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EverGREEN 2045

An Energy Mix to Decarbonize Washington State

July 2024

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Abstract

Washington State's future resource mix is likely to be comprised of intermittent renewables and other carbon-free generation including hydropower and potentially advanced small nuclear reactors and enhanced geothermal systems by 2045. In addition, generation will likely consist of wind, solar photovoltaic, batteries, pumped storage hydropower, and an existing nuclear power plant. To assess the cost and stability of the future resource mix, we partnered with X-energy (advanced reactor design) and AltaRock Energy (superhot rock enhanced geothermal system) to gain access to proprietary cost data. After estimating the costs of the two new technologies, we designed plausible future resource mix scenarios to meet Washington State's Clean Energy Transformation Act, which transitions the state to carbon-free generation by 2045. We assessed the cost and stability of the future resource mix with power system analysis tools, finding that revenues are sufficient to cover variable O&M costs for most technologies providing power in 2030 and 2045, but capacity payments or power purchase agreements will likely be necessary for flexible resources, including enhanced geothermal systems and advanced nuclear reactors, to participate in the future resource mix. We recommend several areas for future research including addressing limitations of the current system topology through potential transmission expansion in Washington state, as well as addressing the inherent limitations of the development of prices based on production costs and system constraints to further explore the cost and stability of the future resource mix.

Summary

The Washington State Clean Energy Transformation Act (CETA) transitions Washington State to 100% clean energy by 2045 by eliminating coal generation in 2025, adding a $60/MWh tax on natural gas generation by 2030, and requiring 100% non-emitting generation by 2045 for any electricity serving load in the state. Given these policy requirements, and limitations on new hydropower production, flexible energy resources will need to replace existing fossil-fuel generation in Washington State.

We consider two new flexible, future energy resources: advanced nuclear reactors (ANRs) and superhot rock (SHR) enhanced geothermal systems (EGS), for their potential to provide the needed flexibility for Washington State. Because these technologies are currently under development, limited cost and operational data are available, and analysis needs to be undertaken to examine the stability and economic feasibility of these new resources in Washington State's future resource mix.

To overcome these challenges, we developed an integrated economic and engineering modeling approach to estimate the costs of ANRs and SHR EGS and analyze the stability and economic feasibility of the future resource mix in Washington State using these resources.

We partnered with X-energy, the developer of an ANR, a Gen-IV High-Temperature Gas-cooled Reactor (HTGR) – the Xe-100, and AltaRock Energy, the developer of SHR EGS to gain access to proprietary cost data that we used to develop realistic cost estimates. With those estimates we designed future resource mix scenarios that will meet the policy requirements of Washington's CETA and include likely deployments of the two new technologies in Washington and Oregon. We then used power systems analysis tools (production cost modeling [PCM] and transient stability analysis [TSA]) to examine the cost and stability of the future resource mix. Using the value of services earned in the future resource mix, we investigated the economic feasibility of ANRs and SHR EGSs.

We find that the SHR EGSs have a levelized cost of electricity that ranges from $45 to $56 depending on the availability of incentives, and ANRs have a levelized cost of electricity that ranges from $48 to $59, depending on the availability of subsidies. At these costs, we find that these new technologies will likely need capacity payments of up to $38 for SHR EGS and for ANRs, depending on the future resource mix scenarios. However, the need for capacity payments or power purchase agreements (PPAs) was identified for most resources in the future resource mix (when revenues were compared to the levelized costs of electricity). We also find that there were other benefits to incorporating these flexible resources as they contribute to reduced generation costs and reduced carbon dioxide (CO_2) emissions in the future resource mix, and in some scenarios, reduced congestion and price volatility. Incorporating these new technologies also led to a stable power system across future resource mix scenarios.

Our research contributes to our understanding of the economic feasibility of the future resource mix in Washington State as well as the role of two future technologies that could provide valuable flexibility services. More detailed analyses incorporating transmission upgrades, and strategic behavior could provide Washington State and electricity participants with a more complete understanding of the potential challenges and solutions to achieving clean-energy policy requirements.

Acknowledgments

This research was supported by the Energy and Environment Mission Seed, under the Laboratory Directed Research and Development (LDRD) Program at Pacific Northwest National Laboratory (PNNL). PNNL is a multi-program national laboratory operated for the U.S. Department of Energy (DOE) by Battelle Memorial Institute under Contract No. DE-AC05-76RL01830. We want to thank AltaRock Energy and X-energy for providing us with the information required to produce the cost estimates.

Abbreviations and Acronyms

AC	alternating current
ANR	advanced nuclear reactor
ADS	Anchor Data Set
BEA	Bureau of Economic Analysis
CETA	Clean Energy Transformation Act
DC	direct current
DOE	Department of Energy
EGS	enhanced geothermal system
EIA	Energy Information Administration
GDP	Gross Domestic Product
GHG	greenhouse gas
LCOE	levelized cost of electricity
LMP	locational marginal price
O&M	operations and maintenance
OPF	optimal power flow
PCM	production cost model
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
SHR	superhot rock
TSA	transient stability analysis
VRE	variable renewable energy
WECC	Western Electric Coordinating Council

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1.0 Introduction

With clean energy policies penalizing or eliminating traditional, emissions-intensive coal or natural gas power, the flexibility of generating resources may be at a premium in the future resource mix. In this research we (Pacific Northwest National Laboratory [PNNL]) partner with two leading developers of new flexible technologies, advanced nuclear reactors (ANRs) and superhot rock enhanced geothermal systems (SHR EGSs) for proprietary cost data and incorporate these resources into our integrated economic and engineering modeling approach to investigate the costs and stability of the future resource mix in Washington state.

1.1 Purpose and Scope

The Washington State Clean Energy Transformation Act (CETA) transitions Washington state to a carbon-free electricity-generation portfolio by 2045. With coal generation eliminated in 2025, and a $60/MWh tax on natural gas power generation by 2030, non-emitting, flexible energy resources will need to replace existing coal and natural gas generation. Although Washington's generation portfolio already contains substantial hydropower, new hydropower generation will be very limited and only allowed under tight restrictions. Further, because hydropower is constrained at certain times of the year, and wind and solar power are imperfectly correlated with net load, the flexibility of generating resources will be at a premium. Two future energy resources—ANRs and SHR EGSs—may be able to provide that needed flexibility. However, analysis needs to be undertaken to understand the stability and economic feasibility of Washington's future resource mix with ANRs and SHR EGSs.

Adding to the challenge is that there are many issues associated with the available cost data for ANRs and SHR EGSs. Costs are specific to locations and most costs provided publicly are only for the power plant, which excludes interconnection costs. As an example, the U.S. Energy Information Administration (EIA 2021) indicates that new SHR EGSs cost $36/MWh, including average interconnection costs. Lazard (2021) indicates costs for SHR EGSs range from $56–$93/MWh, excluding interconnection costs. For ANRs, a recent report by Weimar et al. (2021) found that a small modular reactor at the Washington State Hanford Site could produce electricity in the $55/MWh range for an nth-of-a-kind facility, but the first of its kind has yet to be built. Lazard (2021) cost estimates for ANRs range from $131–$204/MWh, again excluding interconnection costs. EIA and Lazard's different costs point to a need for determining the real costs of these technologies. In support of this conclusion, Mignacca and Locatelli (2020) indicated a need for further study of the costs of ANRs.

To address these challenges, we developed an integrated economic and engineering modeling approach to estimate the costs of ANRs and SHR EGSs and analyze the stability and economic feasibility of the future resource mix for Washington State using these resources, as will be further discussed in Section 3.0. To overcome cost data limitations, we partnered with X-energy, the developer of an ANR, a Gen-IV High-Temperature Gas-cooled Reactor (HTGR) – the Xe-100, and AltaRock Energy, the developer of an SHR EGS for proprietary cost and operational data, which we then used to estimate the costs of these new technologies. After estimating the costs of these two new technologies, we designed plausible future resource mix scenarios to meet Washington State's CETA. We then used power system analysis tools to investigate the production costs, as well the stability (in terms of reactive power, voltage, frequency, and inertia) of the future resource mix. We determined the economic feasibility of ANRs and EGSs using the value of services provided, as will be further discussed in Section 4.0. An overview of our integrated economic and engineering modeling approach is provided in Figure 1.

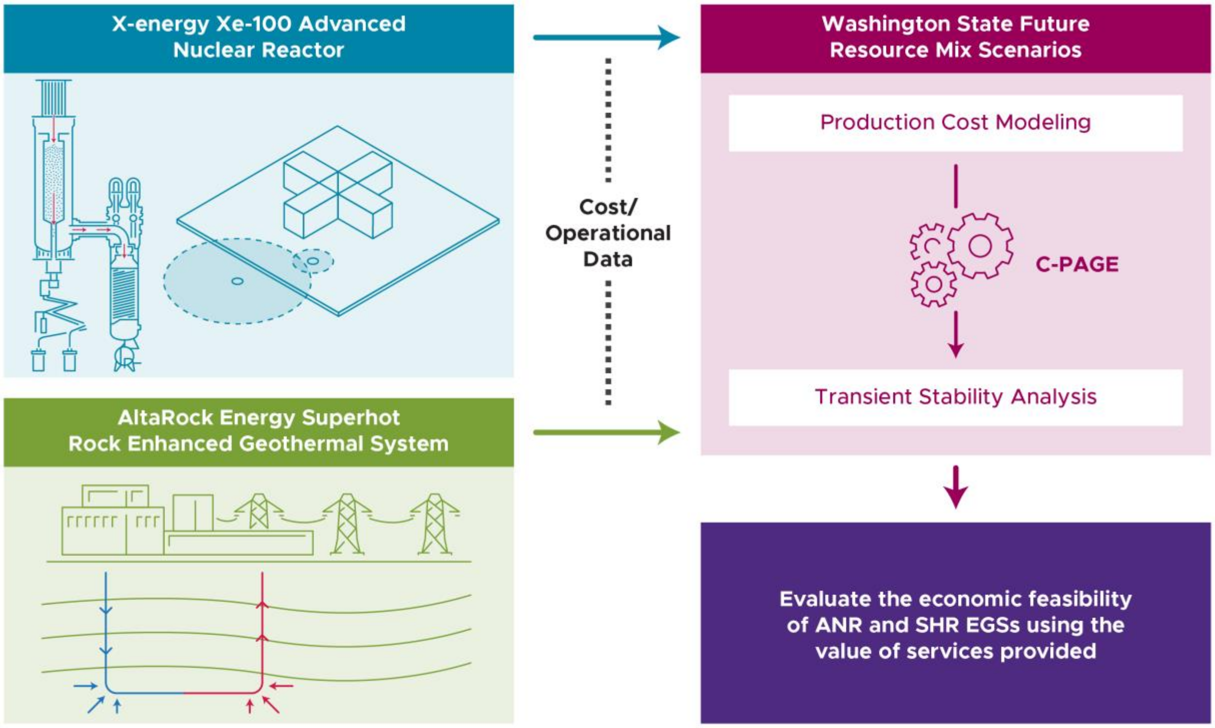

Figure 1: Integrated Economic and Engineering Modeling Framework

Our research design has several important assumptions and limitations. First, due to the availability of both direct current (DC) and alternating current (AC) power-flow models, we use the 2028 WECC planning model as our base case and build from this case for the 2030 and 2045 future resource mix scenarios. To the extent that the 2028 WECC planning model differs significantly from the actual WECC system in 2030,[1] our results will be biased. Second, as we assess economic feasibility given the value of services provided by the PCM; pricing is based on variable production costs and constraints in the system, rather than strategic bids from market participants.[2] Third, we created a step-up interconnection system from low voltage to high voltage for the added supply to support the integration of 100% renewable power for power flow analysis.

Although there are important limitations to our research design, our research contributes to our understanding of the economic feasibility of the future resource mix in Washington State as well as the role and economic feasibility of two future technologies that could provide valuable flexibility services. In Section 2.0, we provide background on the Washington State CETA and its key compliance requirements and milestones toward achieving 100% clean energy by 2045. We incorporate these key policy actions in our future resource mix scenarios. In Section 3.0, we provide an overview of our methodology including our approach to estimating costs for ANRs and SHR EGSs, the design of our future resource mix scenarios, our power systems modeling approach, and our approach to estimating the economic feasibility of the two new technologies

[1] The WECC 2028 planning model differs slightly from the WECC 2030 planning model in terms of installed renewable capacity. For example, over 4,500 MW of onshore wind was added to BPA in the 2030 planning model, and 400 MW was added to PGE. See Appendix B or the 2030 release notes for more details (WECC, 2021).

[2] Strategic behavior implies market participants may at-times bid at prices above their marginal costs, exercising market power.

given the value of services earned in the future resource mix. In Section 4.0, we provide the results for our cost estimates, power systems analysis, and economic feasibility of the future resource mix and new technologies. Section 5.0 concludes with a discussion of the implications of our results for the future resource mix in Washington State. The appendix contains an example of the nuclear cost data questionnaire provided to our industry partner, X-energy.

2.0 Background on the Washington State Clean Energy Transformation Act

The Washington CETA, signed into law in 2019 with the passage of Senate Bill 5116, transitions Washington to carbon-free generation by 2045 (SB 5116, 2019). The Act requires electric utilities serving retail customers in Washington to eliminate coal generation from their generation portfolio by December 31, 2025; be GHG neutral by January 1, 2030; and be 100% clean energy (renewables and non-emitting resources) by January 1, 2045, as shown in Figure 2.

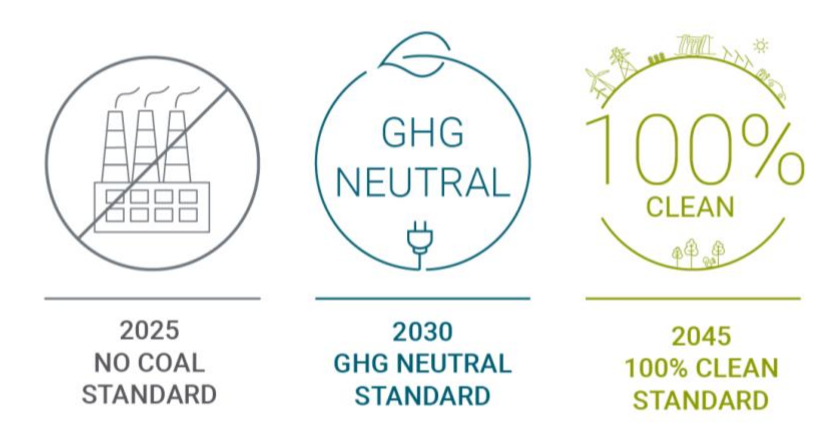

Figure 2. Washington's Clean Energy Transformation Act Standards (Source: WA State Department of Commerce)

To meet these requirements, penalties in the form of alternative compliance payments must be made for the 2025 and 2030 standards. There is no provision for offsets for the 2045 standard. Major requirements and penalties of the CETA are listed in Table 1. We incorporated these key requirements and alternative compliance payments in our design of future resource mix scenarios and analysis of those scenarios.

In our analysis of the future resource mix in Washington State, we modeled the entire WECC system, but only include Oregon and Washington in our solution set for reporting results. This decision was made because the SHR EGS will be potentially located in Oregon. However, future clean-energy policy requirements are only modeled for Washington State.

Table 1. Washington State Clean Energy Transformation Act Standards and Alternative Compliance Payments

Requirement	Alternative Compliance Payments
Each electric utility must eliminate coal-fired resources from its allocation of electricity by December 31, 2025	If not eliminated, the electric utility or affected market customer must pay an administrative penalty of $0.150/kWh for coal-fired resources. Penalties will be adjusted on a biennial basis according to the rate of change in inflation (GDP implicit price deflator published by the BEA) starting in 2027.
Retail sales of electricity to WA retail electric customers must be GHG neutral by January 1, 2030	Alternative compliance payments will be paid by the electric utility or affected market customer for each megawatt-hour of electricity used to meet load that is not electricity from a renewable resource or non-emitting electric generation: • $0.150/kWh for coal-based plants • $0.084/kWh for natural gas-based peaking power plants • $0.060/kWh for NGCC Penalties will be adjusted on a biennial basis according to the rate of change in inflation (GDP implicit price deflator published by the BEA) starting in 2027. Hydroelectric generation used to meet this standard may not include new diversions, impoundments, bypass reaches, or expansion of existing reservoirs unless necessary for the operation of a pumped storage facility that does not conflict with existing state or federal fish recovery plans.
Non-emitting electric generation and electricity from renewable resources supply 100% of all sales of electricity to WA retail electric customers by January 1, 2045	There is no provision for offsets for the 2045 standard. Hydroelectric generation used to meet this standard may not include new diversions, impoundments, bypass reaches, or expansion of existing reservoirs unless necessary for the operation of a pumped storage facility that does not conflict with existing state or federal fish recovery plans.

BEA = Bureau of Economic Analysis; GDP = gross domestic product; GHG = greenhouse gas; NGCC = natural gas combined cycle; WA = Washington State.

3.0 Methodology

Our economic and engineering modeling approach comprises four distinct tasks:

1. Estimation of costs of two flexible energy systems: ANRs and SHR EGSs.
2. Design of future resource mix scenarios.
3. Power system analysis including
    a. Variable operating and maintenance (O&M) and fuel costs of the future resource mix using the PCM, and
    b. Analysis of the stability (in terms of reactive power, voltage, frequency, and inertia) of the future resource mix using transient stability analysis (TSA).
4. Evaluation of the economic feasibility of ANRs and SHR EGSs using the value of services provided.

3.1 Estimation of Costs for Advanced Nuclear and Enhanced Geothermal Systems

An eight-step process is used to determine the costs of advanced nuclear and enhanced geothermal costs:

1. Select a specific location for each technology.
2. Develop a design and process flow for each technology.
3. Determine the major equipment required and obtain equipment costs from X-energy and AltaRock Energy.
4. Develop the required balance of plant components.
5. Estimate bill of materials requirements and costs and determine O&M costs.
6. Estimate the electricity output.
7. Estimate the interconnection costs.
8. Determine the $/MWh price point required to meet hurdle rates (rate of return on equity investment).

These steps require the development of a bill of materials, obtaining the costs (prices) of materials and balance of plant components, and estimating the manufacturing and assembly costs for the system components, as well as the system. These costs are then integrated into the power systems analysis tools (PCM and TSA) used to evaluate the final mix of flexible and variable renewable energy (VRE) resources.

3.2 Design of Future Resource Mix Scenarios

Our future resource mix scenarios incorporate key requirements and alternative compliance payments from Washington State's CETA. Because of the network structure of the electricity grid, modeling the future resource mix in Washington for cost and stability requires modeling the entire Western Interconnection. Our future resource mix scenarios modify the WECC 2028 planning model to reflect the expected future resource mix in Washington State in 2030 and 2045. These scenarios reflect the 2030 GHG-neutral standard and 2045 100%-clean-energy standard. We use the WECC 2028 case due to data availability as discussed in the next section. We design several future resource mix scenarios to examine their investment and operational costs. We then evaluate the stability of the future resource mix scenarios under varying penetrations of intermittent renewable resources. Key future resource mix scenarios and assumptions are provided in Table 2.

Table 2. Future Resource Mix Scenarios

Future Resource Mix Scenario	Key Assumptions
Base Case	2028 WECC Planning Model • PCM is the 2028 Anchor Data Set (ADS) Phase 2 V2.0 from WECC (WECC 2019). TSA model is based on power-flow cases for minimum and maximum renewables generation days generated by C-PAGE • Onshore wind capacity 3,025 MW • Conventional nuclear capacity of 1,170 MW

2030 GHG-Neutral Case	2028 WECC Planning Model adjusted for the following:
	• Penalties on any fossil-fuel generation in Washington State or imports of fossil-fuel generation serving Washington load of:
	  – $0.150/kWh for coal-based plants
	  – $0.084/kWh for natural gas-based peaking power plants
	  – $0.060/kWh for natural gas combined cycle plants
	• Onshore wind capacity 3,025 MW
	• Conventional nuclear capacity of 1,185 MW[a]
	• 100.05 MW enhanced geothermal plant (AltaRock Energy) at Newberry Volcano in Oregon
	• 320 MW advanced nuclear plant (4-pack of X-energy Xe-100 reactors each with 80 MW) at Rocky Ford in Eastern Washington

2045 100% Clean Energy Case	2028 WECC Planning Model adjusted for the following:
	• 100% clean energy serving Washington load
	  – 4,569.9 MW of wind capacity was added to WA state with 6,221 MW total serving Washington load
	  – Zero fossil-fired capacity in Washington State or serving Washington load
	  – Conventional nuclear capacity of 1,170 MW (of which 511 MW serves Washington load)
	  – 2,880 MW Advanced Nuclear Capacity (in addition to the three reactors listed below, for a total of 3,840 MW) serving Washington load
	• 1 GW enhanced geothermal plant (AltaRock Energy) at Newberry Volcano in Oregon
	• 320 MW advanced nuclear plant (4-pack of X-energy Xe-100 reactors each with 80 MW) at Rocky Ford in Eastern Washington
	• 320 MW advanced nuclear plant (4-pack of X-energy Xe-100 reactors each with 80 MW) at Hanford Site 1 in Eastern Washington
	• 320 MW advanced nuclear plant (4-pack of X-energy Xe-100 reactors each with 80 MW) at Centralia in Central Washington

[a]Conventional nuclear power capacity is uprated (in error) to 1,185 MW instead of 1,170 MW in the 2030 scenario. Conventional nuclear power capacity remains at 1,170 MW for the 2045 scenario although more advanced nuclear capacity is added to the system.

3.2.1 2030 Greenhouse Gas Neutral Future Resource Mix

The first future resource mix scenario represents the Washington State future resource mix in 2030 under the GHG-neutral standard. We incorporated key elements including the elimination of coal plants in Washington State, a carbon tax (to reflect the alternative compliance payment) for any generation serving Washington demand (load) of \$0.150/kWh for coal-based generation, \$0.084/kWh for natural gas-based peaking power plants, \$0.060/kWh for natural gas combined cycle generation.[1] We also do not allow for any new hydropower plants.

We add two new plants to the WECC 2028 planning model, a 100.5 MW enhanced geothermal plant at Newberry Volcano in Oregon State and a 320 MW advanced modular reactor plant in Grant County, Washington. Both plants are added at existing nodes that do not require additional transmission investments or network changes.[2]

We assess investment and operational costs for the 2030 GHG-neutral standard using the above-designed scenario. We examine the stability of the above-designed scenario for the days with the minimum percentage of wind and solar resources and highest percentage of wind and solar resources.

3.2.2 2045 100% Clean Energy Future Resource Mix

The second future resource mix scenario represents Washington State's future resource mix in 2045 under the 100% clean-energy standard, where 100% renewables and non-emitting resources serve the Washington State load. For this scenario, we scale up wind production, solar production, and advanced nuclear production to account for the retirement of all fossil-based thermal units.

The methodology for determining the optimal placement of clean energy resources for the 2045 100% Clean Energy Case was developed with the goal of adding sufficient clean energy supply to meet the 100% clean energy standard without upgrading the existing transmission system. Washington clean energy needs were determined on a monthly basis by subtracting existing clean energy supply from load. New clean energy supply resources were then added to meet monthly load needs at minimum cost. New clean energy supply locations were determined from previous analyses of supply locations within WECC that would minimize transmission congestion and variable renewable energy spillage. Once monthly load needs were met, the new supply was added to the PCM to determine if the added supply was sufficient to meet hourly load needs for Washington State.

As transmission constraints in Washington state primarily occur when moving power west (across the Cascades to the I-5 corridor) and north/south (along the 1-5 corridor), ANRs were added at existing sites that were built to support baseload supply (for example, ANRs were added at sites near the existing Columbia generating station, the retired Centralia coal plant site, and the site of a failed nuclear development near Aberdeen, WA). New wind power supply was added in the Lower Snake River region, along the Columbia Gorge, and on the west side of the Cascades near the coast in Washington. In addition, new wind power supply from Montana, which is winter peaking and can support Washington State winter peak load, was also added

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[1] Penalties are modeled as an addition to variable O&M cost in the PCM. To allow for analysis in 2022 dollars, we do not escalate alternative compliance payments at the rate of inflation.

[2] We selected substations with high voltage (500 kV) and assumed there would be sufficient head room for capacity to be injected into the network.

and assumed to serve Washington load. Solar PV was also added along the Lower Snake region, in the Hanford site area, and the retired Centralia coal plant site area. Four-hour battery energy storage was distributed with added solar generation. New, closed-loop pumped storage hydropower was added on the east side of the Cascades (where surplus wind and solar exist), as well as along the Columbia Gorge and Mid-Columbia area.

Changes in the two new flexible energy systems reflect their potential expansion: the SHR EGS expands to 1 GW at Newberry Volcano in Oregon and in addition to the 320 MW advanced modular reactor plant at a potential site in Grant County, Washington, we assume two additional 320 MW advanced modular reactor plants are operational—one at the Hanford Site and one at Centralia, Washington. We include an additional 2,880 MW of flexible advanced nuclear capacity to make up for the deficit in thermal generation needed to reliably operate the electricity grid in Washington State (we convert any remaining natural gas plants in Washington State to ANRs). All plants are added at existing nodes that do not require additional transmission investments or network changes. In total, we added 57 non-emitting generation units and turned off fossil-fuel powered generators across the WECC footprint. We added 13 onshore wind power units totaling 4,569.9 MW, six utility-scale PV units totaling 1,923.8 MW, 12 advanced nuclear reactor units totaling 3,840 MW, eight pumped hydro units totaling 3,000 MW (with 14-hr storage), and 11 battery storage units (with 4-hr storage) totaling 1,980 MW. Owing to the operational architecture of power utilities and balancing authorities in Washington state, we defined Washington state share of the generation and loads. Particularly, this share captures various power contracts of balancing authorities, including those with generators located outside Washington state.

We assessed investment and operational costs for the 2045 100%-clean-energy standard using the above-designed scenario. For reference this case is called the 2045 100% Clean Energy Case. In our power-flow modeling, we examined the stability of the 2045 100% Clean Energy Case for the day with the highest percentage of wind and solar resources.

3.3 Power System Analysis

Understanding of investment decisions beyond operational costs is critical to reliable power system operations. Power system analysis tools specialize in modeling specific features of the grid. For example, while production costing is very good at capturing hourly operational decisions and costs over the course of a year, it uses a simplified DC power-flow model that only captures the real power flows on the system and usually focuses on near-term resource allocation. However, to truly study the impact of VRE resources on the power system, especially for cases in which there is a high penetration of VRE such as wind and solar, AC power-flow and stability analyses are needed in addition to production cost modeling. AC power flow is necessary to examine the impact of VRE resources on reactive power flows and voltages in the system and serves as the base for both optimal power flow (OPF) and TSA. However, each type of analysis has its limitations. OPF covers optimal generator dispatch, but not how this dispatch affects system stability. Transient simulations do not capture investment or operational costs, rather it demonstrates the system operation during generation, load, and resource contingencies.

From a power systems perspective, our modeling approach uses both PCM and TSA. First, we adjust the production cost (DC power-flow) model to reflect our future resource mix scenarios. This involves adding ANRs and SHR EGS plants at key locations. No changes are made to existing transmission in the production cost model, but generation and loads are changed as described in future resource mix scenarios in Section 3.2.

Our TSA uses a staged approach to answer two main questions: 1) how do new, flexible resources contribute to grid stability, and 2) can a stable electric grid be achieved with 100% clean energy resources. To answer the first question, we analyze how the addition of new, flexible clean energy resources (ANRs and SHR EGSs) contribute to grid stability under increasing penetration of renewable resources starting with the 2030 (GHG Neutral Scenario) and considering the planned expansion of flexible resources for 2045. For the 2030 GHG Neutral standard, parallel changes are made to the DC power-flow model and AC power-flow cases from the WECC 2028 base case (generated by C-PAGE, a PNNL-developed energy system modeling tool which automatically converts the WECC 2028 base case into corresponding converged AC power-flow cases) to reflect the addition of new, flexible resources. To answer the second question, we analyze if our 100% Clean Energy Scenario is stable. We use C-PAGE to incorporate changes from the DC power-flow model to the AC power-flow case for the 2045 100% Clean Energy Case. Due to the addition of 57 generators in the 100% clean energy case, we limit our analysis to the bus with the largest addition of wind generation capacity (1225 MW). A step-up interconnection system (buses and transformers) from low voltage to high voltage are added to support supply additions in the AC power-flow model.

With each power system analysis tool, we examine several criteria, discussed in Sections 3.3.1 and 3.3.2, to evaluate the cost and stability of the future resource mix scenario.

3.3.1 Production Cost Modeling Criteria

With the PCM, we validate the model for each scenario for reasonableness in system operations after generation additions, specifically evaluating (1) unserved load, and (2) extreme locational marginal prices. For the impacts of new additions, we study the following: (1) resource dispatch in Washington (and the WECC system) across a 1-year timeframe under different scenarios, specifically considering dispatch/use of hydropower, ANRs, SHR EGSs, and energy storage units and curtailments of variable renewable energy resources (on-shore wind power units); (2) production costs of the Washington system across scenarios relative to the WECC 2028 planning model; and (3) carbon emissions and costs across scenarios relative to the WECC 2028 planning model.

3.3.2 Transient Stability Analysis Criteria

3.3.2.1 Transient Stability

Large-disturbance rotor angle stability or transient stability, as it is commonly referred to, is concerned with the ability of the power system to maintain synchronism when subjected to a severe disturbance, such as a short circuit on a transmission line. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship (Kundur 2004). This is reflected in frequency response as well as voltage response waveforms in terms of oscillations.

3.3.2.2 Experimental Setup

Our TSA analysis involves (1) exposing the system to a large N-2 contingency (such as the loss of 2 assets out of N assets), e.g., loss of a major generator; (2) observing the response of the system such as voltage support and frequency nadir;[1] (3) comparing the response of the system with and without ANRs and SHR EGSs included at previously selected locations within the WECC 2028 planning model to assess how the new, flexible resources contribute to system stability; and (4) comparing the response of the system with and without a large addition of variable, renewable energy resources to assess system stability under high renewables penetration. To analyze the modified system for its transient stability, an experiment was conducted by tripping the two largest generator units (each 1,250MW unit) in the WECC system, also known as the Palo Verde contingency.

The results are analyzed in terms of voltage and frequency response and corresponding limit violations and system inertia. Comparison of the models has been done with and without the new generation units. Comparison results are presented on local (Northwest area) transient response and system wide response.

3.4 Economic Feasibility

To determine the economic feasibility of ANRs and SHR EGSs, the values of services provided by the new flexible generators are obtained from the PCM. From the PCM, we primarily obtain metrics on system costs, because this model provides the cost of generator utilization, including dispatch, variable production cost, revenues, and the hours that the generator is the marginal generator; as well as locational market clearing prices for both energy and ancillary services, and the prices for congestion and losses. The PCM provides the metrics presented in Table 3, which we use as inputs to our economic analysis:

Table 3. Metrics from PCM with Explanations

GridView Metric	Explanation
Revenue (M$)	Revenue from energy and ancillary services markets for each generator, summed for an annual total revenue by technology type, in millions of dollars.
Variable O&M Cost (M$)	Variable O&M costs for each generator, summed for an annual total O&M cost by technology type, in millions of dollars.
Fuel Cost (M$)	Variable fuel costs for each generator, summed for an annual fuel cost by technology type, in millions of dollars.
Cost (M$)	Total variable O&M and fuel costs for each generator, summed for an annual total O&M and fuel cost by technology type, in millions of dollars.
Total Generation (MWh)	Total generation (in MWh) for each generator, summed for an annual total generation by technology type, in millions of dollars.

To examine the economic feasibility of different technology types in the base case, 2030 GHG Neutral Case, and 2045 100% Clean Energy Case, we examine whether revenues are able to cover variable O&M and fuel costs based on the PCM parameters. However, the PCM does not capture total costs in an economic sense because fixed costs from capital investments and fixed O&M are not considered; therefore, we compare revenues to LCOE estimates by technology

[1] Frequency nadir is defined as the minimum value of frequency reached during the transient period.

type from the EIA's Annual Energy Outlook 2023 for new resources entering service in 2028 (in 2022 dollars per megawatt-hour),[1] as well as LCOE estimates developed for ANRs and SHR EGSs in this research.

We note that potential flexibility benefits may not be fully priced in the PCM, because payments to generators for flexible ramping are not captured. However, because we did not see significant increases in prices above the cost of production from increased demand for ancillary services, we did not price this potential benefit.

3.5 Limitations and Simplifying Assumptions

Our research design has several important assumptions and limitations. First, we used the 2028 WECC planning model as a starting point for our power systems analysis but modified the 2028 WECC base case to reflect 2030 GHG-neutral standard and the 2045 100% clean-energy standard. The decision to use the 2028 WECC planning model was based on the availability of both the DC power-flow model and AC power-flow cases developed using C-PAGE, thereby allowing us to start from a stable system. This assumption could create biases to the extent that the 2030 WECC system has significant changes in the underlying resource portfolio and network topology. We highlight important differences between the 2028 and 2030 WECC planning cases in Appendix B. In future research, we recommend the 2030 WECC model be used as a base case.

A second important assumption is how we analyzed the stability of the system. For the 2030 GHG-neutral standard, parallel changes were made to the DC power-flow model and AC power-flow cases from the WECC 2028 base case (for the day with lowest and highest renewables) to reflect the addition of new, flexible resources. For the 2045 100% Clean Energy Case, the DC power-flow dispatch from the day with the highest quantity of renewables was used to generate the AC power-flow case with C-PAGE. However, due to time and budgetary constraints we conducted TSA with the detailed model of system components connected to the bus with the largest addition of wind generation capacity (1225 MW) for the 100% Clean Energy Case. Although this analysis indicates the system is stable, in future research we recommend expanding TSA to the addition of 57 generators from the 100% Clean Energy Case.

Third, because the prices for energy and ancillary services in the PCM are based on variable production costs and constraints in the system, we assessed economic feasibility given the value of these services, rather than strategic bids from market participants. In future research we recommend the development of a bid-based model, which would allow for the analysis of potential price and revenue impacts given more realistic bidding behavior.

Fourth, because the primary limitation of the simplified power-flow case is network constraints; we recommend exploring transmission upgrades (increased capacity and/or additional network lines) to support the integration of 100% renewable power to meet system demand at all hours.

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[1] Available at https://www.eia.gov/outlooks/aeo/electricity_generation/ (accessed 9/21/2023).

4.0 Results

We present results from the four distinct tasks outlined in our methodology: (1) cost estimates for ANRs and SHR EGSs; (2) generation mix for future resource mix scenarios after incorporating Washington State CETA requirements; (3) results of the power system analysis, including the investment and operational costs of the future resource mix from PCM, and the results of the stability (in terms of voltage and frequency response and corresponding limit violations and system inertia) of the future resource mix using TSA; and (4) the economic feasibility of ANRs and SHR EGSs using the value of services provided.

4.1 Estimated Costs for Advanced Nuclear Reactors and Enhanced Geothermal Systems

For both ANRs and SHR EGSs, proprietary designs, process flows, and associated cost components and operational data were obtained through non-disclosure agreements with industry partners. The information was used to develop the levelized cost of electricity (LCOE) estimates for each technology.

4.1.1 Estimated Costs for Advanced Nuclear Reactors

We partnered with X-energy, a nuclear reactor and fuel design engineering company that develops Generation IV high-temperature gas-cooled nuclear reactors, powered by TRISO fuel. X-energy's ANR has a pebble bed design, allowing for online refueling (94% capacity factor), and the design is modular, allowing for 80 MW reactors to be scaled into a “four-pack” 320 MW power plant. The reactor is also highly flexible and allows for cogeneration options. X-energy is part of the U.S. Department of Energy’s Advanced Reactor Demonstration Program. X-energy also has existing partnerships to support the development and commercial demonstration of the first ANR in the U.S. in Washington State.

To develop nth-of-a-kind cost estimates, we provided X-energy with a nuclear cost data questionnaire (available in Appendix A). We then used the G4ECONS nuclear-economic model to develop the LCOE (G4ECONS 2018). Because the G4ECONS nuclear-economic model did not include a model for a reactor similar to the Xe-100 as one of its six modules, proprietary X-energy data, literature review, current uranium market mining, conversion and enrichment costs, as well as PNNL calculations, were used to determine appropriate parameters for the G4ECONS model. Based on these data, and assuming the clean electricity production tax credit available from the Inflation Reduction Act[1] of 1.5 cents per kW (in 1992 dollars, inflation adjusted) for ANRs applies, the LCOE is $48/MWh for an nth-of-its-kind plant. Note that without this incentive the LCOE is $59/MWh.

Variable O&M costs are based on proprietary data provided by X-energy. Other operational parameters are based on proprietary data from X-energy when available and from Columbia Generating Station (scaled for enhanced efficiency of the Xe-100). Ramping capabilities are based on proprietary data provided by X-energy.

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[1] The clean electricity production tax credit of 1.5 cents/kWh (inflation adjusted) per kWh applies for 10 years for facilities placed in service after 12/31/24. The 1.5 cents/kWh assumes prevailing wage and apprenticeship requirements are met. If the ANR is also located in an energy community (brownfield site) the credit increases to 1.65 cents/kWh (Inflation Reduction Act of 2022). We assume the credit does not phase out, i.e., U.S. GHG emissions from electricity are greater than 25% of 2022 emissions.

4.1.2 Estimated Costs for Enhanced Geothermal Systems

We partnered with AltaRock Energy, a technology leader in SHR EGSs to obtain proprietary design, cost, and operational data for use in our analysis. The value proposition behind SHR EGSs is that drilling into superhot rock provides higher steam temperatures and higher turbine efficiency, allowing an SHR EGS to leverage economies of scale not available for current geothermal systems. Because the drilling technology for the depths required to access superhot rock at the proposed site—Newberry Volcano in Oregon—is unproven, financing costs and permitting costs are currently the main limitations to deploying this technology at scale.

To develop cost estimates, we obtained a proprietary levelized cost of energy model from AltaRock for superhot rock. The model contained assumptions about wellfield capital expenditure and power plant capital expenditure based on the literature and proprietary AltaRock models. Financing assumptions were based on AltaRock's expected costs of financing. PNNL made several adjustments to the LCOE model including adjusting the effective tax rate to be inclusive of federal and Oregon State taxes, which affected the weighted average cost of capital[1]; adding insurance costs based on the Department of Energy's Geothermal Electricity Technology Evaluation Model (GETEM)[2]; adding a corporate activities tax, applicable to business revenues over $1 million in Oregon (HB 3427, 2019); adding a depletion allowance of 15% (26 U.S.C. § 613) capped by the value of the property (Oregon Rev. Stat. § 317.374); and adding a Clean Electricity Investment Tax Credit, which is up to 30% of initial capital and added wells with new modifications from the Inflation Reduction Act (Inflation Reduction Act of 2022). The LCOE, inclusive of taxes and incentives, is $45/MWh for an nth-of-its-kind plant. Because the Clean Electricity Investment Tax Credit declines as emissions reduction goals are met, assuming the Clean Electricity Investment Tax Credit does not apply, the LCOE is $56/MWh.

Variable O&M costs are based on proprietary data provided by AltaRock.[3] Ramping capabilities and other operational characteristics are based on the Geysers geothermal plants in California.

4.2 Future Resource Mix Scenarios

We developed resource mix scenarios based on the WECC Anchor Data Set (ADS) Production Cost Model for 2028. This model represents an expected electric system for the 2028 year, developed by WECC and based on inputs from all its member utilities. The model contains a direct current transmission network topology with about 30,000 load and generation buses, including discrete modeling of all major generators across the WECC electric system. This includes the major generation in Washington and Oregon, our states of interest.

[1] The assumed federal tax rate is 21%, because it is currently unclear whether the tentative minimum tax of 15% from the Inflation Reduction Act would apply (Inflation Reduction Act of 2022).
[2] The GETEM model is available at https://www.energy.gov/eere/geothermal/geothermal-electricity-technology-evaluation-model (accessed 9/7/2022).
[3] We noted an issue with the calculation of variable O&M costs that was identified too late to be included in this analysis. O&M costs were estimated based on a percentage of capital costs, but because the variable quantity of power produced declines over time, O&M costs are higher per unit of power produced at the end of the project than at the beginning of the project. O&M costs are a discounted average of O&M costs over the life of the project, but they are discounted at the after-tax weighted average cost of capital (WACC) when O&M costs should be discounted at the pre-tax WACC. This error could understate O&M costs; however, it was noted that AltaRock's assumption of O&M costs as a percent of capital expenditure was roughly 1% higher than typical geothermal O&M costs (based on GETEM).

Starting from the base case – 2028 year, we build out different generation mixes for the different scenarios, as described below. The Base Case in Washington features a significant proportion of hydroelectricity, nearly 70%, in line with the large federal system on the Columbia River. In addition, natural gas makes another 12% of installed capacity (providing balancing to the system), 4% nuclear capacity, and about 10% wind capacity, with smaller amounts of renewables like solar and biomass filling the remaining capacity for a total installed capacity of 29,715 MW.

4.2.1 2030 GHG-Neutral Case

Building on the Base Case, 320 MW of ANR capacity was added in Washington and 100 MW of enhanced geothermal energy was added in Oregon for a total new installed capacity of 29,393 MW. The MWh served for full year simulation was 147,843,869 MWh. This is coupled with an added carbon penalty applied to fossil generation for retail sales within Washington associated with carbon-emitting resources, as discussed above (Figure 3).

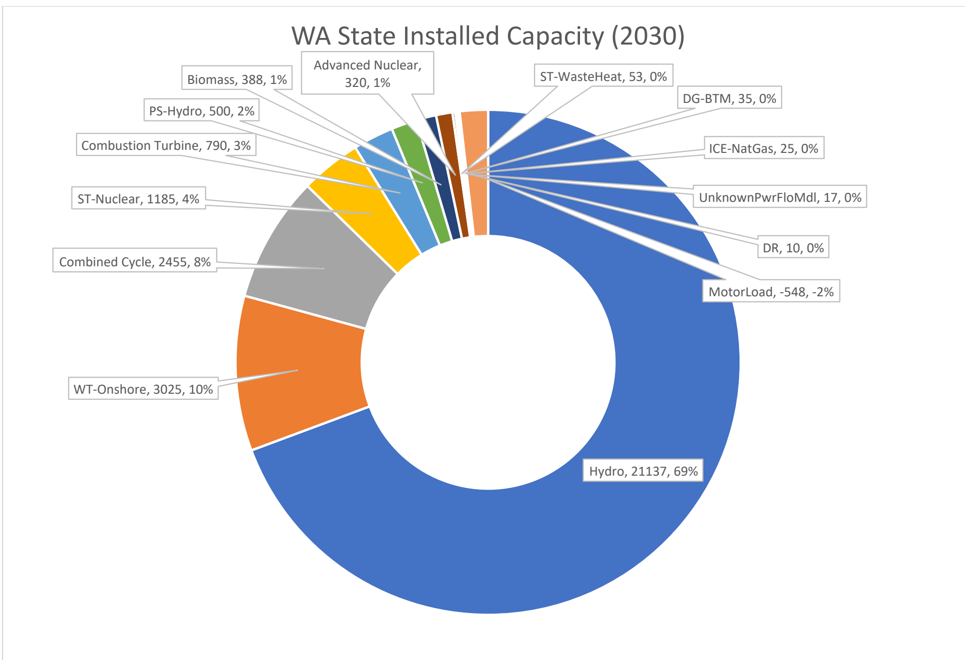


Figure 3. Washington State Installed Generation Capacity (2030) (MW, %)

4.2.2 2045 100% Clean Energy Case

Building on the 2030 GHG-Neutral Case, the 2045 Planning Case includes a significant further buildout of ANR capacity (3,840 MW) and SHR EGSs. Figure 4 displays the installed capacity serving Washington load (37,558 MW). The MWh served for full year simulation was 132,947,291 MWh. For the 2045 100% Clean Energy Case we report the installed capacity serving Washington load as clean energy resources were specifically attributed to serve Washington load in the PCM to verify compliance with the 2045 100% clean energy standard in Washington state.

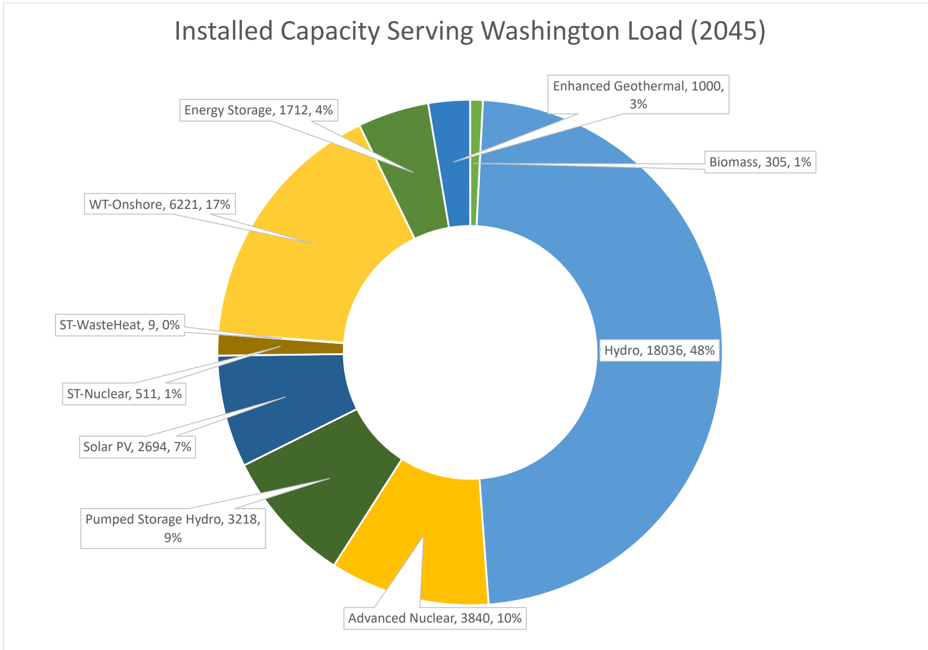


Figure 4: Installed Capacity Serving Washington Load (2045) (MW, %)

4.3 Power System Analysis

4.3.1 Production Cost Modeling

At a high level, and as discussed in more detail above, the PCM dispatches available generation units to meet demand on an hourly basis over the course of a year. The PCM model optimizes the WECC system, and the results are analyzed for Washington state.[1] The model is intended to represent actual system operations and permit system planners and operators to model existing operations as well as permutations to those operations. Inputs to the model include detailed cost and operational data (e.g., heat rates and ramping capability) as well as demand and grid service requirements. In the 2045 100% Clean Energy Case, an additional constraint was added to the PCM to incentivize Washington supply to serve Washington load.

Accordingly, changes to the system, such as new generation resources, can be evaluated from both technical integration and valuation perspectives. That is what we do here to highlight the technical potential and system cost impact of the addition of wind power plants, ANR, SHR EGS, and energy storage units. As expected, the permutations of generation resource allocation have impacts on the operation of the system, including dispatch, costs, and power flows (again DC power flow in this case, with the more detailed AC power-flow analysis in the next section). This section covers system-level PCM results relative to the Base Case. Section 4.4 then

[1] The PCM model optimizes the system through several iterations using mixed integer optimization. In the first pass, hydropower is dispatched to meet net load (which is load net of wind and solar generation). In the second pass, energy storage is dispatched based on a proxy hourly energy price (from a simple dispatch). In the third pass, dispatchable supply is committed and dispatched (e.g., hydropower units with hydro-thermal coordination can redispatch based on locational marginal prices), and spillage is allowed at a user set dispatch cost for hydropower, wind, and solar resources. In the fourth pass, the full day (24 hours) is optimized; available dispatchable supply can be re-dispatched within operating parameters for the 24-hour optimization.

evaluates economic feasibility of existing and added generation resources. Section 4.3.2 presents the transient analysis of the system with existing and added generators.

Table 4 identifies system impacts associated with the Base Case, 2030 GHG Neutral Case and 2045 100% Clean Energy Case. As is evident from the table, the model results show a reduction in generation cost relative to the Base Case. This is expected given reduced fossil-fuel use, replaced by nuclear and geothermal generation. The changes in carbon dioxide (CO_2) emissions across the region are greatest in the 2045 100% Clean Energy Case given the enforcement of 100% clean-energy policies in Washington. Remaining emissions in the 2045 100% Clean Energy Case come from a small amount of biomass in Washington.

Table 4. PCM System Impacts of Scenarios for Washington and Oregon ($2018)

Scenario	Generation Cost (M$)	Simple Avg. LMP ($/MWh)	CO_2 Emissions (short ton)	Unserved Load (MWh)	Curtailment (MWh)
Base[a]	1,236	27.0	22,898,849	0	155,158
2030 GHG Neutral[a]	876	39	17,205,218	94	129,328
	-29%	47%	-25%		-17%
2045 100% Clean Energy Case[b]	349	16	1,480,651	0	2,188,931
	-72%	-41 %	-94%		1,311%

M$ = Million Dollars, $/MWh = Dollars per Megawatt Hour, LMP = Locational Marginal Price.
[a] The Base Case and 2030 GHG Neutral Case detail is from the DOPD, GCPD, AVA, PGE, PSEI, SCL, TPWR, BPAT, and CHPD balancing areas in the PCM model, which provide electricity in both Washington and Oregon.
[b] The 2045 100% Clean Energy case detail is from the share of resources attributed to serve Washington load. This distinction is due to a PCM modeling approach made to ensure 100% clean energy serves Washington load.

The results for average locational marginal price (LMP) do not follow the same pattern, however, we see an increase in average LMP for the 2030 GHG-Neutral Case but a decrease in the 2045 100% Clean Energy Case, despite overall reductions in generation cost across the region. The increases in LMP for 2030 GHG-Neutral Case may be a result of the increased cost (due to penalties in high-cost generators to meet the generation-load balance, whose dispatch that set marginal price) and unavailability of natural gas generation and balancing costs (from high-cost generators and energy storage units). In the 2045 Clean Energy Case, the added ANRs might have suppressed some of this generation and price volatility and reduced the LMP as compared to 2030 GHG Neutral Case. Washington and Oregon are not in an organized market and do not have pricing nodes in which LMPs would be representative of the localized cost of energy and localized congestion. Nonetheless, the model develops LMPs associated with different node points, which are often transmission substations in the model. As in a market environment, the LMPs represent the localized generation and congestion prices associated with the transmission system within the model. Effectively, the prices are a representation of the cost of electricity and costs of congestion to serve load in different nodes.

It is important to note that the model does not account for capital costs, only operational costs, assuming an as-built system. Given that it is an operational model, adding in costs incurred regardless of dispatch is not standard practice, except for fixed maintenance costs, which are included to provide an accurate picture of operational costs.

Finally, we see a reduction in renewable curtailment in the 2030 GHG Neutral Case by about 17%, but a significant increase of over 1,000% relative to the Base Case for the 2045 100% Clean Energy Case. These results are in line with expectations; the added ANR and SHR EGS generation resources in the 2030 GHG Neutral Case add system flexibility, permitting incorporation of additional renewables. In the 2045 100% Clean Energy Case, the removal of flexibility by way of fossil retirements and added new renewables yields increased curtailment. This can be expected relative to the Base Case due to inability to dispatch variable renewable energy supply. Added energy storage and longer duration pumped hydro storage is utilized to balance variable renewable energy supply in the 2045 100% Clean Energy Case. That said, we still see a significant reduction in CO_2 emissions.

Changes in the generation mix are another lens by which to evaluate PCM results. These changes are presented as a part of the economic feasibility analysis in Section 4.4. The changes in generation are in line with the changes made to the system in each of the scenarios: hydroelectric generation continues to dominate, with nuclear, geothermal and wind providing significant energy. The overall reduction in generation costs across cases bodes well for the operational cost benefits associated with a move to Washington's clean energy goals.

4.3.2 Transient Stability Analysis

Our TSA uses a staged approach to answer two main questions: 1) how do new, flexible resources contribute to grid stability, and 2) can a stable electric grid be achieved with 100% clean energy resources.

4.3.2.1 Contribution of New Technologies to Grid Stability

To operationalize our first question, we analyzed the day from the 2028 Base Case with the minimum percentage of renewables serving load, and the day from the 2028 Base Case with the maximum percentage of renewables serving load. We adjusted each case to reflect the addition of new, flexible resources for the 2030 GHG Neutral Case (as described in detail in Section 3.2 and assessed how flexible technologies contribute to system stability by comparing 2028 Base Case results to the 2030 GHG Neutral Case results.

To assess how new, flexible technologies contribute to system stability under increasing penetration of renewable resources we then used an approximated dispatch based on the day with the maximum percentage of renewables serving load (as described in Table 5). We adjusted the dispatch to reflect the amount of wind generation that can be added at existing wind generation sites in Washington State and maintain a stable system (an additional 1,150 MWh, as determined by C-PAGE) as well as the planned expansion of new ANRs and SHR EGSs in 2045 as discussed in 3.2.2. We assessed how flexible technologies contribute to system stability by comparing the 2028 Base Case (Adjusted) results to the 2045 Expanded Renewables results. A total of four scenarios are considered:

1. A minimum renewable power generation scenario (3.9% of load served by wind and solar), (C-PAGE case 5828, generated by C-PAGE from the 2028 WECC model, this is the day with the lowest percent of load served by wind and solar).

2. A maximum renewable generation scenario (50% of load served by wind and solar generation), (C-PAGE case 2080, generated by C-PAGE from the 2028 WECC model, this is the day with the highest percent of load served by wind and solar).

3. For the 2030 GHG-Neutral Case two system configuration files considered with corresponding dynamic models:

    (A) without any ANRs or SHR EGSs (Base Case), and

    (B) with four ANRs, each of 80 MW capacity (4X80MW) and one SHR EGS (1X100 MW) (2030 GHG-Neutral Case). The scenarios are described in Table 5.

4. For the Expanded Renewables Case two system configuration files considered with corresponding dynamic models:

    (A) without any ANRs or SHR EGSs but with 1,150 MWh added wind generation at existing wind sites (Base Case [Adjusted]), and

    (B) with twelve ANRs, each of 80 MW capacity (12X80MW) and 10 SHR EGS (10X100 MW) as planned from the 2045 100% Clean Energy Case. The scenarios are described in Table 5.

Table 5. Transient Stability Analysis Scenarios for Assessing New Technology Contributions to Grid Stability

Future Resource Mix Scenario	Transient Stability Analysis
Base Case	• C-PAGE Case 5828 with the minimum renewable generation from the WECC 2028 planning model • C-Page Case 2080 with the maximum renewable generation from the WECC 2028 planning model
2030 GHG-Neutral Case	• C-PAGE Case 5828 with the minimum renewable generation from the WECC 2028 planning model, modified to reflect 2030 GHG-neutral scenario assumptions • C-PAGE Case 2080 with the maximum renewable generation from the WECC 2028 planning model, modeled to reflect 2030 GHG-neutral scenario assumptions
Expanded Renewables	• C-PAGE Case 2080 with the maximum renewable generation from the WECC 2028 planning model, adjusted to add 1,150 MWh of wind at existing wind locations, modeled to reflect 2045 ANR and SHR EGS planned expansions

Contribution of Flexible Technologies to Grid Stability in the 2030 GHG-Neutral Case

With new investments, four additional 13.8 kV buses are created and added to the Rocky Ford bus (230 kV) through step-up transformers. Each of these buses is connected to ANR units of 80 MW capacity each. Inertia calculations are done on a 100 MVA base. Dynamic models for each unit are added in accordance with ANR specifications. Similarly, one 13.8 kV bus is created near the La Pine bus for adding the geothermal units each of 100 MW capacity through a transformer. After getting a steady-state power-flow solution from the system, a 30-second transient simulation run is conducted in PowerWorld software. In this simulation, a double Palo Verde contingency is created by applying fault and then unit tripping at 15 seconds and 17 seconds, respectively. This creates a large generation loss across the WECC in the simulation and transient response is recorded. The following figures and tables present a comparison of system strengths and responses for the Base Case (2028) (Panel A) and the 2030 GHG-Neutral

Case (Panel B) under the contingency events and two different renewable generation scenarios (minimum [the least solar and wind day] and maximum renewables generation [the day with the most wind and solar]). From the voltage profiles obtained due to the contingency, with the added advanced nuclear and enhanced geothermal generation, the system response remained stable even after applying the contingency and did not cause any unstable modes of the system, Figure 5Figure 7 system inertia was improved by adding new advanced nuclear and enhanced geothermal generation, as shown in Table 6 for the maximum renewables case, and in Table 7 for the minimum renewables case. A histogram plot of maximum and minimum limit violations across buses during the post-contingency period is also presented in Figure 6 for the maximum renewables case, and in Figure 8 for the minimum renewables case. Figures 6 and 8 show that with the new system (i.e., the 2030 GHG-Neutral Case), the voltage limit violations across the Northwest remained similar to the base case across both minimum and maximum renewables generation cases. This implies the new system configuration did not introduce any new limit violations across the region, and the system remained stable with more generation contributing to system inertia. The following results are presented for both the minimum and maximum renewable generation cases.

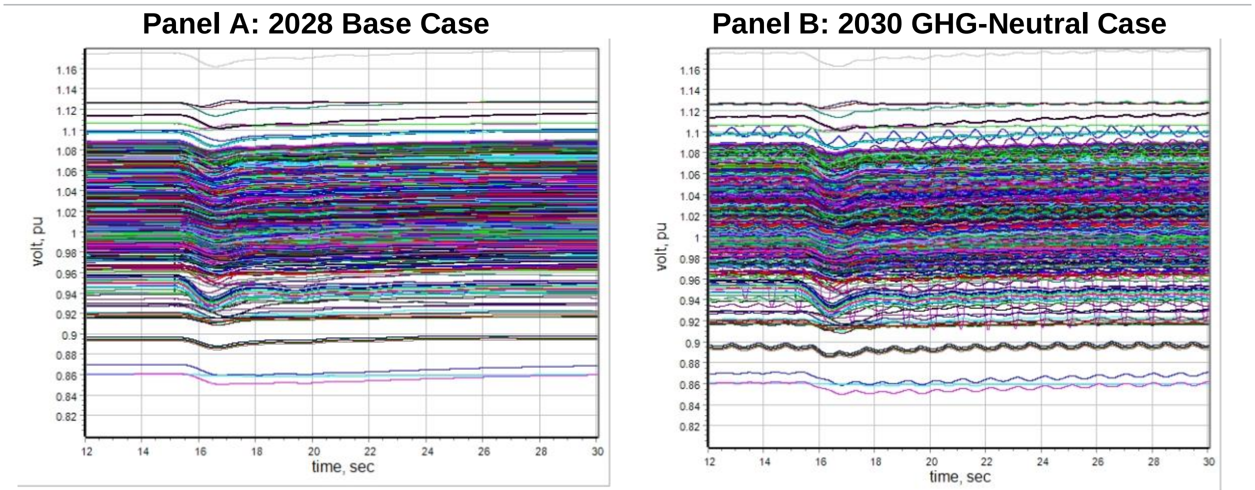


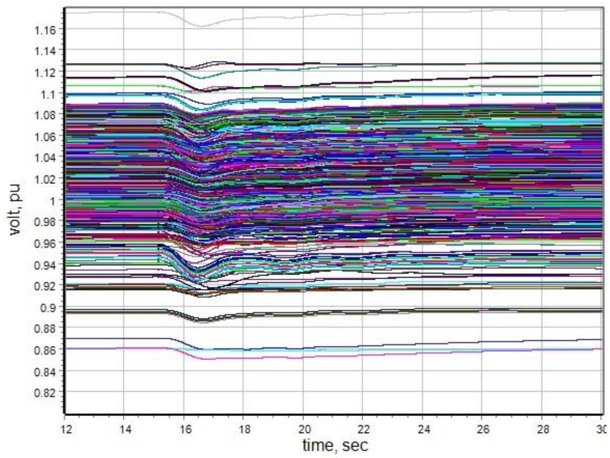
Figure 5. Voltage Support Due to the Contingency with 50% (Maximum) Renewables

Table 6. System Inertia with 50% Renewables

Panel A: 2028 Base Case	Panel B: 2030 GHG-Neutral Case
System Inertia = 7158.14	System Inertia = 7186.8

Panel A: 2028 Base Case | **Panel B: 2030 GHG-Neutral Case**

Figure 6. Number of Buses with Minimum and Maximum Limit Voltage Violations with 50% Renewables



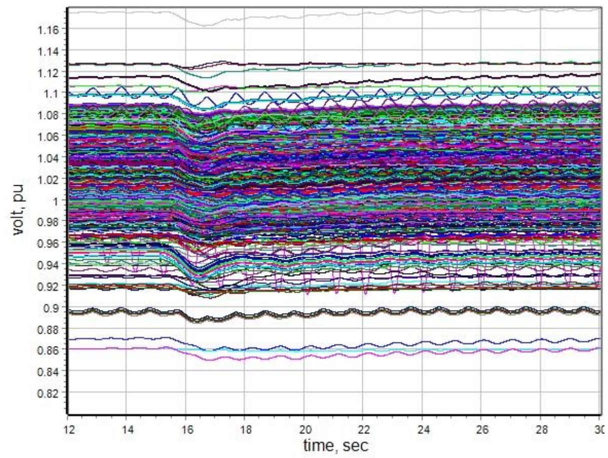


Figure 7. Voltage Support Due to Contingency with 3.9% Renewables

Table 7. System Inertia with 3.9% Renewables

Panel A: 2028 Base Case	Panel B: 2030 GHG-Neutral Case
System Inertia = 7158.14	System Inertia = 7186.8

Panel A: 2028 Base Case	Panel B: 2030 GHG-Neutral Case

Figure 8. Number of Buses with Min. and Max. Voltage Limit Violations with 3.9% Renewables

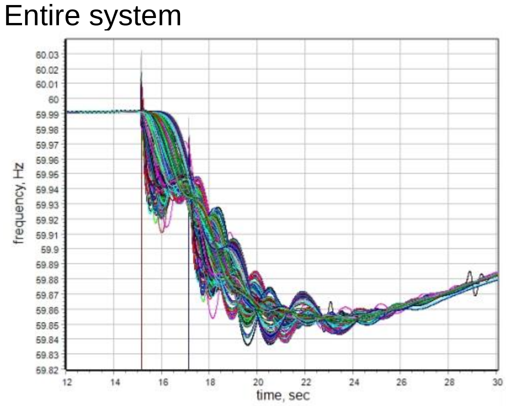
Contribution of Flexible Technologies to Grid Stability with Expanded Renewables

With new investments, 12 additional 13.8 kV buses are created and added to Rocky Ford, Centralia (230 kV), and Hanford (500 kV) buses through step-up transformers. Each of these buses is connected to four ANRs of 80 MW capacity each. Similarly, one 13.8 kV bus was created near the La Pine bus for adding 10 enhanced geothermal units each of 100 MW capacity through transformers (for a total of 1 GW enhanced geothermal capacity). One scenario is considered with maximum renewable generation in the case. Two system configuration files are considered with corresponding dynamic models, which are (A) the Base Case (Adjusted) without any additional ANR or enhanced geothermal units, or (B) the Expanded Renewables AC Power Flow with ANRs (12X80 MW) and enhanced geothermal units (10X100MW).

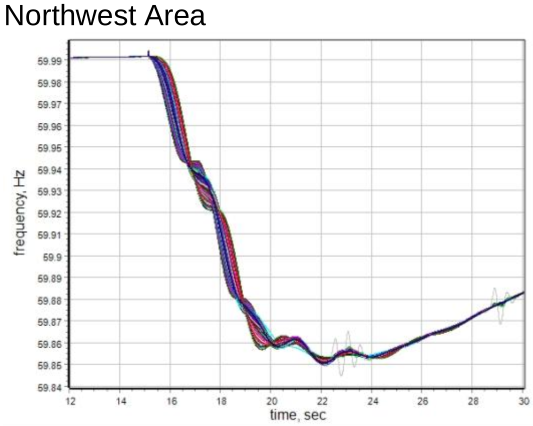
As shown in Figure 9, after adding 1,960 MW of generation from additional ANRs and enhanced geothermal units, the frequency response characteristics were improved. With the Expanded Renewables Case (Panel B), the frequency nadir was only up to 59.89 Hz compared to 59.835 Hz in case of the Base Case (Adjusted) (Panel A), both scenarios were evaluated for the entire system. Also, as shown in Table 8, as a result of adding new generation units, system inertia was improved from 7,485.59 MWsec to 7,586.17 MWsec. As shown in Figure 10, the voltage profile for both the Base Case (Adjusted) (Panel A) and Expanded Renewables Case (Panel B) remained similar; the modified system is stable and has a good voltage profile. From the histogram plots obtained on results of contingency simulation, as shown in Figure 11, there was no introduction of any new violations due to generation loss contingencies across transmission system.

Panel A: Base Case (Adjusted)

Entire system

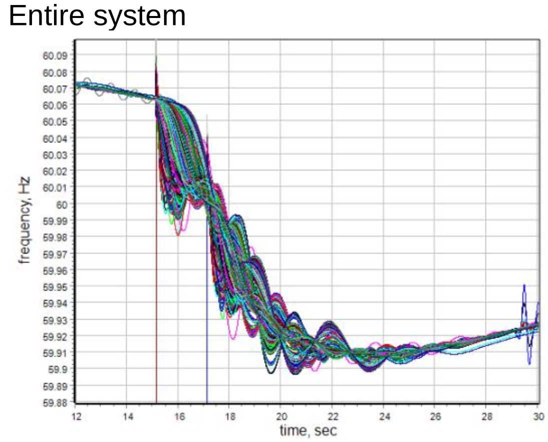


Northwest Area



Panel B: Expanded Renewables

Entire system



Northwest Area

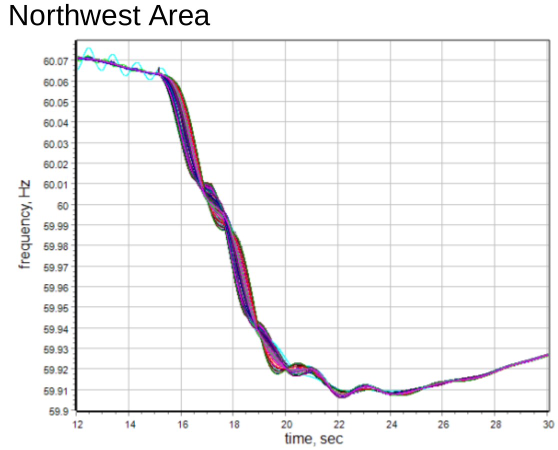
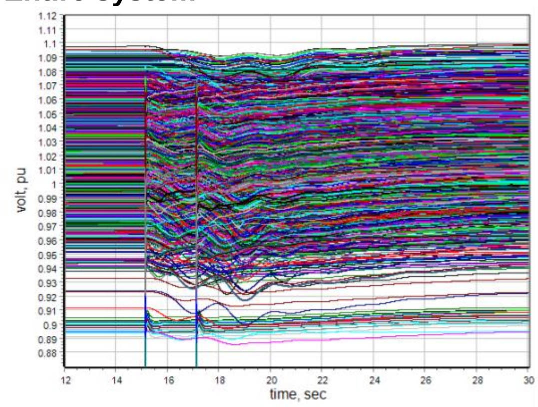


Figure 9. Frequency Response in the Expanded Renewables Case

Table 8. System Inertia in the Expanded Renewables Case

Panel A: Base Case (Adjusted)	Panel B: 2045 Expanded Renewables
System Inertia=7485.59	System Inertia=7586.17

Panel A: Base Case (Adjusted)	Panel B: 2045 Expanded Renewables
Entire system	Entire system



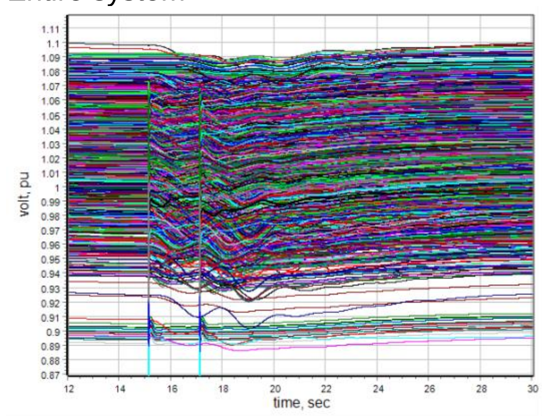


Figure 10. Voltage Support Due to Contingency in the Expanded Renewables Case

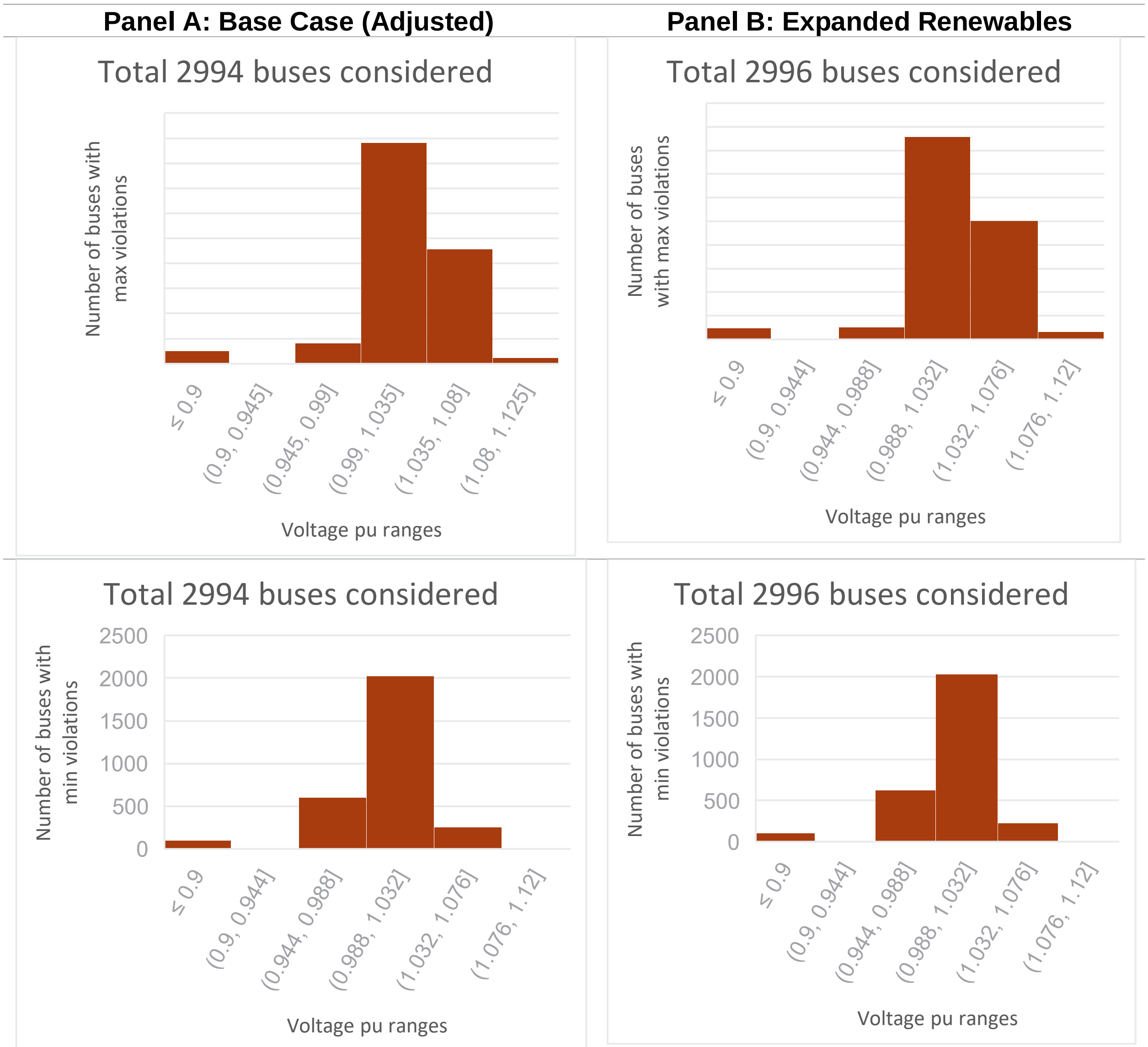
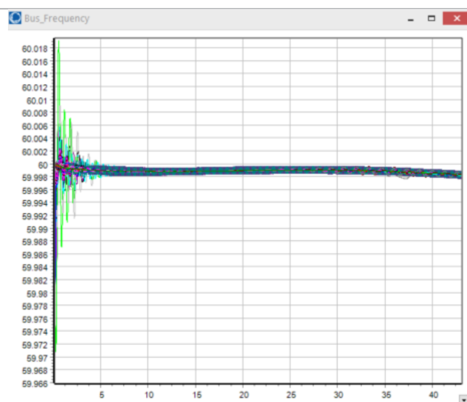
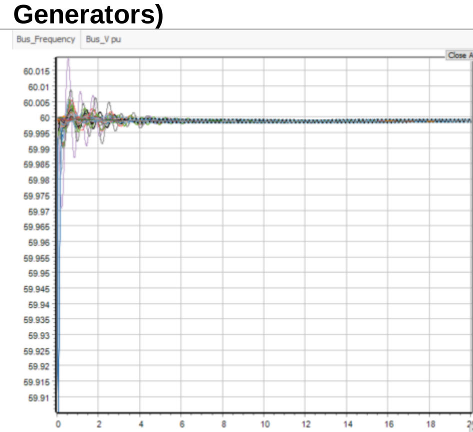
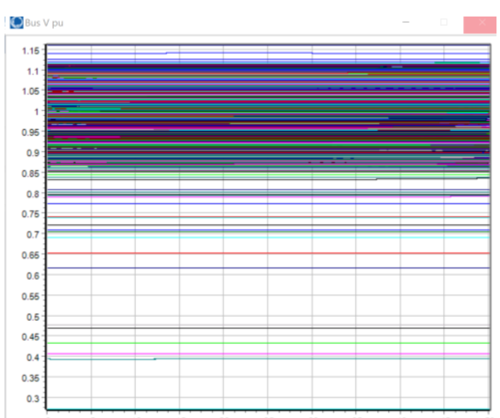
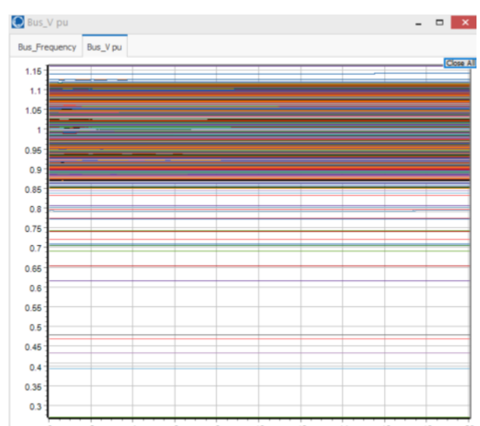


Figure 11. Number of Buses with Minimum and Maximum Violations in the Expanded Renewables Case

4.3.2.2 System Stability with the 2045 100% Clean Energy Case

For the 2045 100% Clean Energy Case, we used C-PAGE to generate the AC power flow case from the DC power flow dispatch from the 100% Clean Energy Case with optimal placement of wind, solar, storage, and ANRs as discussed in 3.2.2. Our objective with this analysis was to understand if the system remained stable under a high penetration of renewable resources. Our analysis was conducted with the detailed model of system components connected to the bus with the largest addition of wind generation capacity (1225 MW).

A total of nine wind turbine farms with 150 MW of generation each were added to the system. A comparison of the two cases before and after adding the nine generating farms was conducted for analyzing the stability of the system. Both ambient and transient simulations were carried out under normal and a high impact contingency condition (Palo Verde outage) respectively. The contingency was created with fault condition at 15 and 17 seconds, each followed by outage of 1,250 MW units. As can be seen from the Figure 12, the modified case led to a flat start under normal conditions in a simulation of the system for 50 seconds. The modified system was stable under normal operating conditions in both voltage and frequency. Under Palo Verde contingency conditions, the system also led to a stable operating point. Both frequency and voltage were stable over the 50 seconds simulation. Due to lack of reactive power adjustments, both the original and modified cases had some violations in frequency at certain 0.5kV generation units. Overall, there was no introduction of any new violations due to generation loss contingencies across transmission system due to additional generation units.

Under Scenarios	Base Case (No New Generators)	100% Clean Energy (Nine Wind Generators)
Normal Operating Condition		
		

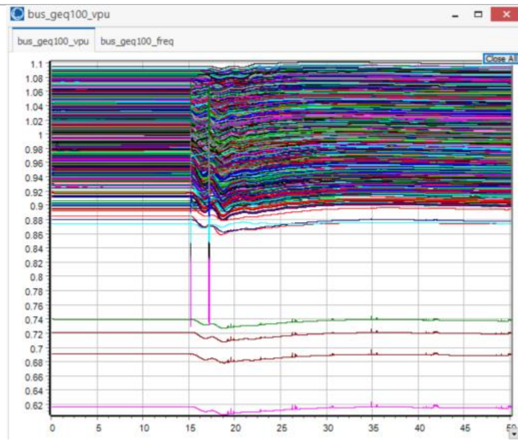
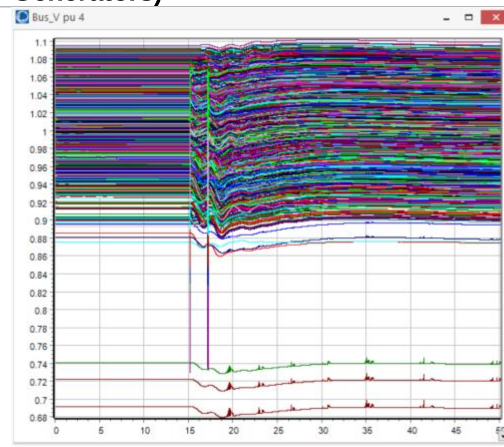
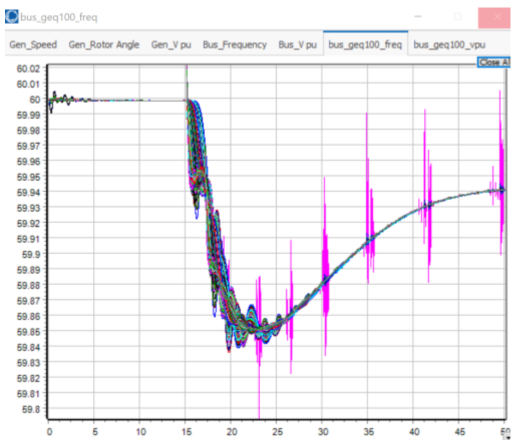
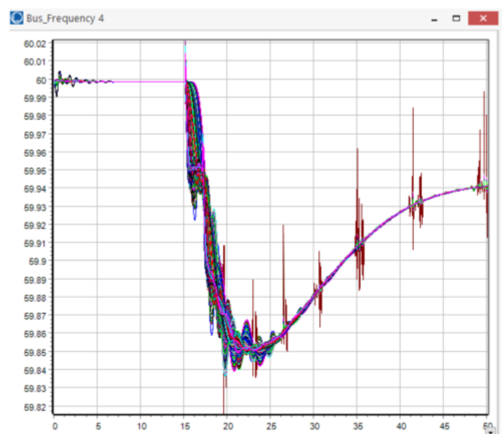
Under Scenarios	Base Case (No New Generators)	100% Clean Energy (Nine Wind Generators)
Palo Verde Contingency Scenario		
		

Figure 12. Transient stability analysis indicates a stable system with added renewables

4.4 Economic Feasibility

We present our economic feasibility results by relevant scenario for the Oregon and Washington region (because we assume the SHR EGS is located in Oregon in later scenarios) and provide the Base Case for comparison. Note that only Washington State clean-energy policies are incorporated in the PCM.

4.4.1 Base Case

In the Base Case, the generation mix in Oregon and Washington is primarily composed of hydro, combined cycle natural gas, onshore wind, and nuclear power production, which account for 95% of power production. Figure 13 displays the percentage of generation by technology compared to total generation (in MWh) for the annual PCM run. Note that this graph compares actual generation (in MWh) by technology, rather than installed capacity (MW) (Figure 13).

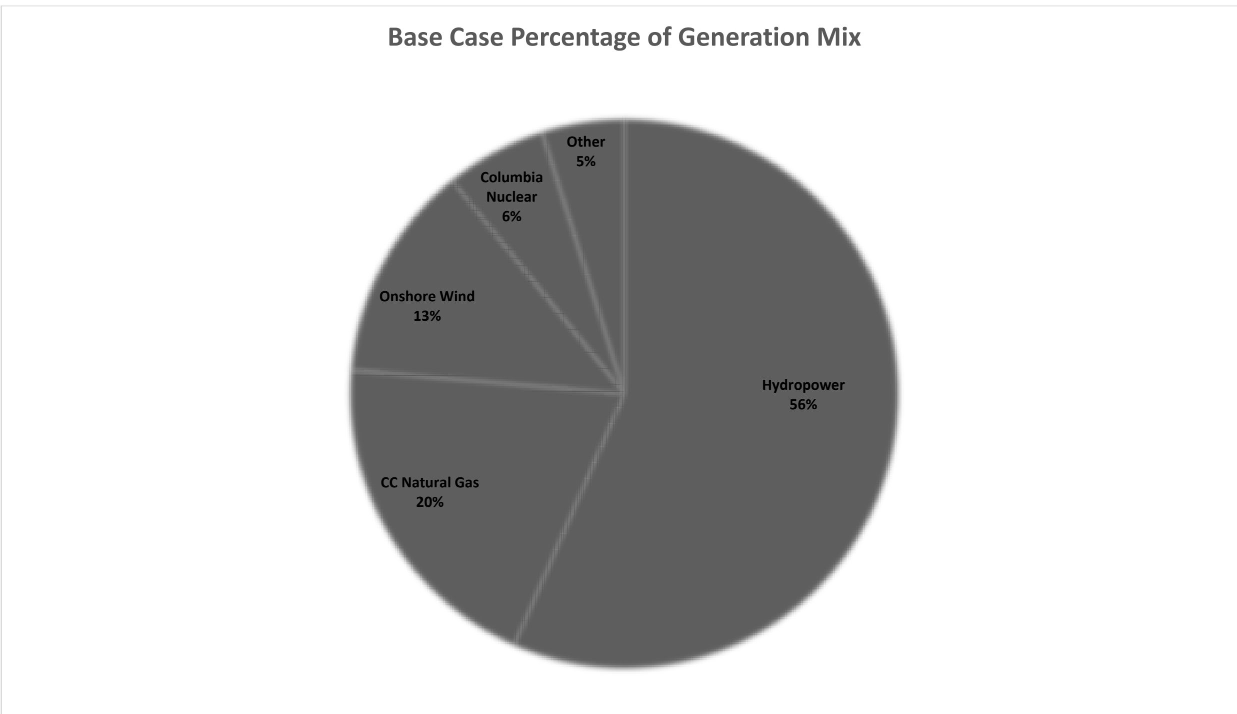


Figure 13.   Generation Mix in the Base Case (MWh %)

Table 9 provides results for the Base Case. The main power-producing technologies in Oregon and Washington earn revenues from the energy and ancillary service markets that cover their variable O&M as well as fuel costs (not shown), but, with the exception of power generated from Columbia Power Plant, do not provide sufficient revenue to allow generators to cover their total annualized fixed costs from capital investment.[1] The unsubsidized profit column subtracts the LCOE from the revenue earned in the energy and ancillary service markets. The subsidized profit column subtracts the LCOE including tax credits (if applicable) from the revenue earned in the energy and ancillary service markets. Across all main technologies, both subsidized and unsubsidized profits show that most generators will require some form of capacity payment to

[1] Other less utilized technologies including natural gas combustion turbine, pumped storage hydro, and waste heat technologies do not earn sufficient revenue to cover O&M and fuel costs.

make these generators whole and allow their continued participation in the market. However, we note that the LCOE estimates provided are for new generators entering the market; existing generators with lower capital costs may feasibly stay in the market with short-term energy and ancillary service revenues alone.

Table 9. Results of the PCM Model for the Base Case

Technology	Revenue ($/MWh)	Levelized Cost of Electricity ($/MWh)[1]	Levelized Cost of Electricity Including Tax Credit ($/MWh)	Unsubsidized Profit (Loss) ($)	Subsidized Profit (Loss) ($)	Percentage of Generation Mix
Hydropower	29	73	57	(43)	(28)	57%
Combined Cycle Natural Gas	38	43	43	(5)	(5)	20%
Onshore Wind	24	51	51	(27)	(7)	13%
Nuclear (Columbia Power Plant)	43	42	28	1	15	6%

$/MWh = Dollars per Megawatt Hour

4.4.2 2030 GHG-Neutral Case

In the 2030 GHG-Neutral Case, the generation mix in Oregon and Washington is primarily composed of hydro, combined cycle natural gas, onshore wind, and nuclear power production, which account for nearly 96% of power production. Compared to the Base Case, more hydro, wind, and nuclear power are dispatched, and significantly less natural gas power is dispatched. Geothermal from SHR EGSs is 1% of the generation mix. Nuclear power dispatch includes both power from the existing Columbia Power Plant (6%) and the ANR in Eastern Washington (2%) for total nuclear power dispatch of 8% (Figure 14).

[1] LCOE estimates in this table are from the U.S. EIA Annual Energy Outlook 2023 for hydropower, combined cycle natural gas, and onshore wind. Columbia Power Plant estimates are based on PNNL calculations. We assume the Zero-Emission Nuclear Power Production Credit applies to existing nuclear generation at 1.5 cents/kWh (1992 dollars, inflation adjusted). The 1.5 cents/kWh assumes prevailing wage and apprenticeship requirements are met (Inflation Reduction Act of 2022). We assume the credit does not phase out, i.e., U.S. GHG emissions from electricity are greater than 25% of 2022 emissions.

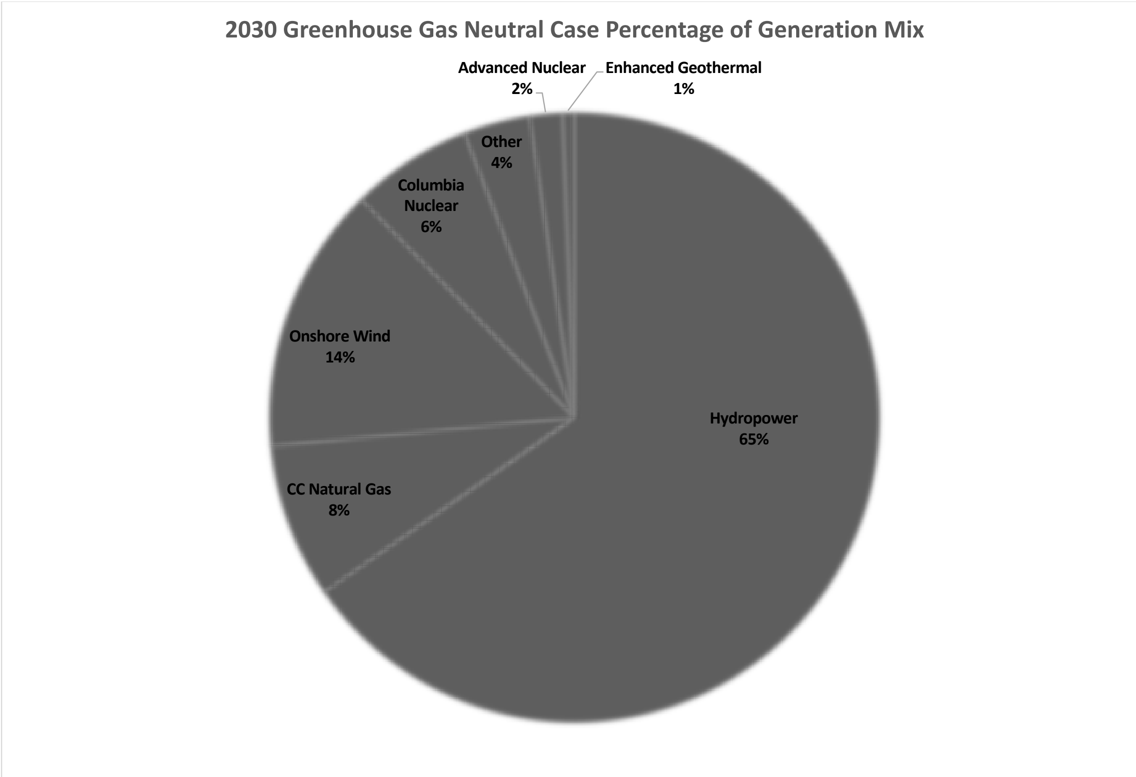


Figure 14. 2030 GHG-Neutral Case Generation Mix (MWh %)

In Table 10, in the 2030 GHG-Neutral Case, revenues are again sufficient to cover variable O&M and fuel costs across most technologies (except pumped storage hydropower), but they are insufficient to cover fixed costs from capital investment for most technologies that supply the majority of power to Washington and Oregon (although revenues are sufficient for combined cycle natural gas and traditional nuclear plants); as such, capacity payments of some form will likely be necessary for some generators to cover their fixed costs. Production tax credits available from the Inflation Reduction Act of 2022 are sufficient to make most technologies whole. Compared to the Base Case, revenues increase for hydropower, onshore wind, conventional nuclear technologies, and natural gas technologies (note that all natural gas combined cycle imports and generation to serve Washington load pay a penalty $0.060/kWh in this scenario). Revenues (in $/MWh) for ANRs are lower per unit of generation than revenues for the Columbia Power Plant. Note that the LCOE for nuclear and geothermal are those calculated by PNNL to determine the capacity payment necessary to make whole the new technologies in this scenario. We estimate a capacity payment of $10 in the unsubsidized case will be necessary to ensure revenue sufficiency for SHR EGSs. A capacity payment of $12 (unsubsidized) will be necessary for ANRs.

Table 10. Results for the 2030 GHG-Neutral Case

Technology	Revenue ($/MWh)	Levelized Cost of Electricity ($/MWh)	Levelized Cost of Electricity Including Tax Credit ($/MWh)	Unsubsidized Profit (Loss) ($)	Subsidized Profit (Loss) ($)	Percentage of Generation Mix
Hydropower	43	73	57	(30)	(14)	65%
Combined Cycle Natural Gas[1]	56	43	43	13	13	8%
Onshore Wind	33	51	31	(18)	2	14%
Nuclear (Columbia Power Plant)	53	42	28	11	25	6%
Advanced Nuclear (excluding Columbia Power Plant)[a]	47	59	48	(12)	0	2%
Enhanced Geothermal	46	56	45	(10)	1	1%

$/MWh = Dollars per Megawatt Hour.
[a] Numbers for profit (loss) do not sum to revenue minus LCOE in table due to rounding error, subsidized loss is (0.15).

4.4.3 2045 100% Clean Energy Case

In the 2045 100% Clean Energy Case, when 100% clean-energy resources serve load in Washington State, the generation mix serving Washington load is primarily composed of hydro, onshore wind, and advanced nuclear power production, which account for more than 87% of power production. Compared to the 2030 GHG-Neutral Case, slightly less hydro and traditional nuclear power is dispatched. Wind generation is 14% of the generation mix and solar PV increases to 4%. Geothermal from SHR EGSs increases to 6% of the generation mix and ANR generation to 23% (Figure 15).

[1] Natural gas generators include those from Washington (with the $60/MWh tax) and Oregon (without the $60/MWh tax).

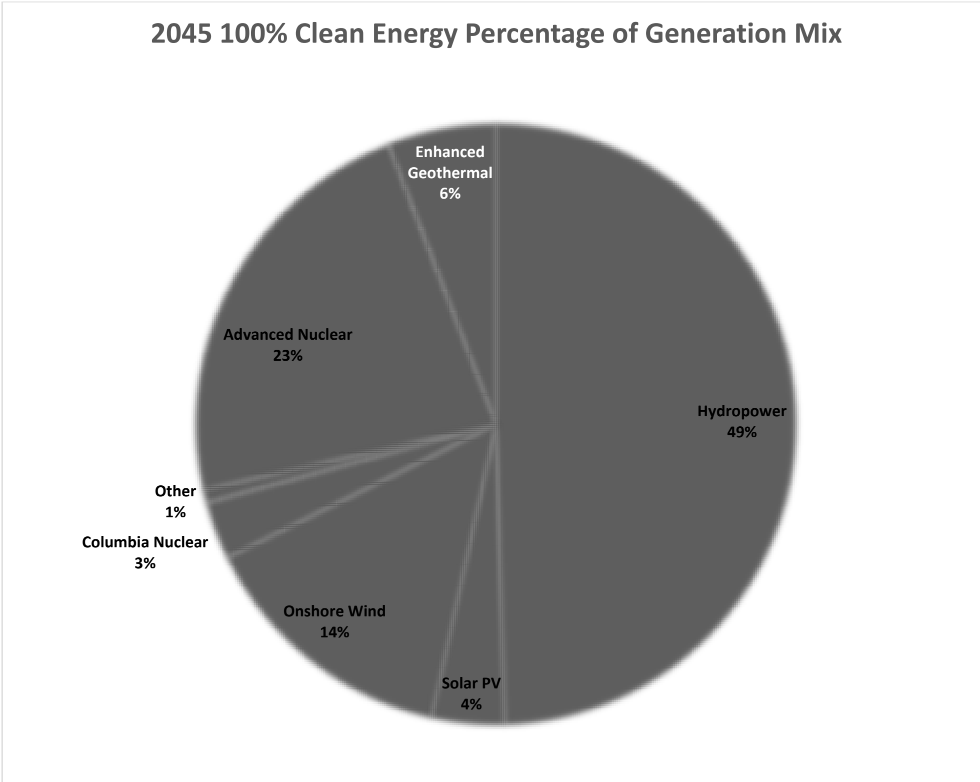


Figure 15. 2045 Proposed Clean Energy Generation Mix (MWh %)

In Table 11, in the 2045 100% Clean Energy Case, revenues are again sufficient to cover variable O&M and fuel costs for most technologies (excluding advanced nuclear [not shown]) but are insufficient to cover fixed costs for all unsubsidized technologies and nearly all subsidized technologies. Compared to the 2030 GHG-Neutral Case, hydropower and conventional nuclear dispatch decrease and revenues per unit of generation also decrease substantially. Advanced nuclear dispatch increases significantly but revenues per unit of advanced nuclear power plant generation decrease. Geothermal dispatch also increases but revenues per unit of generation decrease substantially. We estimate a capacity payment of $38 in the unsubsidized case or a capacity payment of $27 in the subsidized case will be necessary to ensure revenue sufficiency for SHR EGSs. A capacity payment of $38 (unsubsidized) or $26 (subsidized) will be necessary for ANRs.

Table 11. Results from the 2045 100% Clean Energy Case

Technology	Revenue ($/MWh)	Levelized Cost of Electricity ($/MWh)	Levelized Cost of Electricity Including Tax Credit ($/MWh)	Unsubsidized Profit (Loss) ($)	Subsidized Profit (Loss) ($)	Percentage of Generation Mix
Hydropower[a]	15	73	57	(57)	(42)	49%
Solar PV	18	41	23	(23)	(5)	4%
Onshore Wind	18	51	31	(33)	(13)	14%
Nuclear (Columbia Power Plant)	40	42	28	(2)	12	3%
Advanced Nuclear (excluding Columbia Power Plant)[a]	22	59	48	(38)	(26)	23%
Enhanced Geothermal	18	56	45	(38)	(27)	6%

$/MWh = Dollars per Megawatt Hour.
[a] Numbers for unsubsidized profit loss do not sum to revenue minus LCOE in table due to rounding error.

5.0 Discussion

We developed an integrated economic and engineering modeling approach in which we estimated the costs of two new technologies—ANRs and SHR EGSs—and added those flexible resources to power system scenarios that reflected the Washington State CETA compliance requirements and milestones to achieve 100% clean energy by 2045.

By obtaining proprietary cost and operational data from our industry partners, X-energy and AltaRock Energy, we were able to develop realistic cost estimates for ANRs and SHR EGSs and assess their potential economic feasibility from the value of services they would likely earn in the future resource mix.

We assessed the cost and stability of the future resource mix and found that with the 2030 GHG-neutral policy requirements and relative to the Base Case, generation costs and CO_2 emissions were both reduced (and emissions in Washington were particularly reduced), given reduced fossil-fuel use and replacement of fossil-fuel generation by nuclear and geothermal generation due to enforcement of CETA policies. From a system stability perspective, with the 2030 GHG-Neutral Case, the system response remained stable, even after applying a system contingency under both minimum and maximum renewables penetration levels. System inertia was also improved, and no new voltage limit violations were introduced with the addition of new, flexible resources.

With the 2045 100% Clean Energy Case, CO_2 emissions were significantly reduced, and generation costs were also reduced, due to significant replacement of fossil-fuel generation with zero cost wind resources, as well as nuclear and geothermal resources. The addition of more flexible resources improved frequency response characteristics and system inertia. The voltage profile remained stable after applying a system contingency under maximum renewables penetrations, and there were no new voltage limit violations. The modified system with generating units led to a stable case under Palo Verde contingency simulation.

LMPs, on the other hand, increased for the 2030 GHG-Neutral Case but decreased for the 2045 100% Clean Energy Case. Increases in LMPs in the 2030 GHG-Neutral Case may be due to the increased cost and reduced availability of natural gas generation, creating congestion and price spikes. Added wind generation in 2045 could also contribute to congestion. The reduced LMPs in the 2045 100% Clean Energy Case may be due to added nuclear generation reducing congestion and suppressing some of this observed price volatility.

With respect to the economic feasibility of the two new technologies, given the value of services earned in the future resource mix, we found that with an estimated LCOE of $45 to $56, depending on availability of incentives, SHR EGSs would need a capacity payment of up to $10 under the policy requirements and potential generation mix in the 2030 GHG-Neutral Case, and $27 to $38 under the policy requirements and potential generation mix in the 2045 100% Clean Energy Case. SHR EGSs had increased dispatch but decreased revenues from the 2030 to 2045 scenarios, resulting in the need for an increased capacity payment.

We found that with an estimated LCOE of $48 to $59, depending on the availability of incentives, ANRs (estimated as a four-pack of 80 MW reactors) would need a capacity payment of up to $12 under the policy requirements and potential generation mix in the 2030 GHG-Neutral Case, and a capacity payment of $26 to $38 in the 2045 100% Clean Energy Case. As ANR dispatch increased but revenues decreased from the 2030 GHG-Neutral Case to the 2045

100% Clean Energy Case, the magnitude of the needed capacity payment increased due to declining revenues per unit of generation (although generation increased substantially).

Our modeling approach is based on several important assumptions and limitations, which may affect our results.

- First, we use the 2028 WECC planning model as our base case and build from it for our future resource mix scenarios. Our future resource mix results could be biased if the 2028 WECC planning model differs substantially from the actual future resource mix (across WECC) in 2030. In future research, we recommend using the WECC 2030 model, which has more installed renewable capacity, as the base case.
- Second, in future research we recommend exploring transmission upgrades (increased capacity and/or additional network lines) to support the integration of 100% renewable power to meet system demand at all hours.
- Third, we recommend the development of a bid-based model to analyze potential price and revenue impacts to address inherent limitations of the development of prices (based on production costs and system constraints) in the PCM. Further investigation into market dispatch systems that do not rely on unit commitment models is also warranted.

Although there are important limitations to our research design, our research contributes to our understanding of the economic feasibility of the future resource mix in Washington State as well as the role and economic feasibility of two future technologies that could provide valuable flexibility services to the future resource mix. More detailed analyses could provide Washington State and electricity participants with a complete understanding of the potential challenges and solutions to achieving clean-energy policy requirements, as well as consider additional new technologies (green hydrogen). More detailed analyses could also provide insight into the social and distributional impacts of the future resource mix in Washington State, including the equitable distribution of energy and non-energy benefits of the transition to clean energy and their impacts on vulnerable populations and disadvantaged communities. Finally, more detailed analyses could consider future policy implications for all states in the WECC region, and how they affect Washington State.

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Appendix A – Nuclear Cost Data Questionnaire

Assume Nth of a Kind Plant Deployment

Please provide ranges for applicable items with expected, low and high.

1.0 Plant Data	**Expected**	**Low**	**High**
Plant name -			
Gross of Plant Power (MWth/MWe)-	_______	_______	_______
Net Plant Efficiency -	_______	_______	_______
Rolling Plant Capacity Factor Over Several Years–Planned outages.	_______	_______	_______
Fuel Form (UO2, metallic, aqueous, etc.) & Enrichment (LEU/HALEU/TRISO/other) –			
Wet cooled vs Dry Cooled TRISO pebble bed	_______	_______	_______
Ultimate Heat Sink (water or air cooling) -	_______	_______	_______
Number of Individual Modules per Plant (if applicable) –			
Site Size (Acres) – Potentially renting	_______	_______	_______
Emergency Planning Zone-Plume exposure pathway (Miles)	_______	_______	_______
Probability of attaining the mileage (Probability)	_______	_______	_______
Emergency Planning Zone-Ingestion pathway (Miles)	_______	_______	_______
Probability of attaining the mileage (Probability)	_______	_______	_______

2.0 Economics Data

Interest rate – site acquisition, licensing and civil works phase	_______	_______	_______
Interest rate – construction phase	_______	_______	_______
Interest rate – operating phase	_______	_______	_______
Interest rate – decommissioning sinking fund	_______	_______	_______
Interest rate – other sinking funds?	_______	_______	_______
Ownership – discount rate	_______	_______	_______
Time period – licensing, acquisition, and civil works phase	_______	_______	_______
• Expected Cost	_______	_______	_______
Time period – construction phase	_______	_______	_______
• Construction costs and spend curve	_______	_______	_______
• Cost to tie into the electric grid including new transmission lines	_______	_______	_______

- Safety amount of concrete used to construct plant ______ ______ ______
- Non-safety amount of concrete used to construct plant ______ ______ ______
- Safety amount of steel used to construct plant ______ ______ ______
- Non-safety amount of steel used to construct plant ______ ______ ______
- Total Cost ______ ______ ______
- Class of cost estimate (Class 1-Class 5?) ______ ______ ______
- Cost savings associated with existing infrastructure (site 1) ______ ______ ______

Time period – start up months ______ ______ ______

Operating Phase – number of years ______ ______ ______

- Estimated annual maintenance costs ______ ______ ______
- Estimate of annual fuel costs (what are underlying assumptions for SWU, O3O8, etc. to help normalize across multiple vendors) ______ ______ ______
- Estimate of annual costs to store fuel at site ______ ______ ______

Number of Plant Personnel & Estimated Annual Salaries ______ ______ ______

- Engineering & Maintenance Support ______ ______ ______
  - Average annual salaries ______ ______ ______
- Operations ______ ______ ______
  - Average annual salaries ______ ______ ______
- Refueling Support ______ ______ ______
  - Average annual salaries ______ ______ ______
- Security cost estimate ______ ______ ______
- Overhead Personnel ______ ______ ______
  - Average annual salaries ______ ______ ______

Deactivation & Decommissioning Phase – Number of Years ______ ______ ______

- Estimated Cost ______ ______ ______
- Spent fuel cost ______ ______ ______

3.0 Additional Information for Consideration

Is there a phased deployment of a modular SMR, or multiple single SMR units at one site? If it is a phased deployment of modules, what is the time period to achieve first revenue and is this shorter than the entire plant construction phase?

Is the inertia of an SMR turbine the same as a GEN III steam turbine?

Summarize Attributes for Flexible Operations (e.g., load following, frequency control, reactive power, etc.)

Summarize Approach to Flexible Operations: For example, dumping steam to condenser or reactor power maneuvering and response time to significant load changes (seasonal, weekly, daily, 5-minutes, etc.).

Summarize Non-baseload Applications: shifting power to energy storage, hydrogen production, pumped hydro, or providing process heat for industrial uses during periods of low grid demand. Include information on process heat temperature for these applications.

Electrical grid "cold start" capability?

Capable of micro-grid / Island mode operations?

Fuel reload frequency and planned outage durations?

What is additional cost per MWe to add new capacity to support new grid demand?

What is ratio of installed MWe vs regional daily peak grid demand?

What is ratio of installed MWe vs regional daily average grid demand?

Appendix B – Differences in the 2028 WECC ADS and 2030 WECC ADS Planning Models

Table B.1 provides the differences in the 2028 WECC ADS planning model with respect to the 2030 WECC ADS planning model (positive means generator addition in 2030). The 2028 WECC ADS doesn't include any additions that were added to meet the CETA carbon neutral scenario associated with models for this project.

Table B.1. Difference in generator inventory between the 2030 WECC planning model and the 2028 WECC planning model (2030 minus 2028)

Gen Type	Alberta	British Columbia	Basin	California + Baja MX	Desert Southwest	Northwest	Rocky Mountain	Total
Hydro	23	-1,757	85	-3,952	-200	-108	-518	-12,857
Steam[a]	-550	-10	-1,478	-206	41	8	-997	-6,383
Combined Cycle	66	11	118	361	-4,809	31	-381	-9,206
Combustion Turbine	120	3	494	145	-1,568	-81	-590	-2,954
Internal Combustion	39	0	77	47	72	116	113	927
Energy Storage	0	0	586	3,480	603	848	-13	11,008
Biomass	-53	-18	5	-287	0	9	0	-687
DG/DR/EE	0	0	770	19,998	2,777	133	1,209	49,771
Geothermal	0	0	-1	-61	250	-10	0	354
Solar	-153	23	2,000	1,107	7,933	1,220	1,177	26,614
Wind	-1,646	-52	3,156	-405	1,001	110	504	5,335
Total	-2,154	-1,801	5,810	20,228	6,099	2,276	505	61,923

DG = Distributed Generation, DR = Demand Response, EE = Energy Efficiency

[a] The steam category includes nuclear power. The differential of nuclear power between the WECC 2030 and the WECC 2028 planning study is zero for Alberta, British Columbia, Basin, California + Baja, and Rocky Mountain. The differential of nuclear for Desert Southwest is 66 MW, and for Northwest is 15 MW.

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