitatively in the Appendix.

Key Input Assumptions

Load forecast

Base load forecast is from NWPCC 2021 Plan and is adjusted to E3's boundary of Core Northwest which roughly represents 87.5% of load of the Northwest system in the NWPCC 2021 Plan. Additionally, a high electrification scenario is modeled which takes Washington's State Energy Strategy high electrification load, scaled up and benchmarked to the Core Northwest region. The baseline high electrification load trajectories are displayed in Figure 7. It is notable that in the high electrification scenario, electric energy demand grows by about 28% by 2045 across all sectors, most noticeably in the commercial building and transportation sectors, to meet net-zero emissions by 2050. In the commercial and residential space heating sectors, electrification indicates a switch to high electric resistance and heat pump adoption, which will significantly impact load profiles and ultimately peak load. Hourly loads are modeled in RESOLVE by scaling normalized hourly shapes with annual energy forecasts. The normalized shapes are adopted from E3's 2017 study *Pacific Northwest Low Carbon Scenario Analysis.*[21]

[21] Pacific Northwest Low Carbon Scenario Analysis - Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector, 2017. https://www.ethree.com/wp-content/uploads/2018/01/E3_PGP_GHGReductionStudy_2017-12-15_FINAL.pdf

Figure 7. Annual energy load forecasts for Core Northwest

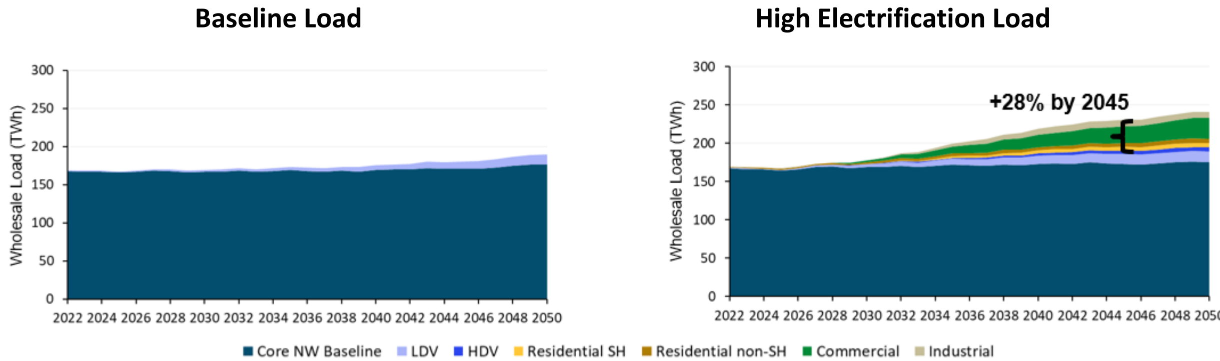
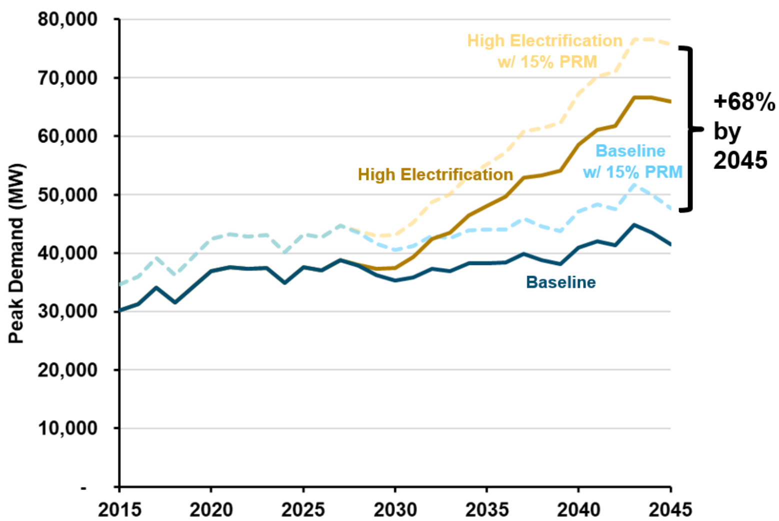


Figure 8 shows the peak demand impacts (including the 15% planning reserve margin) of the high electrification case relative to the baseline, showing a 68% increase by 2045. This high growth is driven by the winter peaking capacity required to replace the gas system peaking capacity to serve peak space heating needs.

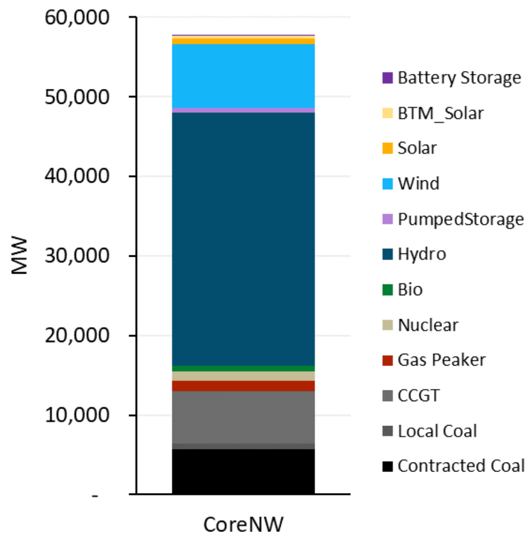
Figure 8. Peak demand forecasts for Core Northwest



Baseline resources

Baseline resources include the existing conventional resources such as natural gas and coal-fired technologies, existing nuclear capacity, hydro as well as pumped storage, battery storage, solar PV, BTM PV and onshore wind technologies. As shown in Figure 9, today's Northwest system has 58 GW capacity. The 1,185 MW nuclear capacity in the Northwest zone remains active throughout the modeling period while the 670 MW local coal capacity is retired by 2025 and the 5,700 MW contracted out of region coal capacity is retired by 2030. The WECC 2020 Anchor Data Set is used for Northwest's existing and planned resources. By 2045, about 5.8 GW additional customer PV is included as planned capacity to capture the growth in behind-the-meter generation forecasted in NWPCC 2021 Power Plan.

Figure 9. Northwest resource capacity in 2022



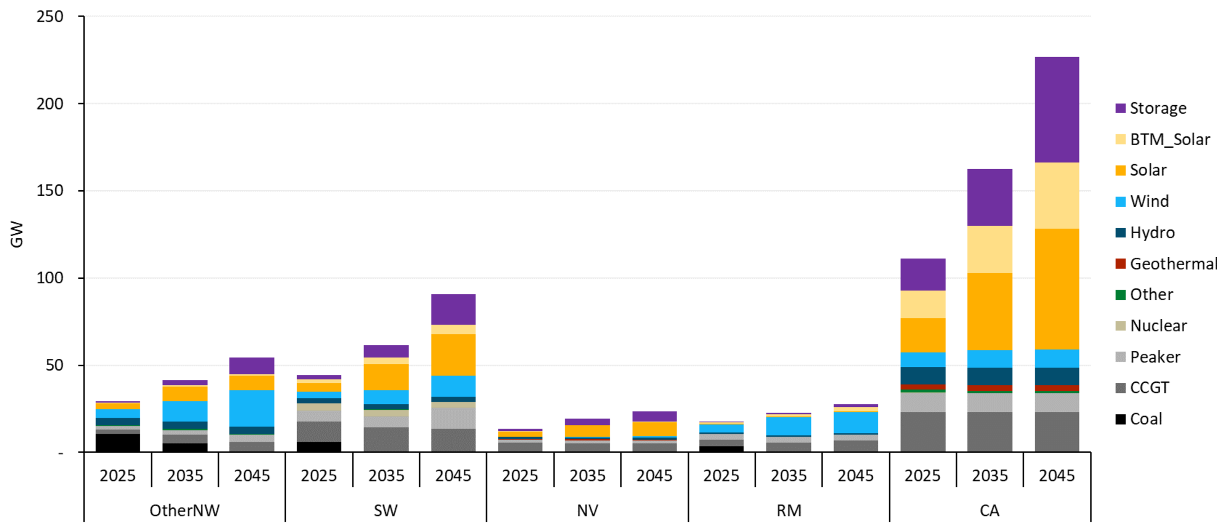
The investment decisions for external zones are pre-determined based on capacity expansion analysis completed by E3 that accounts for policy targets in each zone as summarized in Table 6. The new builds consist of significant increases in solar and battery capacity additions due to the more aggressive RPS targets, assumed electrification, and the decline of technology cost forecasts (see Figure 10). All future builds in these zones include mature technologies but as discussed in the next section, emerging technologies are made available for RESOLVE to optimize the future resource portfolios in the Northwest zone. There is significant solar and battery storage growth in California, the Southwest, and Nevada that generally lower the marginal value of solar energy produced across the WECC.

Table 6. Policy targets for builds in external zones

State	Requirement	Policy	2050 Renewable Target
AZ	40% by 2030; 60% by 2045	Transitions to CES[22]	70%
CA	60% by 2030; 100% by 2045	Transitions to CES	100%
CO	30% by 2020; 50% by 2030, 76% by 2050 (Xcel reaches 100% while other utilities stay at 50%)	Transitions to CES	75%
ID	90% by 2045 (ID Power's announced utility goals)	RPS	90%
MT	87% by 2045 (state carbon reduction goal)	RPS	87%
NM	40% by 2025; 100% by 2045	Transitions to CES	100%
NV	50% by 2030; 100% by 2050	Transitions to CES	95%
UT	50% by 2030; 55% by 2045 (PacifiCorp's IRP)	RPS	55%
WY	50% by 2030, 55% by 2045 (PacifiCorp's IRP)	RPS	55%

[22] CES = "Clean Energy Standard", an annual based clean generation standard.

Figure 10. Total installed capacity for external zones



Candidate resource options, potential, and cost

A wide range of technologies and resources are made available in RESOLVE, including mature and emerging technologies. The list of technologies made available in each modeled scenario is presented in Table 7. Some technologies such as solar and onshore wind are low-cost zero-carbon energy resources with limited resource potential and declining capacity values. Storage resources such as battery storage and pumped hydro support renewable integration but show limited capacity value given the large shares of hydro in the Northwest region. Demand response supports peak reduction but also faces declining ELCCs. Energy efficiency supports energy and peak reduction but increasingly competes against low-cost renewables. Geothermal is relatively high cost and has limited potential but provides highly valuable “clean firm” capacity.

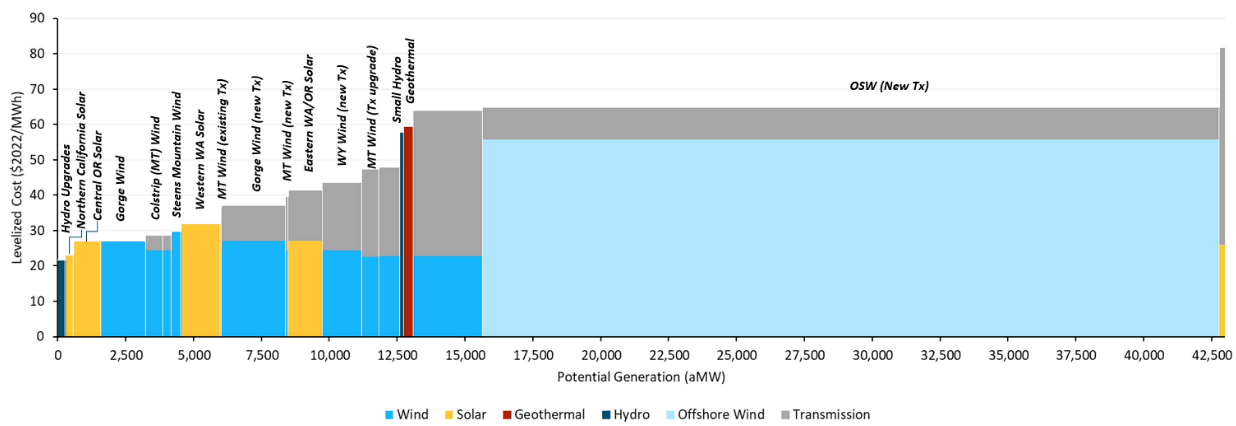
Some emerging technologies are also made available in several scenarios to allow for firm zero-carbon technologies to be selected from. Hydrogen-capable generators such as dual fuel combustion turbines and combined cycles (i.e., capable of burning both natural gas and hydrogen) as well as retrofits of existing gas generators to burn hydrogen are modeled. These technologies provide low-cost capacity options with very high energy cost when burning expensive hydrogen fuel, therefore RESOLVE selects them for firm capacity needs but limits their hydrogen energy production. Natural gas with carbon capture and storage (CCS) technologies are moderately high cost in terms of both energy and capacity. Nuclear SMR provides moderately high capital cost but low operating cost for firm zero-carbon energy generation. This technology is made available to the model after 2035, to account for the time needed for technology development, licensing, and installation. Floating offshore wind is also modeled as an emerging technology which address onshore resource and land constraints but is generally higher cost than onshore wind while providing a similar annual capacity factor to high quality Montana and Wyoming wind.

Table 7. Available technologies in each modeled scenario

Resource	A. Baseline	B. Emerging Tech	C. No New Combustion (Limited Tech)
Mature resources: solar, wind, battery storage, pumped storage, demand response, energy efficiency, small hydro, geothermal	✓	✓	✓
Natural gas to hydrogen retrofits	✓	✓	✓
Dual fuel natural gas + hydrogen plants	✓	✓	×
Natural gas with 90-100% carbon capture and storage	×	✓	×
Nuclear small modular reactors	×	✓	×
Floating offshore wind	×	✓	✓

There are physical limits to the quantity of renewable resources that can be developed in each location; RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio. Moreover, some new resources will need extensive transmission upgrades which are accounted for in the renewable energy supply curve.[23] Figure 11 shows a "supply curve" for renewables in the year 2045, ordered by total generation plus transmission cost. While the quantity of solar and onshore wind energy is limited, offshore wind potential is effectively unlimited in the model although its cost remains high relative to land-based renewables through 2045. It should be noted that RESOLVE doesn't select resources based on their cost alone; it also considers the value these resources provide as part of a regional portfolio. More detail information on technology cost trajectories and data sources can be found in the Appendix.

Figure 11. Renewable resource supply curve in 2045, including transmission cost adders



[23] Note: certain solar resources (i.e., Western WA solar) might require transmission upgrades to bring the supply to load centers, which are not captured.

Clean energy policy targets

RESOLVE enforces a clean energy standard ("CES") requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the CES target in each year. The clean energy standard percentage is calculated as follows, and the target values are summarized in Table 2:

$$CES\ \% = \frac{Annual\ Renewable\ Energy\ or\ Zero\ Emitting\ Generation}{Annual\ CoreNW\ Retail\ Electric\ Sales}$$

Eligible renewable energy and zero-emitting resources include: solar, wind, geothermal, hydropower, nuclear, biomass, green hydrogen, and natural gas with carbon capture and storage.

Regarding GHG emissions, RESOLVE enforces a greenhouse gas constraint on the CoreNW region such that total annual emission generated in the zone must be less than or equal to the emissions cap. The greenhouse gas accounting for the Northwest zone follows the rules established by the California Air Resources Board. The CoreNW carbon emissions baseline is set as 33 MMT at the 1990 level. The total greenhouse gas emissions attributed to the Core Northwest region include:

+ **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 fuel-specific CO_2 emissions intensity;
+ **External resources owned/contracted by Core Northwest utilities:** greenhouse gas emissions emitted by resources located outside the Core Northwest but currently owned or contracted by utilities that serve load within the region, based on fuel burn and fuel-specific CO_2 emissions intensity; and
+ **"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 unspecified flows of power into the region, based on a deemed emissions rate of 0.43 tons/MWh.

Table 8. Annual CES and carbon emissions targets modeled for CoreNW in RESOLVE

Resource	2025	2030	2035	2040	2045
Clean energy standard % (used in Scenarios 1 and 2[24])	29%	49%	68%	88%	100%
Carbon reduction emissions target (used only in Scenario 2)	22.7 MMT	17.0 MMT	11.3 MMT	5.7 MMT	0 MMT

Hydro parameters

RESOLVE characterizes the generation capability of the hydroelectric system by including three types of constraints from actual operational data: (1) daily energy budgets, which limit the amount of hydro generation in a day; (2) maximum and minimum hydro generation levels, which constrain the hourly hydro

---

[24] While a clean energy standard is modeled in scenario 2, the mass-based carbon reduction target constraint is a more binding constraint, pushing the model beyond the minimum CES %'s shown here.

generation; and (3) multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change from one to four hours. Combined, these constraints limit the generation of the hydro fleet to reflect realistic seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system.

In this analysis, hydro operating data are parameterized using conditions for three different hydrological years, i.e., 2001 for dry, 2005 for average and 2011 for wet conditions. For LSR dams, we use hourly generation data provided by BPA, which are adjusted for latest fish protection and spill constraints. For the remainder of the northwest hydro fleet, we rely on historical hydro dispatch data used to develop the TEPPC 2022 Common Case dataset. Using muti-year historical hydro operational data allows capturing the complete set of physical and institutional factors, such as cascading hydro, streamflow constraints, fish protection, navigation, irrigation, and flood control, that limit the amount of flexibility in the hydro system.

For each RESOLVE sampled day, the hydro daily energy budget is calculated as the average of daily electricity generated in the month of each sampled RESOLVE day in its corresponding matched hydro year.[25] The maximum and minimum hydro generation levels (P_{min} and P_{max}) are calculated as the absolute min and max of generation in the month of each sampled RESOLVE day in its corresponding matched year. Multi-hour ramp rates are estimated based on the 99th percentile of upward ramps observed across the three hydrological years of hourly data. In addition, for non-LSR Northwest hydro, the model allows 5% of the hydro energy in each day to be shifted to a different day within two months to capture additional flexibility for day-to-day hydro energy shift.

[25] LSR dams generate about 900 average MW of energy during an average hydro year. However, during the three years modeled in RESOLVE, the LSR dams produced only ~700 average MW generation for LSR dams. This means our estimate of the replacement cost of the dams is quite conservative relative to a longer-term expected average of ~900 MW.

Figure 12. RESOLVE Hydro inputs for LSR Dams and other Northwest hydro

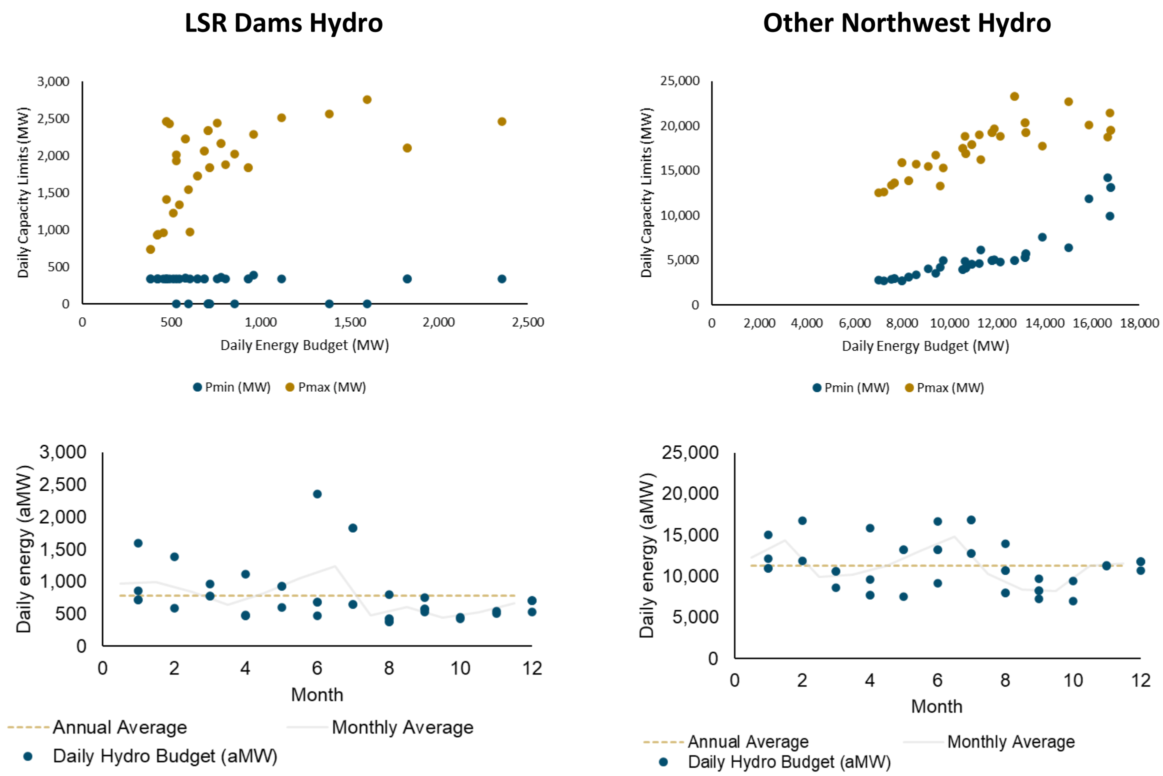


Table 9. Multi-hour ramping constraints applied to Northwest hydro

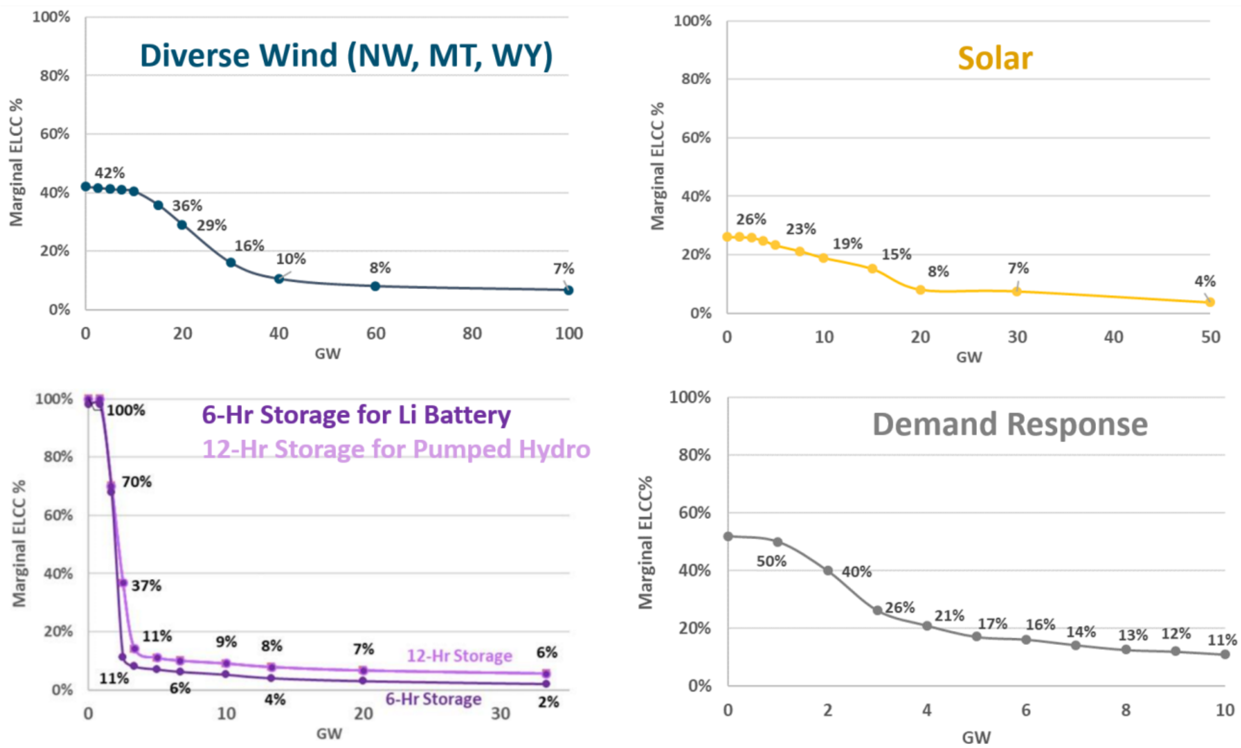
	One hour	Two hours	Three hours	Four hours
LSR Dams Hydro	36%	43%	45%	48%
Other Northwest Hydro	14%	23%	29%	32%

Resource Adequacy Needs and Resource Contributions

Hydro firm capacity contribution for both LSR dams and other Northwest hydro is assumed to be 65% of nameplate, per PNUCC methodology (based on 10-hr sustaining peaking capacity). This means that the LSR dams provide 2,284 MW of firm capacity that must be replaced if the dams are breached. This assumption was validated based on BPA modeled LSR dam performance data during the 2001 dry hydro year, as described in the section *Key Uncertainties for the Value of the Lower Snake River Dams*, which also describes estimates of the NPV impact of assuming a lower firm capacity value for the dams.

Resource adequacy needs are captured in RESOLVE by ensuring that all resource portfolios have enough capacity to meet the peak Core Northwest median peak demand plus a 15% planning reserve margin. Firm capacity resources are counted at their installed capacity. Hydro resources are counted at the 65% regional value used in PNUCC's 2021 resource adequacy analysis. Solar, wind, battery storage, pumped hydro storage, and demand response are counted at their effective load carrying capability ("ELCC") based on E3's RECAP modeling from its 2019 *Resource Adequacy in the Pacific Northwest* study.[26] Figure 13 shows the initial capacity values for these resources, as well as the declining marginal contributions as more of the resource is added. RESOLVE uses these data points to develop tranches of energy storage and demand response resources with declining marginal ELCCs for each tranche. Solar and wind ELCCs are input into RESOLVE using a 2-dimensional ELCC surface that captures the interactive benefits of adding various combinations of solar and wind together. Resources on the surface (such as different wind zones) are scaled in their ELCC based on their capacity factor relative to the base capacity factor assumed in the surface, and the entire surface is scaled as peak demand grows.

Figure 13. Solar, Wind, Storage, and Demand Response Capacity Values



The capacity value for energy storage resources shown in Figure 13 are very different from those in other regions, such as California or the Desert Southwest, declining much more quickly as a function of penetration. There are two reasons for this. First, the Pacific Northwest is a winter peaking region in which loss-of-load events are primarily expected to occur during extreme cold weather events that occur under drought conditions in which the region faces an energy shortfall. These events, such as the one illustrated in Figure 3 above, result in multi-day periods in which there is insufficient energy available to charge storage resources, severely limiting their usefulness. This is unlike the Southwest, where the most stressful system conditions occur on hot summer days in which solar power is expected to be abundant and batteries can recharge on a diurnal cycle. Second, the Pacific Northwest already has a very substantial amount of reservoir storage which can shift energy production on a daily or even weekly basis. Thus, the

[26] Resource Adequacy in the Pacific Northwest, 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

Pacific Northwest is already much closer to the saturation point where additional diurnal energy shifting has limited value.

Nevertheless, recognizing that the capacity value of energy storage is still being researched, in the Northwest and elsewhere, we include a sensitivity case in which energy storage resources are assumed to have much higher ELCC values, similar to what is expected in the Southwest at comparable penetrations. This test case was used to assess whether a higher energy storage ELCC would change the replacement resources and replacement cost of the LSR dams. The results are presented in the section *Replacement Resources Firm Capacity Counting*.

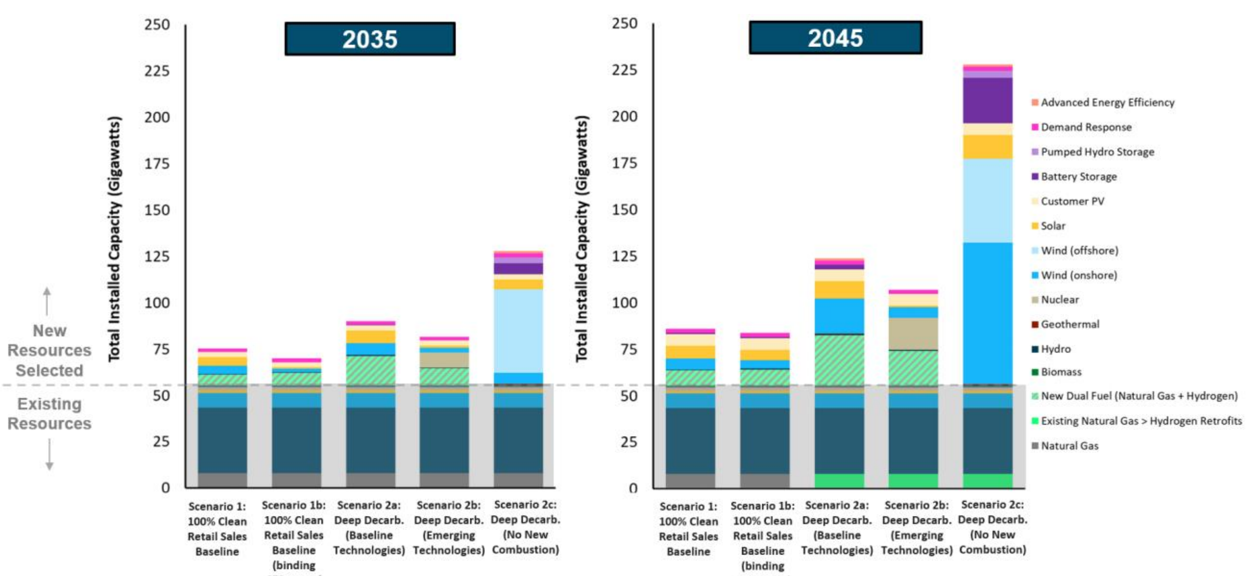
Results

RESOLVE model runs for the 2025-2045 period produce optimal resource portfolios of additions and retirements by resource type, as well as metrics of annual and hourly resource generation, carbon emissions, and total system costs. This section presents the RESOLVE modeling results, focused on the years of 2035 and 2045 to highlight the mid-term and long-term resource needs. Following that, the result of the RESOLVE runs with the LSR dams breached are presented, with the replacement resource and costs to replace the dams' power services.

Electricity Generation Portfolios with the Lower Snake River Dams Intact

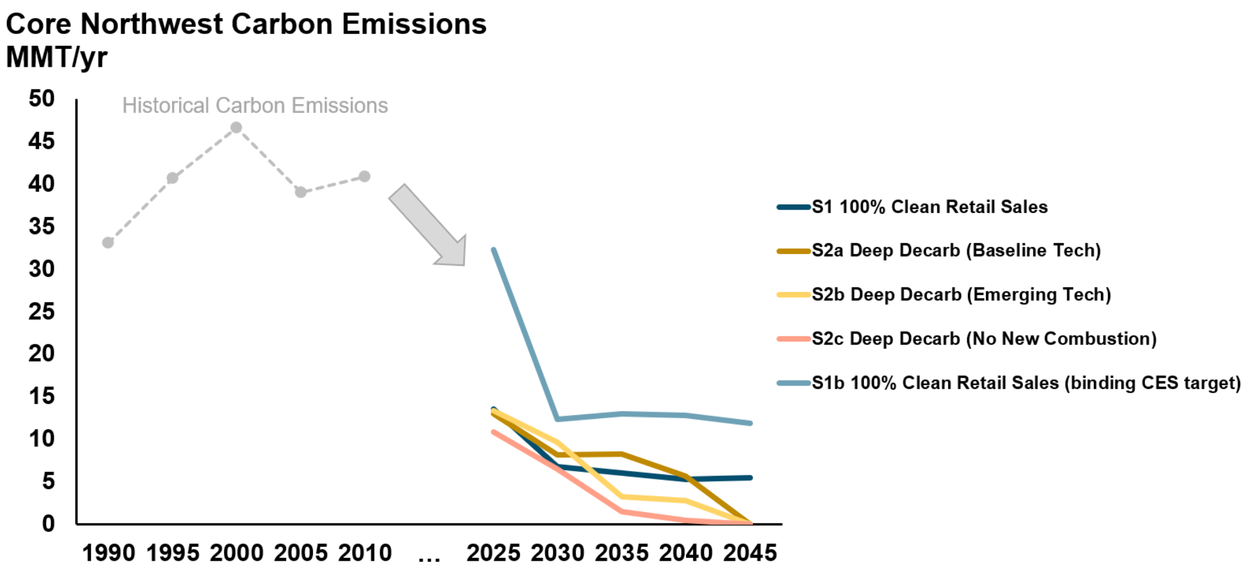
In the scenarios that do not assume breaching of the LSR dams, large amounts of utility-scale solar PV, onshore wind, offshore wind, hydrogen-capable combined cycle, and some amounts of energy efficiency and demand response are selected to meet the growing electricity demand, PRM, and emissions reductions. Electrification load growth along with zero emissions targets drive higher needs in deep decarbonization scenarios (i.e., S2a, S2b and S2c) compared to the reference scenario (S1) in both snapshot years of 2035 and 2045. In S2b, clean firm technologies such as SMR nuclear are selected in place of additional onshore wind, solar and dual-fuel CCGT selected in S2a. In the absence of clean firm technologies (no new combustion) in S2c, massive amounts of offshore wind (~45 GW) as well as more battery storage, pumped storage, demand response, and energy efficiency are selected as early as 2035 such that in this scenario, the new resource additions are almost five time the new builds in S1. These capacity additions increase even more substantially by 2045.

Figure 14. Large levels of new resource additions to meet the growing load, PRM needs and emissions reductions (assumes LSR Dams are NOT breached)



As shown in Figure 15 below, all four scenarios result in a sharp near-term decline in carbon emissions, driven by Washington and Oregon policies that drive coal retirement this decade. By 2045, Scenario 1, which requires 100% clean retail sales, shows an ~85% decline in carbon emissions relative to 1990 levels. Scenario 2 eliminates all carbon emissions by 2045.

Figure 15. Northwest Carbon Emissions

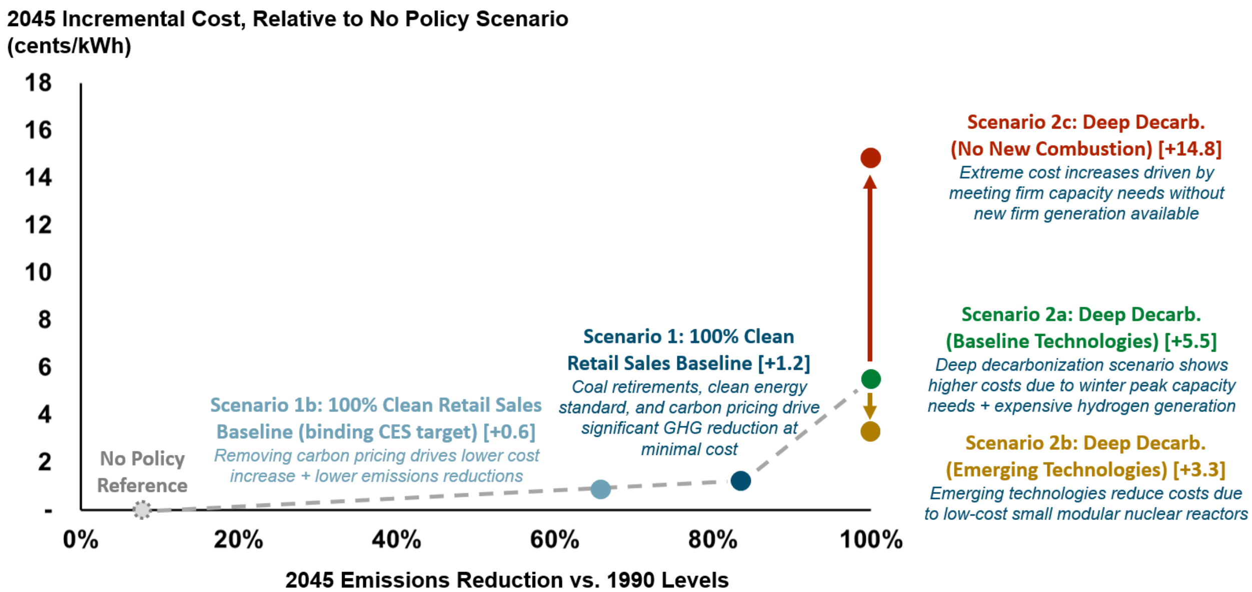


To put cost impacts in context, a "No Policy Reference" case uses the baseline load forecast and removes all electric clean energy policies, retaining the region's coal power with little emissions decline. The four clean energy futures modeled are compared against this Reference Case on A) their cost impacts, measured in incremental cents/kWh relative to the Reference, and B) their carbon emissions reductions, relative to 1990 levels. By 2045, as shown in Figure 16, with the region's aggressive carbon policies in place, emissions can be reduced by over 80% with a relatively small cost impact (+1.2 cents/kWh relative to the region's current average retail rate of 8-9 cents/kWh). Without a carbon price (scenario 1b), emissions are reduced ~65% with a cost impact of 0.6 cents/kWh. Reaching a zero-carbon grid with increasing electric loads requires significantly more investment, increasing carbon reductions to 100% of 1990 levels, but also increasing costs by 3.3-14.8 cents/kWh. This range is highly dependent upon the availability of emerging technologies and their assumed costs. The low end assumes that low-cost small modular nuclear reactors become commercialized by 2035. The high end assumes no new combustion resources (such as green hydrogen)[27] or other emerging technologies are available[28], showing that relying only on non-firm resource additions (renewable energy, demand side resources, and short- to medium-duration storage) leads to much higher costs.

[27] The authors recognize that hydrogen can be used to generate electricity by fuel cells instead of combustion turbines. That scenario would look similar to Scenario 2a, where the combustion plant additions are replaced with many GW of fuel cells for firm capacity needs.

[28] Floating offshore wind was allowed in the no new combustion case since it was required to allow a feasible solution without making any other firm capacity additions available in the model.

Figure 16. Cost Impacts Compared to Emissions Reduction Impacts



NOTES:
- 2020 average retail rates for OR and WA were 8-9 cents/kWh; 1990 electric emissions were ~33 MMT
- High electrification scenarios would avoid natural gas infrastructure costs, which would offset some of the electric peaking infrastructure cost increase

LSR Dams Replacement

The resource replacement portfolios and costs of replacing the LSR dams are reported in this section.

Capacity and energy replacement

In the midterm, given the expectations of load growth and coal capacity retirements resource adequacy needs are a primary driver of LSR dam replacement needs, with around 2 GW of additional firm dual fuel natural gas and hydrogen combustion plants selected to replace the LSR dams' capacity in Scenarios 1, 1b, 2a, and 2b (see Table 10). (Note that, these turbines may initially burn natural gas when needed during reliability challenged periods but would transition to hydrogen by 2045 to reach zero-emissions.) If advanced nuclear is available as assumed in Scenario 2b, it replaces renewables and some of the combustion resource builds. In addition to firm resources, some of the LSR capacity is replaced by renewables in Scenarios 1 and 2a, mostly by wind, solar, and a small amount of battery storage. In Scenario 2c, with no combustion or advanced nuclear available, a very large buildout of renewable capacity (in the order of 12 GW) is required to replace the capacity of LSR dams, due to resource availability and the fast decline in solar and wind ELCCs as early as 2035. Small amount of geothermal capacity is also part of the portfolio in 2035.

In the long term, the dam's carbon-free energy is replaced by a combination of wind power and another "clean firm" resource when available. Scenario 2a shows additional hydrogen generation, as well as small levels of energy efficiency and battery storage. In Scenario 2b, the LSR dams are entirely replaced by clean firm capacity of hydrogen combustion plants and nuclear SMRs, whereas in Scenario 2c, a large capacity of wind and solar is relied upon to replace both the carbon-free energy and firm capacity of the LSR dams.

Overall, the magnitude of replacement portfolio capacities is close in both snapshot years (2035 and 2045) meaning that immediate capacity additions are necessary to replace LSR dams given the retirement year of 2032 while the capacity needs sustain throughout the modeling period. The early removal of LSR dams (i.e., by 2024) moves up the timing of the replacement portfolio to 2025 instead of 2035 in S1 with 2024 removal, but the replacement portfolio remains similar.

Table 10. Optimal portfolios to replace the LSR dams

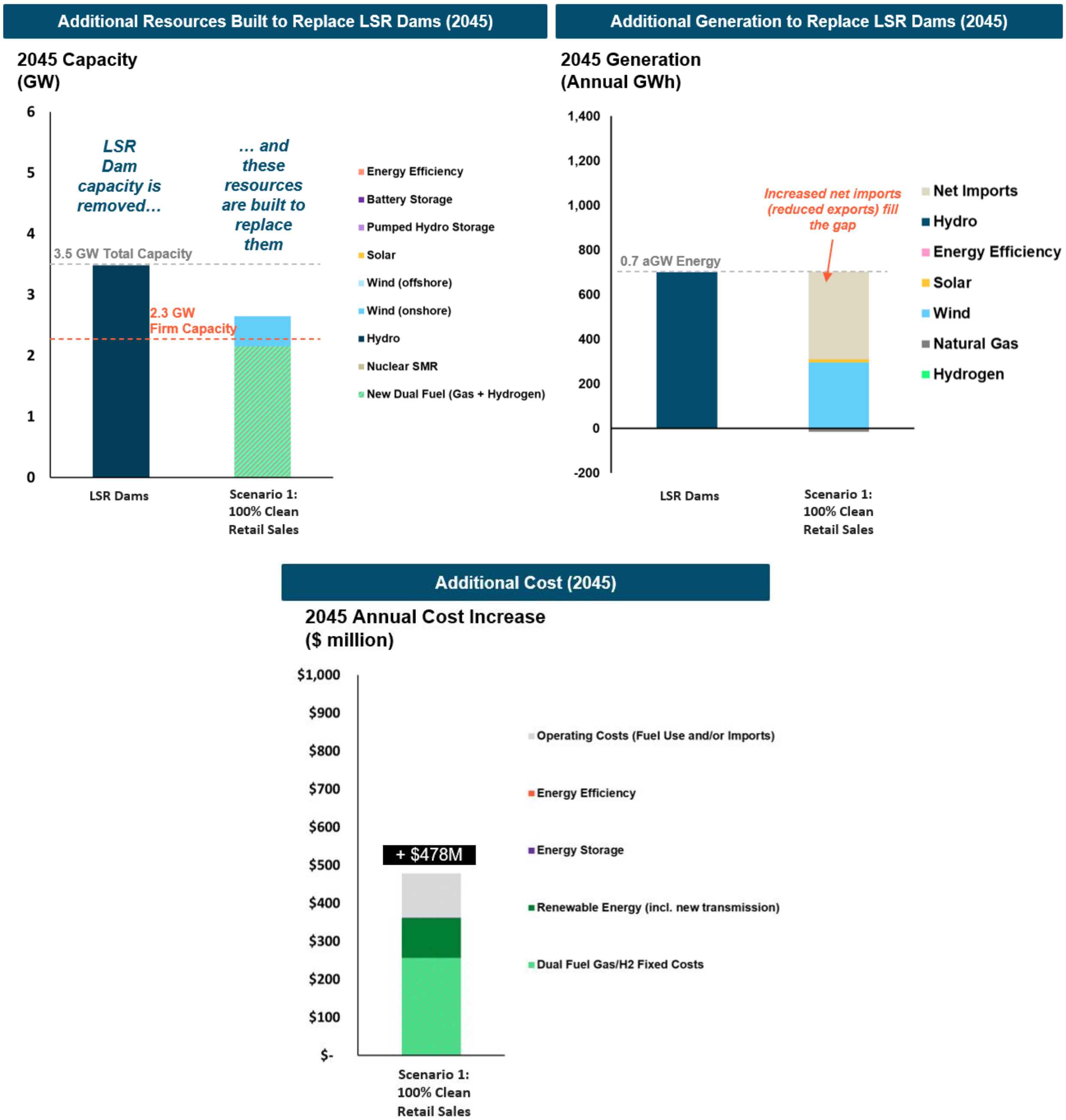
Scenario	Replacement Resources Selected, Cumulative by 2035[29] (GW)	Replacement Resources Selected, Cumulative by 2045 (GW)
Scenario 1: 100% Clean Retail Sales	+ 1.8 GW dual fuel NG/H2 CCGT - 0.5 GW solar + 1.3 GW wind + 0.1 GW li-ion battery	+ 2.1 GW dual fuel NG/H2 CCGT + 0.5 GW wind
Scenario 1: 100% Clean Retail Sales (2024 dam removal)	+ 1.8 GW dual fuel NG/H2 CCGT - 0.5 GW solar + 1.4 GW wind + 0.1 GW li-ion battery	+ 2.1 GW dual fuel NG/H2 CCGT + 0.5 GW wind
Scenario 1b: 100% Clean Retail Sales (binding CES target)	+ 2.2 GW dual fuel NG/H2 CCGT + 0.1 GW li-ion battery	+ 1.8 GW dual fuel NG/H2 CCGT + 1.3 GW solar + 1.2 GW wind
Scenario 2a: Deep Decarbonization (Baseline Technologies)	+ 2.0 GW dual fuel NG/H2 CCGT + 0.6 GW wind + 0.1 GW li-ion battery	+ 2.0 GW dual fuel NG/H2 CCGT + 0.3 GW li-ion battery + 0.4 GW wind + 0.05 GW advanced EE + 1.2 TWh H2-fueled generation
Scenario 2b: Deep Decarbonization (Emerging Technologies)	+ 1.7 GW dual fuel NG/H2 CCGT + 0.6 GW nuclear SMR	+ 1.5 GW dual fuel NG/H2 CCGT + 0.7 GW nuclear SMR
Scenario 2c: Deep Decarbonization (No New Combustion)	+ 9.1 GW offshore wind + 0.1 GW wind + 1.0 GW solar + 0.3 GW geothermal + 1.5 GW li-ion battery	+ 10.6 GW wind + 1.4 GW solar

Figure 17 through Figure 21 show details of the capacity replacement, energy replacement, and cost breakdown for Scenarios 1, 1b, 2a, 2b, and 2c. LSR dams energy in these scenarios is replaced with wind, solar, net imports (i.e. reduced exports of hydropower outside the Core NW), and – in Scenario 2a – additional hydrogen generation, which is necessary in 2045 to meet the zero-carbon goal without the flexible LSR dam winter generation. The cost charts show that the dual fuel gas plants make up

[29] Replacement resources are calculated by comparing the "with LSR dams" RESOLVE portfolio to the "without LSR dams" RESOLVE portfolio. This means some resources may be built in 2035, such as 0.3 GW of geothermal in scenario 2c, that are not built when the dams are included. However, those resources may have already been selected in the "with LSR dams" case by 2045, hence do not show up as additional resource replacement needs in 2045. This explains the different resource changes between 2035 and 2045.

approximately half of the 2045 annual costs in Scenario 1 and approximately a quarter of the 2045 annual costs in Scenario 2a, which includes additional costs for energy efficiency and hydrogen generation.

Figure 17. Scenario 1: Capacity Replacement, Energy Replacement, and Costs[30]



[30] Regarding the "net imports" component of the energy replacement, this refers to either increased imports, decreased exports (generally of carbon-free energy), or a combination of both, such that RESOLVE does not need to build enough new generation to fully replace the LSR dams output. For instance, the region could export less hydropower to California and other neighbors to replace the LSR dams output without necessarily increasing Northwest carbon emissions in Scenario 1.

Figure 18. Scenario 1b Capacity Replacement, Energy Replacement, and Costs

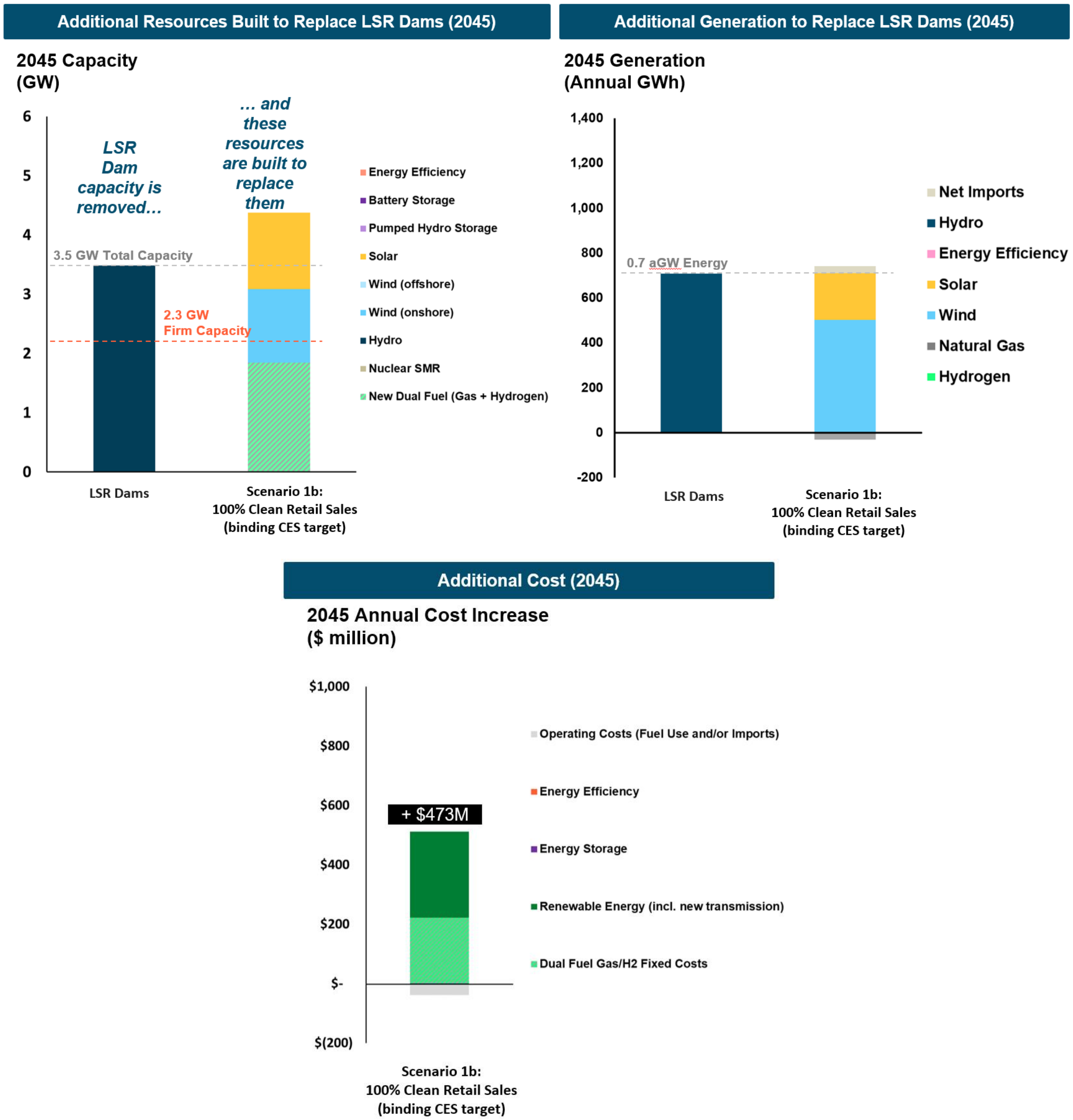


Figure 19. Scenario 2a Capacity Replacement, Energy Replacement, and Costs

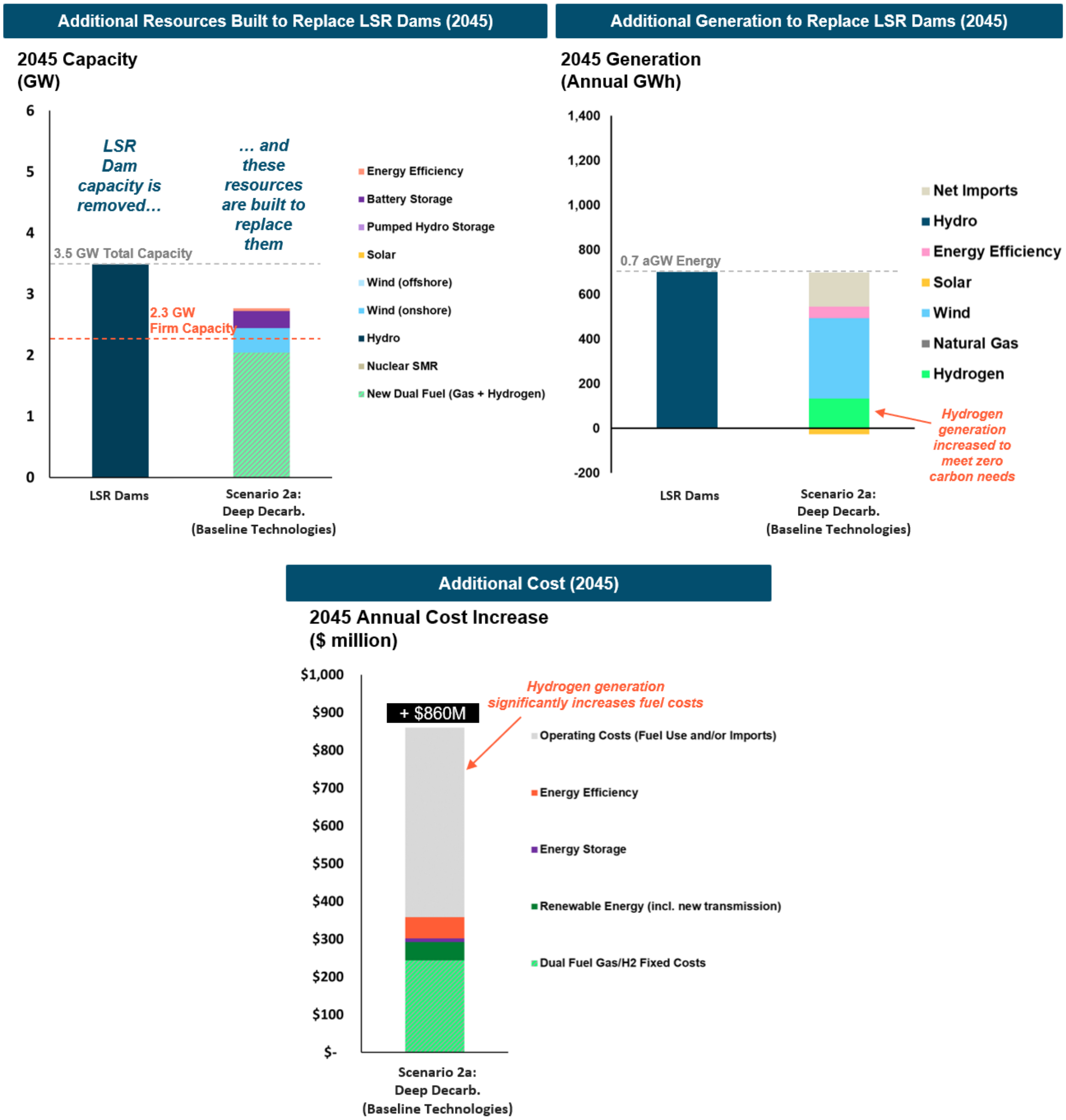
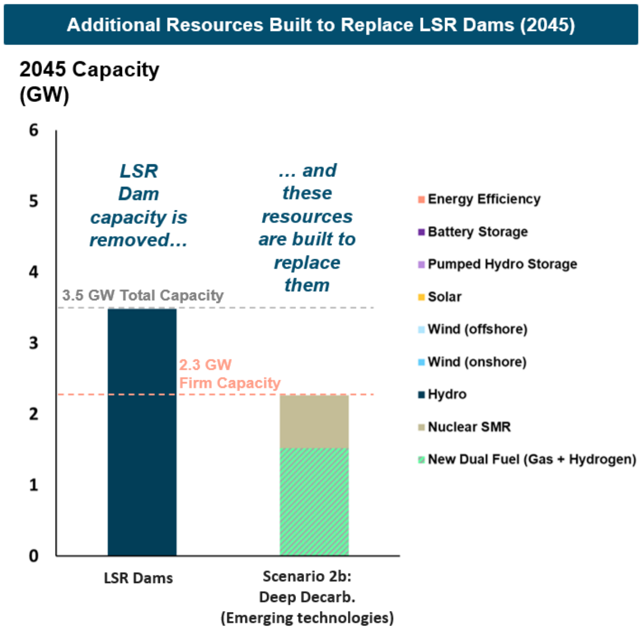
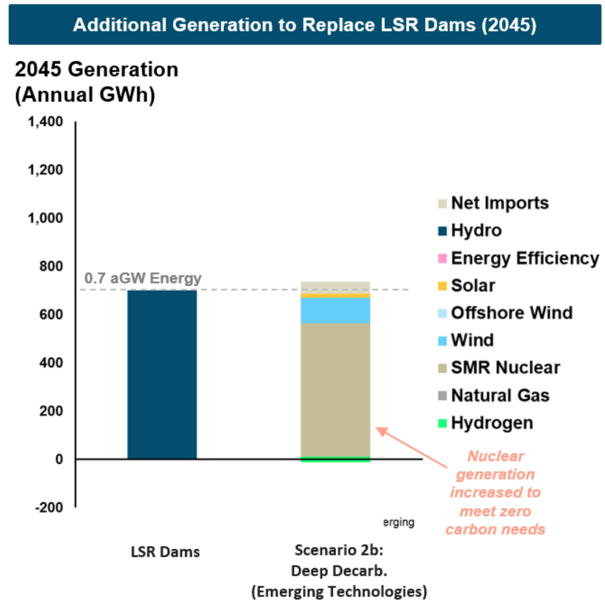


Figure 20. Scenario 2b Capacity Replacement, Energy Replacement, and Costs





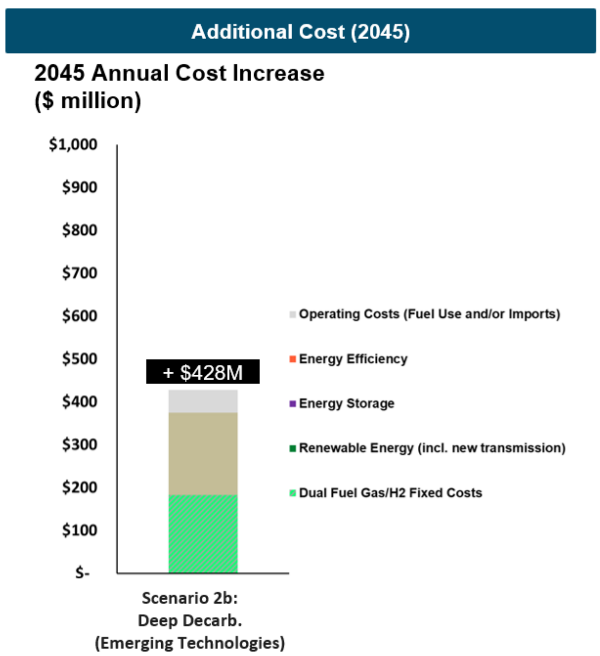
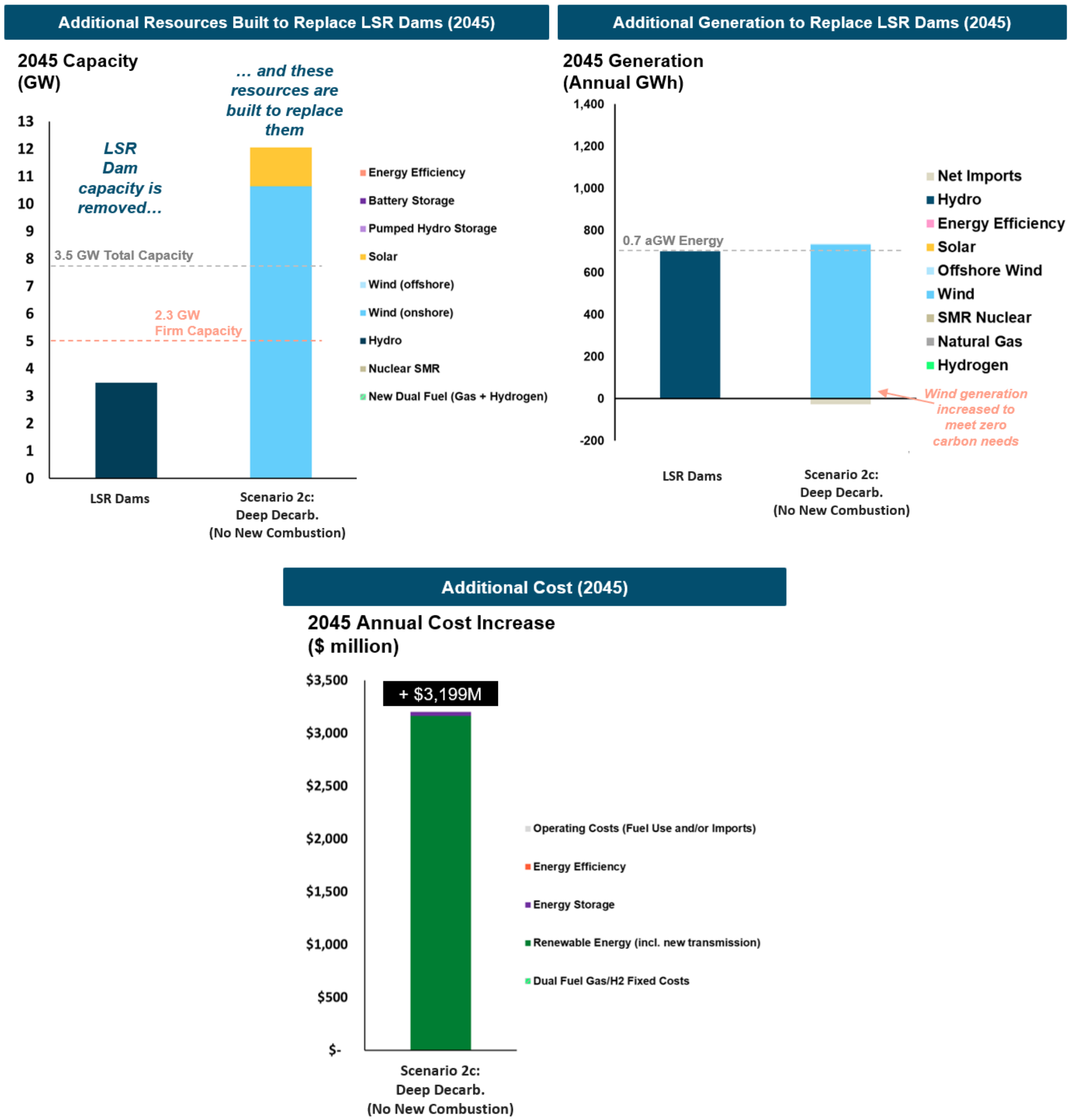


Figure 21. Scenario 2c Capacity Replacement, Energy Replacement, and Costs[31]



Replacement costs

The LSR dams provide a relatively low-cost source of GHG-free energy and firm capacity. Incremental costs for replacement resources are summarized in this section. All costs are shown in real 2022 dollars.

[31] NOTE: the energy replacement does not show the total potential energy output of the wind built to replace the dams, because much of the potential energy output is curtailed due to oversupply of wind built for resource adequacy needs.

Incremental costs to replace the power services of the LSR dams ranges from $69-139/MWh across most scenarios. Scenario 2c, however, shows a much higher replacement power cost of $277-517/MWh. These incremental costs are much higher than costs of maintaining the LSR dams (i.e., $13-17 per MWh[32]); they are calculated by taking the incremental fixed and variable investment costs for the no LSR RESOLVE runs and dividing them by the LSR annual generation being replaced. See the details in Table 11.

Table 11. Incremental costs to replace LSR generation in 2045

Scenario	Incremental net costs in 2045[33], including avoided LSR dam costs (Real 2022 $/MWh)	Incremental gross costs in 2045[34], excluding $17/MWh avoided LSR dam costs (Real 2022 $/MWh)
Scenario 1: 100% Clean Retail Sales	$77/MWh	$94/MWh
Scenario 1: 100% Clean Retail Sales (2024 dam breaching)	$82/MWh	$99/MWh
Scenario 1b: 100% Clean Retail Sales (binding CES target)	$77/MWh	$94/MWh
Scenario 2a: Deep Decarb. (Baseline Technologies)	$139/MWh	$156/MWh
Scenario 2b: Deep Decarb. (Emerging Technologies)	$69/MWh	$86/MWh
Scenario 2c: Deep Decarb. (No New Combustion)	$277-517/MWh	$294-534/MWh

The LSR dams' total replacement costs (in net present value) and annual replacement costs for 2025, 2035, and 2045 are shown in Table 12. NPV replacement costs are calculated based on discounting at a 3% discount rate, representative of the approximate public power cost of capital, over a 50-year time horizon following the date of breaching. Scenario 1 (100% clean retail sales) replacement costs are approximately $12-12.4 billion in net present value (NPV) in the year of breaching (in 2032); costs increase to $12.8 billion NPV if breached in 2024. Total replacement costs are similar in the economy-wide deep decarbonization scenario when emerging technology is available (scenario 2b), showing $11.2 billion NPV. Replacement costs are significantly higher in scenario 2c where no new combustion resources are allowed ($42-77 billion NPV). The economy-wide deep decarbonization (baseline technology scenario), 2a, shows more costly replacement ($19.6 billion NPV) than when nuclear SMRs are available, but lower costs than scenario 2c, due to the availability of hydrogen-enabled gas plants.

---

32 BPA directly funds the annual operations and maintenance of the Lower Snake River Compensation Plan (LSRCP) facilities. The cost of generation at the lower Snake River dams is in the range of $13/MWh without LSRCP and $17/MWh with LSRCP. Congress authorized the LSRCP as part of the Water Resources Development Act of 1976 (90 Stat.2917) to offset fish and wildlife losses caused by construction and operation of the four lower Snake River projects.

33 The generation replacement costs are calculated using the incremental RESOLVE's Core Northwest revenue requirement increase with LSR dams breached divided by the annual MWh of the LSR dams assuming 706 average MW generation.

34 The generation replacement costs are calculated using the incremental RESOLVE's Core Northwest revenue requirement increase with LSR dams breached divided by the annual MWh of the LSR dams assuming 706 average MW generation.

Annual costs increase by $415-860 million after LSR dams' removal in scenarios 1, 2a, and S2b. In Scenario 2c, the cost increase is in the order of $1.9-3.2 billion per year. Replacement costs generally increase over time due to increasingly stringent clean energy standards and electrification-driven load growth. The 2045 cost increases translate to 8-18% growth in BPA's public power customers costs in scenarios 1, 1b, 2a and 2b (assuming current retail rates are about 8.5 ₵/kWh based on OR and WA average retail rates). In these scenarios, public power households would see an increase in annual electricity costs of $100-230/yr in 2045. In Scenario 2c, rate impacts could be as high as 34-65%, which is equivalent to annual residential electricity bills raising by up to $450-850 per year.[35] Note that these incremental cost increases include the ongoing LSR dams costs, such as operations and maintenance costs, avoided by breaching the dams, but do not include the costs of breaching. The rate impacts shown are only for the LSR dams' replacement, they do not include the additional rate increases driven by higher loads or clean energy needs (that are covered in the section *Electricity Generation Portfolios with the Lower Snake River Dams Intact* above), which apply even without removing generation from the LSR dams.

Table 12. Total LSR Dams replacement costs

	NPV Total Costs (Real 2022 $)[36]	Annual Costs Increase (Real 2022 $)			Incremental Public Power Costs[37]
	In the year of breaching (2032 or 2024)	2025	2035	2045	2045
Scenario 1: 100% Clean Retail Sales	$12.4 billion	n/a	$434 million	$478 million	0.8 ₵/kWh [+9%]
Scenario 1: 100% Clean Retail Sales (2024 dam breaching)	$12.8 billion	$495 million	$466 million	$509 million	0.8 ₵/kWh [+9%]
Scenario 1b: 100% Clean Retail Sales (binding CES target)	$12.0 billion	n/a	$445 million/yr	$473 million/yr	0.8 ₵/kWh [+9%]
Scenario 2a: Deep Decarb. (Baseline Technologies)	$19.6 billion	n/a	$496 million	$860 million	1.5 ₵/kWh [+18%]
Scenario 2b: Deep Decarb. (Emerging Technologies)	$11.2 billion	n/a	$415 million	$428 million	0.7 ₵/kWh [+8%]
Scenario 2c: Deep Decarb. (No New Combustion)	$42 – 77 billion[38]	-	$ 1,045 – 1,953 million/yr	$1,711 – 3,199 million/yr	2.9 – 5.5 ₵/kWh [+ 34 – 65%]

[35] Annual residential customer cost impact assumes 1,000 kWh per month for average residential customers in Oregon and Washington in scenario 1 and 1,280 kWh per month for scenario 2, per the 28% retail sales increase due to electrification load growth.

[36] NPV replacement costs are based on discounting at a 3% discount rate, representative of the approximate public power cost of capital, over a 50-year time horizon following the date of breaching.

[37] Incremental public power costs are calculated assuming that all the replacement costs are paid by BPA Tier I customer, using the assumed 2022 Tier I annual sales of 58,686 GWh.

[38] A range of costs was developed for this scenario based on the assumed transmission needs for renewable additions. High end assumes 100% of nameplate, low end assumes 25% of nameplate (approx. marginal ELCC of renewable additions). Low end represents a higher ratio of renewable capacity to transmission capacity, recognizing that much of the additional energy added by 2045 would be curtailed due to over-supply.

Carbon emissions impacts

LSR dams provide emissions-free generation for Northwest and depending on what these dams are replaced with, may impact the emissions associate with the electricity systems. The removal of LSR dams may potentially cause an increase in emissions over the near- or mid-term horizon. In Scenario 1, the 2024 LSR dam breaching scenario results in substantial increases to carbon emissions through 2030, in the range of 1-2.8 MMT/yr or 15-25% of the annual Northwest emissions. This scenario does not have a binding GHG constraint, and the region meets its clean energy goals in the near term without the dams. RESOLVE therefore does not replace all the LSR dam energy with clean resources.

Under 2032 breaching scenarios, carbon emissions increases are observed in the mid-term (0.7-1.5 MMT/yr. or ~10% of the region's carbon emissions in 2035). Scenario 1b, when the CES target binds in 2045, shows to GHG increases in 2045, since the GHG-free energy of the LSR dams is replaced by solar and wind power. The economy-wide deep decarbonization cases all reach zero carbon emissions by 2045, so breaching the dams does not increase emissions in that year; RESOLVE instead builds the resources needed to replace all of the GHG-free energy to meet the zero-carbon constraint.

Additional considerations

Depending on how the future of the electric grid evolves, there might be significant land-use associated with renewables expansion, more so if LSR dams are removed in conditions similar to Scenario 2c where significant capacity additions from solar and wind resources would be necessary.

Key Uncertainties for the Value of the Lower Snake River Dams

This study explicitly captures the following key drivers of the LSR dams power service replacement needs:

+ Replacing the **GHG-free energy**, **firm capacity**, **operating reserves**, and **operational flexibility** of the dams

Uncertainty of the LSR dam value is considered under scenarios of:

+ **Clean energy policy**: replacement of carbon-free power becomes increasingly critical to reach a zero-emissions electricity grid
+ **Load growth**: replacement energy and capacity needs may change with increased electrification and peak higher winter space heating needs
+ **Technology availability**: replacement is more expensive with fewer emerging technology resource options
+ **Timing**: replacement was focused on breaching in 2032, but a 2024 sensitivity was also considered
+ **Carbon pricing**: a sensitivity scenario was considered for scenario 1 that considered no carbon pricing, which causes the 100% CES target to bind

Additional uncertainties regarding the value of the dams are:

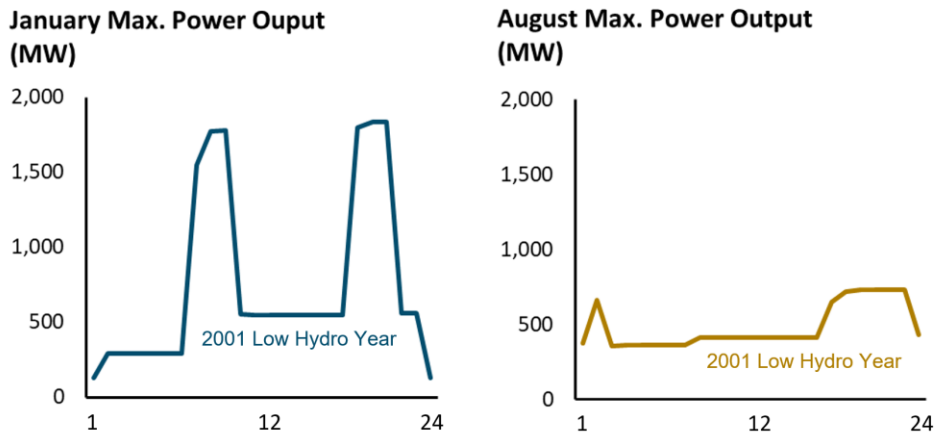
- **LSR dams annual energy output**: E3's existing RESOLVE model data uses historical hydro years 2001, 2005, and 2011 as representative of the regional long-term average low/mid/high hydro year conditions. The data for the Columbia River System dams was adjusted to reflect the Preferred Alternative operations defined in the CRSO EIS. However, for the LSR dams, these selected historical hydro years resulted in a relatively low output of ~700 average MW, whereas the dams may generate ~900 average MW on average across the full historical range of hydro conditions. Therefore, E3's analysis likely underestimates the energy value of the dams and costs for replacing that extra GHG-free energy.
- **LSR dams firm capacity counting**: as resource adequacy is found to be a key driver of future resource needs, the firm capacity contributions of the LSR dams is a key driver of their value. See below for further discussion of this uncertainty.
- **Replacement resource capacity contributions**: if Northwest reliability challenges dramatically shift into the summer, this would also impact the capacity value of replacement resources. Directionally, this would likely increase the capacity value of energy storage, and change the relative value of solar and wind. It is expected that additional battery storage would be part of the regional capacity additions in lieu of dual fuel natural gas + hydrogen plants. See below for further discussion of this uncertainty.
- **Replacement of transmission grid services:** this study does not focus on the transmission grid reliability services provided by the LSR dams. These services likely can be replaced by a combination of the new resources selected by RESOLVE and additional local transmission system investments. A qualitative summary of the transmission grid reliability services of the dams is summarized in the appendix of this report.

LSR Dams Firm Capacity Counting

Since resource adequacy is found to be a key driver of future resource needs, the firm capacity contribution of the LSR dams is a key driver of their value. E3 uses a regional hydro capacity value estimate for the LSR dams in this study, based on the PNUCC regional hydro capacity value assumption. More detailed follow-on ELCC studies could be done to confirm the LSR dams' capacity value, though proper and coordinated dispatch of the Northwest hydro fleet would be necessary to develop an accurate and fair value of the LSR dams within the context of the overall hydro fleet.

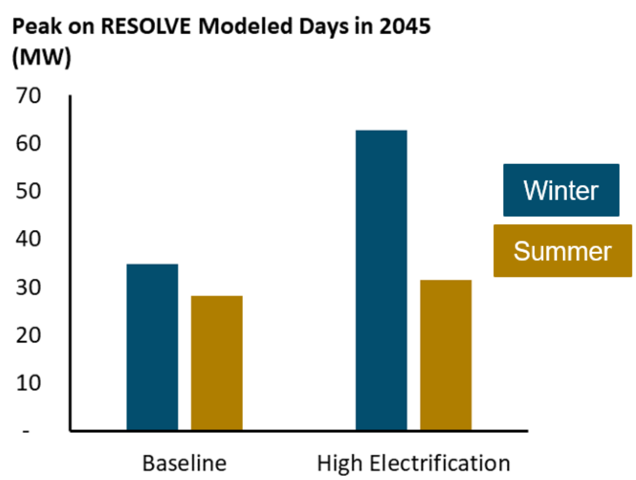
This study validated the assumed 2.28 GW of firm capacity from the LSR dams by considering BPA modeled LSR dams dispatch under 2001 dry hydro year conditions using the CRSO EIS spill constraint adjusted hourly modeling provided by BPA. Maximum January output (plus 100-250 MW of operating reserves) was 1.9-2.1 GW (~56-60% of total capacity), slightly less but close to the 65% regional hydro value the study assumes.

Figure 22. BPA-Modeled LSR Dam Output During the 2001 Low Hydro Year with CRSO EIS Preferred Alternative operations



The other capacity value uncertainty is whether the Northwest will remain winter reliability challenged or whether reliability events will shift to the summer due to climate impacts on load patterns and hydro output. If reliability challenges did shift to the summer, the LSR dam firm capacity contribution would be significantly lower than assumed. However, E3 believes it is reasonable to assume under high electrification scenarios that the region will remain winter challenged due to peak space heating needs, as shown in figure below.

Figure 23. Winter vs. Summer Peak Loads

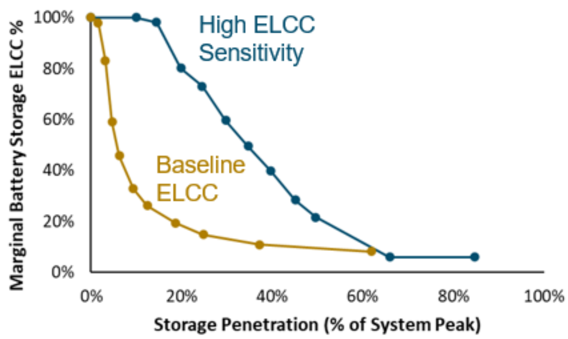


To address the capacity value uncertainty, a post-processing analysis was performed based on the replacement resources selected for firm capacity replacement. Based on this analysis performed on scenarios 1 and 2a, relative to the 2.28 GW assumption used in this study, it is estimated that a 1.5 GW firm capacity value (43%) for the dams would lower the NPV replacement costs by 9-20% and a 1.0 GW firm capacity value (29%) would lower the NPV replacement costs by 14-33%.

Replacement Resources Firm Capacity Counting

If Northwest reliability challenges dramatically shift into the summer, this would also impact the capacity value of replacement resources. One key input assumption this would change is the capacity value of battery storage additions, which were previously limited due to the Northwest wintertime energy-constrained reliability events causing charging sufficiency challenges for energy storage resources. To test whether higher energy storage ELCCs would impact the LSR dams replacement resources and replacement costs, a high storage ELCC sensitivity scenario was analyzed, per the ELCC inputs shown in Figure 24 below. This analysis was performed on scenarios 1 and 2a.

Figure 24. Inputs for High Battery Storage ELCC Sensitivity



In Scenario 1, with the LSR dams intact, higher battery ELCCs cause another 1.5 GW of batteries to be selected and 1.4 GW less dual fuel natural gas and hydrogen plants. In Scenario 2a, with the LSR dams intact, higher battery ELCCs cause another 2.4 GW of batteries and another 0.3 GW of wind to be selected, with 3.6 GW less dual fuel natural gas and hydrogen plants.

When the LSR dams are assumed to be breached, the differences in replacement resources are relatively small. In Scenario 1, an additional ~0.2 GW of battery storage, an additional 0.2 GW of wind, and 0.2 GW less dual fuel natural gas and hydrogen plants are selected to replace the dams. In Scenario 2a, an 0.3 GW less battery storage, 0.3 GW less wind, and an additional 0.1 GW of dual fuel natural gas and hydrogen plants are selected to replace the dams. This is because scenario 2a builds more wind and batteries in the base case already with the dams not breached, so the model prefers to select fewer of those resources for LSR dams replacement. Annual replacement costs in 2045 are 2% lower in scenario 1 and the same in scenario 2a. These results indicate that higher storage ELCCs would allow the region to build less dual fuel natural gas and hydrogen plants, but because energy storage ELCCs eventually saturate in either case, the replacement resources for the dam are not significantly changed and there is little impact on the replacement costs.

Conclusions and Key Findings

This study uses E3's Northwest RESOLVE model to study optimal capacity expansion scenarios with and without the lower Snake River dams, to determine the replacement resources and cost impacts to replace the dams' power output. RESOLVE is an optimal capacity expansion and dispatch model that determines a least-cost set of investment and operational strategies to enable the "Core Northwest" region – consisting of Washington, Oregon, Northern Idaho, and Western Montana – to achieve its long-term clean energy policy goals at least-cost, while ensuring resource adequacy and operational reliability. RESOLVE has been used in several prior studies of electricity sector decarbonization in the Pacific Northwest[39]. Using RESOLVE allows for a dynamic optimization that considers replacement resource needs in the context of long-term system load and policy drivers, not just the near-term resource mix and needs of the system today. The dams are assumed to be breached in 2032, except for one sensitivity that considered 2024 breaching.

This study's scenario design focuses on three key variables – clean energy policy, load growth, and emerging technology availability – that impact the cost to replace the dams.

Even with the dams in place, the region's clean energy goals and potential electrification load growth drive a significant need for new resources. In all scenarios, significant energy efficiency and customer solar is embedded into the load forecast, based on the NWPCC's 8th Power Plan. Additionally, 6 gigawatts ("GW" or 6,000 MW) of coal capacity is retired by 2030, while increasing carbon prices incent further clean energy resource additions. In Scenario 1, the regional power system is required to meet a goal of generating enough clean energy to provide 100% of retail electricity sales, on an average basis over a calendar year. This requires an additional 5.5-7 GW of solar and 4.6-6 GW of wind by 2045 to achieve the clean energy goal; 0.6 GW of battery storage, 2 GW of demand response, and 9 GW of dual fuel natural gas + hydrogen combustion plants are also added to meet the region's resource adequacy needs.[40]

Though all scenarios require more "firm" resources – resources that can generate when needed and operate for as long as needed – to meet peak loads, these resources are in higher demand in Scenario 2, in which all greenhouse gas emissions are eliminated from the regional power system by 2045. This scenario also assumes that electrification results in much higher electric loads, particularly in wintertime due to electrification of natural gas space heating in buildings. The baseline scenario (2a) selects additional wind, solar, and geothermal to meet clean energy needs as well as demand response, some battery storage, and 27 GW natural gas and hydrogen dual fuel combustion plants to meet reliability needs. An alternative "emerging technology" scenario selects 17 GW of advanced nuclear technology (small modular reactors or "SMRs") by 2045, in place of the firm capacity provided by natural gas generators

[39] Pacific Northwest Low Carbon Scenario Analysis, December 2017, https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/; Pacific Northwest Zero-Emitting Resources Study, January 2020, https://www.ethree.com/e3-examines-role-of-nuclear-power-in-a-deeply-decarbonized-pacific-northwest/

[40] E3 ran two versions of scenario 1. In scenario 1, the high carbon price assumed drives the region higher than the 100% CES target, making it a non-binding constraint in the model. In scenario 1b, the 100% CES target is binding in 2045, causing the need to fully replace the GHG-free energy output of the LSR dams. The values shown here represent the range of additions across both scenarios.

while reducing the required quantities of wind, solar and batteries that are needed. The “no new combustion” scenario does not allow emerging clean firm technologies such as hydrogen combustion turbines, gas generation with carbon capture and sequestration (CCS) or SMRs. As a result, it requires impractically high levels of additional onshore wind, offshore wind, and battery storage to meet firm capacity and carbon reduction needs, quadrupling the total installed MW of the Northwest grid by 2045.

When the power services provided by the dams are removed from the regional power system, RESOLVE selects an optimal, i.e., least-cost portfolio of replacement resources that meets the Northwest’s clean energy and system reliability needs. These replacement resources require a large investment and come at a substantial cost that increase over time as the region’s clean energy goals become more stringent. In the latter years, the replacement costs are highly dependent on scenario-specific assumptions about the availability of emerging technologies. RESOLVE primarily replaces the carbon-free energy from the dams with additional wind and solar power and the firm capacity with dual fuel natural gas and hydrogen combustion plants. Small amounts of additional energy efficiency and battery storage are also selected in some scenarios. By 2045, the dual fuel plants added burn additional hydrogen on low wind days to replace the carbon-free energy provided by the dams. Scenario 2b selects additional nuclear SMRs in lieu of some of the wind and gas resources. Scenario 2c disallows the new combustion plants, even those that would burn green hydrogen, and other emerging technologies, requiring a very large buildout of wind and solar power to replace both the firm capacity and the carbon-free energy of the dams.

The long-term emissions impact of removing the generation of the lower Snake River dams will depend on the implementation of the Oregon and Washington electric clean energy policies. Both a 100% clean retail sales and a zero-carbon emissions target require replacement of most or all of the LSR dams’ GHG-free energy. However, without additional earlier carbon-free resource investments beyond those modeled in this study to meet clean energy policy trajectories, carbon emissions may increase initially when the dams are breached, before declining by 2045 as the carbon policy becomes more stringent.

KEY FINDINGS:

+ ***Replacing the four lower Snake River dams while meeting clean energy goals and system reliability is possible but comes at a substantial cost***, even assuming emerging technologies are available:
    - Requires 2,300 – 4,300 MW of replacement resources
    - An annual cost of $415 million – $860 million by 2045
    - Total net present value cost of $11.2-19.6 billion based on 3% discounting over a 50-year time horizon following the date of breaching
    - Increase in costs for public power customers of $100 – 230 per household per year (an 8 – 18% increase) by 2045
+ The biggest cost drivers for replacement resources are the need to replace the lost ***firm capacity for regional resource adequacy*** and the need to replace the lost ***zero-carbon energy***
+ Replacement becomes ***more costly over time*** due to increasingly stringent clean energy standards and electrification-driven load growth
+ ***Emerging technologies*** such as hydrogen, advanced nuclear, and carbon capture ***can limit the cost of replacement resources*** to meet a zero emissions electric system, but the pace of their commercialization is highly uncertain

- In economy-wide deep decarbonization scenarios, ***replacement without any emerging technologies requires very large renewable resource additions at a very high cost*** (12 GW of wind and solar at $42-77 billion NPV cost)

Appendix

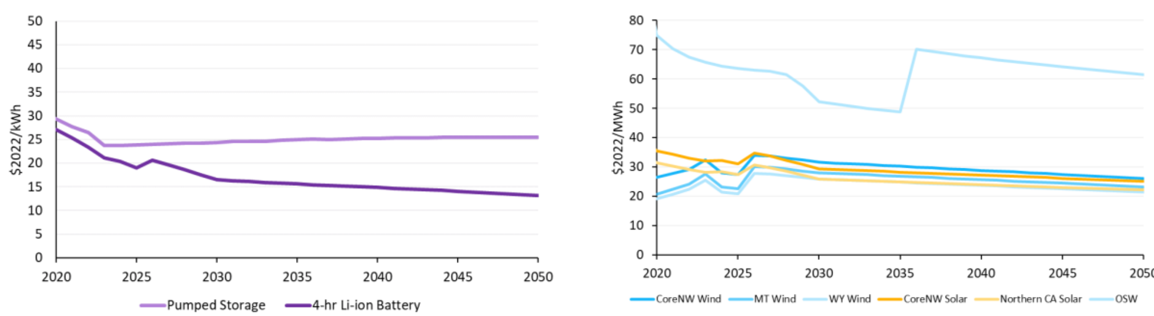
Additional Inputs Assumptions and Data Sources

Candidate resource costs

The technology fixed costs trajectories for candidate resource options are shown in Figure 25 and use the following data sources:

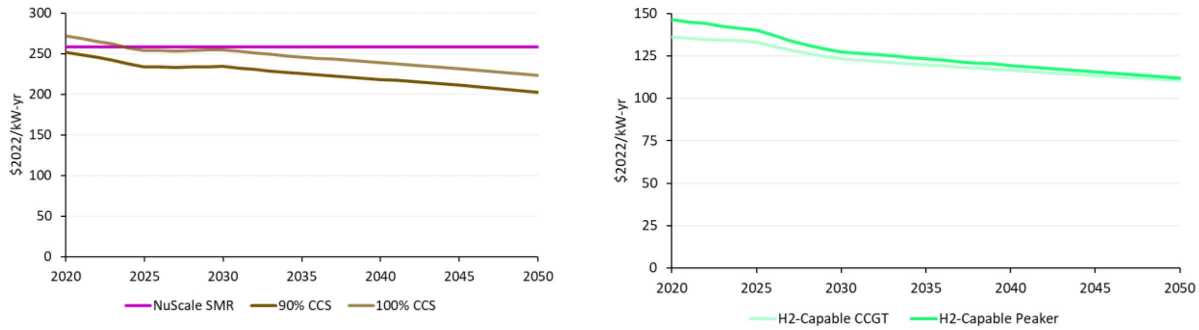
- **Battery Storage:** Costs derived from Lazard LCOS 7.0 and E3 modeling
- **Pumped Storage:** Costs derived from Lazard's last published PHS costs (LCOS 4.0)
- **Renewables (solar, onshore, and offshore wind):** Costs derived from E3's inhouse Pro Forma which integrates the NREL 2021 Annual Technology Baseline
- **Geothermal:** Costs derived from E3's inhouse Pro Forma which integrates the NREL 2021 Annual Technology Baseline
- **Energy Efficiency and Demand Response:** Costs supply curve adjusted for cost effective energy efficiency and DR potential from the 2021 Northwest Power Plan
- **Carbon Capture and Storage (CCS):** Costs derived from E3's inhouse "Emerging Tech" Pro Forma using the NREL 2021 Annual Technology Baseline and Feron et al., 2019.[41]
- **Nuclear Small Modular Reactor (SMR):** Costs are derived from the vendor NuScale, for an "nth of a kind" installation of the technology they are developing
- **Gas and Hydrogen-Capable Technologies:** CCGT and peaker costs are derived from E3's inhouse ProForma which integrates NREL 2021 Annual Technology Baseline. New Hydrogen or natural gas to hydrogen upgrades include a ~10% additional cost that converges with standard CCGT and peaker costs by 2050

Figure 25. All-in fixed costs for candidate resource options[42]



[41] Feron, P., Cousins, A., Jiang, K., Zhai, R., Thiruvenkatachari, R., & Burnard, K. (2019). Towards zero emissions from fossil fuel power stations. International Journal of Greenhouse Gas Control, 87, 188–202.

[42] Storage costs are shown in $/kWh of energy storage. Renewable costs are shown in $/MWh. Clean firm resources (nuclear, CCS, hydrogen CCGT or peakers) are shown in $/kW-yr, since their $/MWh costs are a function of their runtime that RESOLVE would determine endogenously.

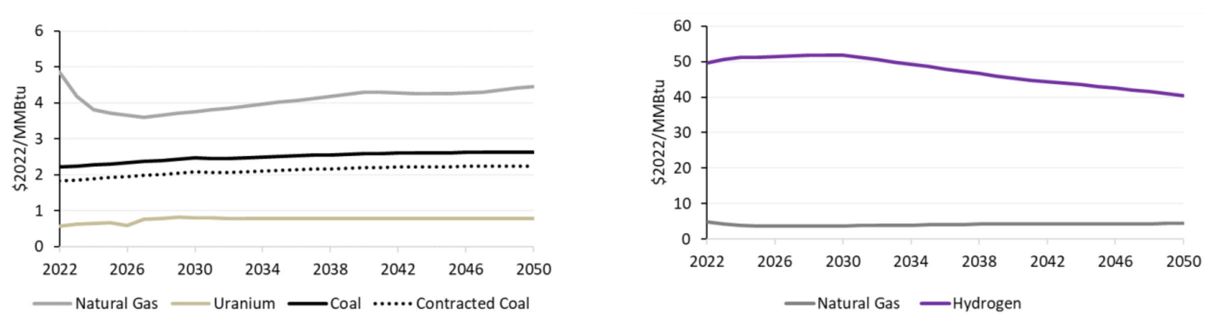


Fuel prices

The fuel price forecasts used in this study are derived from a combination of market data and fundamentals-based modeling of natural gas supply and demand. Wholesale gas prices are pulled from forward contracts from NYMEX (Henry Hub) and Amerex and MI Forwards (all other hubs) for the next five years, after which the Henry Hub forecast trends towards EIA's AEO natural gas price by 2040. All other hubs forecast after the first five years are based on the average 5-year relationship between their near-term forward contracts and that of Henry Hub. Data sources used for fuel price forecasts used in modeling are as follows and the trajectories are presented in Figure 26:

+ **Natural gas prices:** In near term, SNL NG price forecasts (i.e., for 2022-2026); and in long term, the EIA's AEO 2040 forecasts are used. Recent fuel cost increases due to market disruptions are excluded from the price trajectory.
+ **Coal prices:** EIA's AEO forecast are used
+ **Uranium prices:** E3's in-house analysis
+ **Hydrogen prices:** Conservative prices are used assuming no large-scale hydrogen economy, and thus electrolyzer capital costs and efficiencies are assumed to improve over time only slightly. Other assumptions include above ground hydrogen storage tanks and delivery via trucks from about 225 miles distance. Electrolyzers use dedicated off-grid Core NW wind power to produce hydrogen.

Figure 26. Fuel price forecasts for natural gas, coal, uranium, and hydrogen

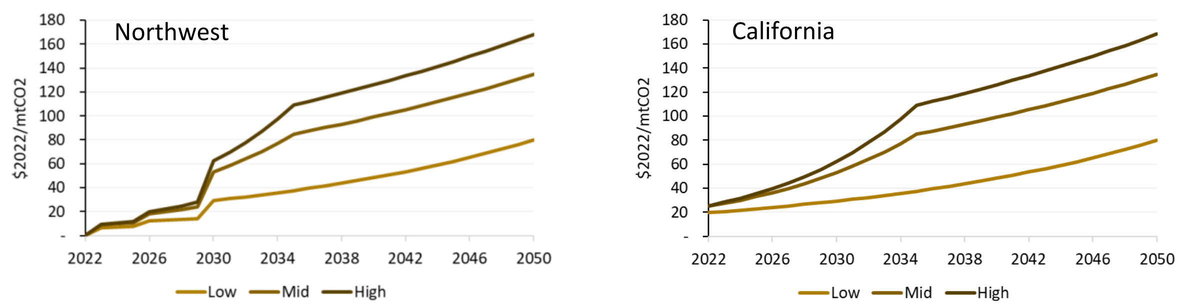


Annual average gas prices are further shaped according to a monthly profile to capture seasonal trends in the demand for natural gas and the consequent impact on pricing.

Carbon prices

For carbon pricing, it is assumed that Washington's cap-and-trade program starts in 2023 at around 50% of California carbon prices. For Oregon, it is assumed that a carbon price policy will be effective by 2026 for the electric sector. Prior to 2026, the Northwest carbon price is a load weighted share of carbon prices in WA and OR. Additionally, it is assumed that both states will converge to California's floor price by 2030. California's carbon prices are adopted from the Final 2021 IEPR GHG Allowance Price Projections (December 2021). Mid carbon prices presented in Figure 27 are used in modeled cases.

Figure 27. Carbon price forecasts for Northwest and California



Scenario 1b assumes no carbon price in the CoreNW zone.

Operating Reserves

It is assumed that all coal, gas, hydro, and storage resources within the Northwest zone can provide operating reserves. Additionally, RESOLVE allows renewable generation to contribute to meeting the needs for load following down; to allow for variable renewable generation curtailment to balance forecast error and sub-hourly variability. The following three types of operating reserve requirements are considered within the Core Northwest to ensure that in the event of a contingency, sufficient resources are available to respond and stabilize the electric grid:

+ **Spinning reserves:** Modeled as 3% of hourly load in agreement with WECC and NWPP operating standards
+ **Regulation up and down:** Modeled as 1% of hourly load
+ **Load following up and down:** Modeled as 3% of hourly load

Modeling of Imports and Exports

The Northwest RESOLVE model includes a zonal representation of the WECC. In modeling hourly dispatch during representative days, it considers the least-cost dispatch solution across the WECC, based on resource economics, resource operational limits, fuel and carbon prices, operating reserve requirements, and zonal transmission transfer limits. Imports to the CoreNW zone can occur from other neighboring zones; when they do a carbon adder is included for unspecified imports, while specified imports do not receive a carbon adder. Exports from the CoreNW zone may occur as deemed economic by RESOLVE, subject to other model constraints.

Minimum and maximum capacity limits are applied to the zonal representation of transmission between connected zones. These zonal transfer limits are shown in Table 13. Transmission hurdle rates as well as carbon hurdle rates (with regional carbon price adders) are applied to imports and exports.

Table 13. Transmission Capacity Limits between the CoreNW and other Zones

Transmission Constraint	Transmission from	Transmission to	Min Flow (MW)	Max Flow (MW)
CoreNW to OtherNW	CoreNW	OtherNW	-6,036	2,550
CoreNW to CA	CoreNW	CA	-6,820	5,433
CoreNW to SW	CoreNW	SW	0	0
CoreNW to NV	CoreNW	NV	-300	300
CoreNW to RM	CoreNW	RM	0	0

Contracted imports (such as imported coal and/or wind power) are included in the resource adequacy accounting captured in the planning reserve margin constraint. New remote resources include transmission cost adders to deliver them into the CoreNW zone. Additional unspecified imports are not assumed in RESOLVE's resource adequacy accounting.

Additional LSR Dam Power System Benefits (not modeled)

As described in this report, RESOLVE covers replacement of most power services provided by the LSR dams. However, RESOLVE does not model transmission grid operations (power flow, voltage and frequency, dynamic stability, etc.). Therefore, E3 notes that the LSR dams may provide the following additional essential reliability services to the transmission grid. In general, E3 expects that the replacement of these services can be achieved either through siting and operations of the incremental replacement capacity selected or by additional local transmission investments. The scale of these transmission investments requires more detailed study.

- **Reactive power and voltage control**: the LSR dams, like hydropower resources generally in the Northwest, provide significant reactive power capabilities that supports reliable power flow by optimally controlling voltage levels. Replacing this function likely requires siting additional resources with reactive power capabilities in a similar section of the transmission grid as the LSR dams.
- **Frequency response and inertia**: the LSR dams provide both primary and secondary frequency response capabilities. As synchronous generators they also provide system inertia that would be lost if the LSR dams are removed and as other synchronous generators retire. New efforts are underway to allow renewable generators or battery storage to provide "synthetic inertia" (or equivalent fast frequency response services), but this provision has not yet been proven to date at scale. The LSR dams are also highly tolerant of operating during high and low frequency events without sustaining blade damage.

- **Blackstart**: Large hydro resources have the capability to provide black start services when required, though not all hydro plants are chosen to provide this capability.
- **Participation in remedial action schemes**: Hydropower is a robust resource for participation in remedial action schemes because it can withstand being suddenly tripped off-line as part of a RAS action.
- **Short circuit and grounding contribution**: Synchronous generators (like hydropower) provide a large short circuit current that is important for the proper operation of protective relaying schemes.