Western Flexibility Assessment

Investigating the West's Changing Resource Mix and Implications for System Flexibility

December 10, 2019

Final Report

Prepared by Energy Strategies for submission under Agreement with the Western Interstate Energy Board

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About the Study

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Disclaimers

This publication was prepared as the result of independent study work sponsored by the parties listed above. It does not necessarily represent the views of the sponsors or their employees.

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EXECUTIVE SUMMARY

Study Brief

The purpose of the Western Flexibility Assessment is to investigate the flexibility of a future grid in which renewable resources are deployed at levels consistent with enacted and foreseeable public policy requirements of Western states. The study provides government and industry decision makers insights on potential options to improve the flexibility of the grid. The study considers the 2025-2035 time horizon and evaluates system flexibility for this future using modeling tools designed to simulate grid operations, transmission capabilities, and system reliability. Key takeaways from the study include the following:

- A balanced set of solutions are likely needed to increase system flexibility to levels sufficient to achieve enacted or anticipated state policy goals. By aggregating individual state goals, this study estimates 2026 and 2035 Western clean energy penetration targets of 33% and 64%, respectively.

- Strategies considered in this study that proved to be effective at increasing levels of system flexibility include enhanced market coordination, transmission additions, diverse resource selection, new energy storage, and load management. A scenario that includes these solutions, together, achieved a 2035 clean energy penetration of 69%, exceeding the estimated West-wide policy target.

- The need to implement flexibility enabling strategies across the West increases over time. In the near-term, flexibility challenges exist and the system will benefit, operationally, from certain investments and enhanced market coordination. However, for this near-term timeframe the West is reasonably primed – in terms of system flexibility – to achieve near-term policy targets. In the long-term, results indicate that material flexibility challenges exist in the West and, absent implementation of some or all of the flexibility solutions listed above (or solutions providing similar flexibility effects), the West may lack sufficient grid flexibility to achieve state energy goals.

- Interregional power transfers are likely to increase in the coming years and such economic transfers are one of the most effective tools to for increasing system flexibility. In the near-term, modeling indicates that regions will rely heavily on the ability to export excess generation to their neighbors. Coordinated power markets help make these transactions more efficient. In the long-term, the same neighbors often find themselves with excess energy of their own (because of increasing renewable deployments), which tends to exacerbate flexibility challenges across the system as there are fewer willing buyers for excess power. This inability to export power because of broad and more frequent oversupply conditions means that avoiding these conditions in the first place (e.g., diverse resource mixes) is critical, but load-shifting or storage solutions will also have a role in the West. Electrification, which is not considered in detail in this study, will also have a mitigating effect so long as it is implemented properly.

- While the study did not consider the effectiveness of all potential flexibility solutions, it does indicate that no technological breakthroughs are needed in order to achieve regional flexibility levels appropriate for resource mixes commensurate with state policy goals. Existing technologies and strategies, many of which are time tested, such as transmission expansion, pumped storage, market coordination, flexible gas units, load management and resource mix diversity, are all effective and technologically available flexibility solutions.

- New or maturing technologies, such as off-shore wind or new storage technologies, will only add to the supply of flexibility solutions, which, combined with existing solutions listed above, suggests that the question of achieving levels of system flexibility required for future system operations is not a question of “if” but rather “how”. The complexity involved in answering the “how” question is demonstrated by the broad range of flexibility solutions that proved to be effective in this analysis as each solution has varying costs and benefits.

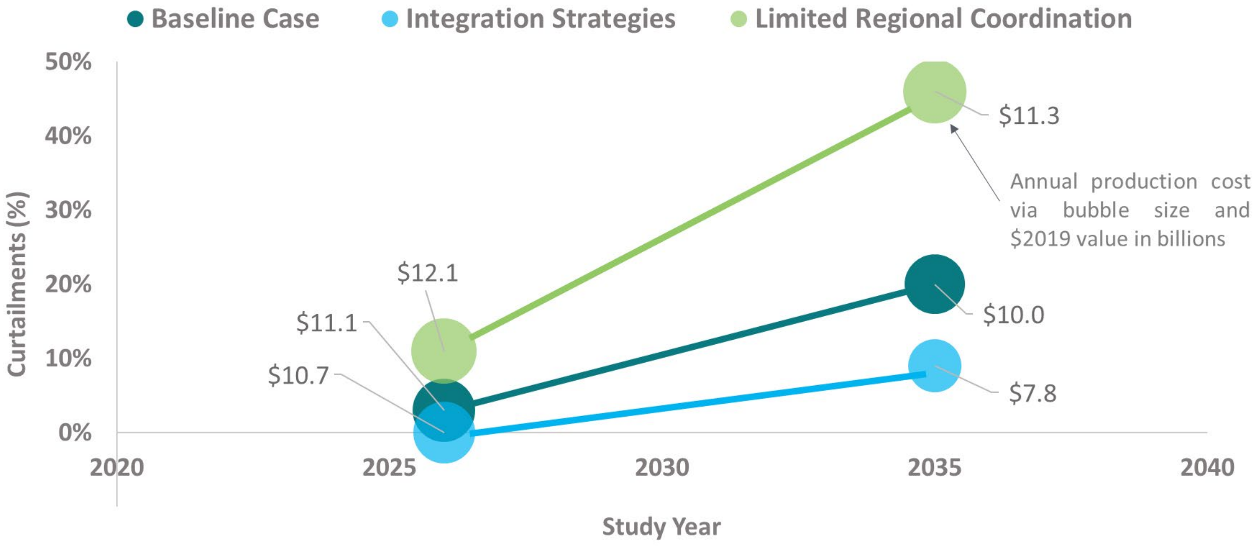
- Coordinated wholesale markets are effective at increasing system flexibility across the West. Near-term policy targets are achievable even if coordinated wholesale markets in the West do not materialize. However, the West will operate with a less flexible system with higher operational costs and emissions should coordinated markets not materialize in the next several years. In the long-term, results indicate that it will be very difficult, or at least extremely costly, to achieve Western policy targets without broad coordination of wholesale markets. By the 2030’s, not achieving broad market coordination causes significant increases in operational costs and emissions, withholding much needed flexibility from the Western grid.

- In addition to the operational challenges associated with achieving policy goals, the study estimates that the West must add roughly 9 GW of renewable energy, per year, starting in 2026, in order to provide energy sufficient to meet state policy goals through 2035. These investments in renewable energy represent only a subset of the potential infrastructure needs as this study also forecasts additional gas-fired resources, new transmission, significant storage build-outs, and demand engagement programs. The modeling performed for this study is not precise enough to identify specific state or utility needs or optimal resource choices for the entire region, but it does suggest that significant, but achievable, work must be undertaken across the Western region in order to realize a resource mix, transmission grid, and market paradigm that suits state policy targets.

- The study included a detailed evaluation of the Western transmission system. With a few isolated exceptions, most of which were caused by new generation siting assumptions, results indicate relatively few major transmission constraints on the system exist in the mid-2020s. As the resource portfolio evolves into the 2030s, the need for transmission becomes more obvious and resources face transmission constraints. There was significant congestion on the system during this timeframe, even under a future in which the system operators use the system up to its reliability limit and manage congestion through security-constrained economic dispatch.

- Resource adequacy is an important component of flexibility analysis. A system that is deficient in capacity will have exaggerated flexibility needs – the two are intertwined. The portfolios considered in this study were constructed to achieve regional adequacy targets, and in the case of the Northwest region, additional detailed analysis was performed to ensure the selected portfolio contained sufficient capacity. That modeling indicates that the Northwest region has a near-term capacity challenge, but that the deficit is one that can be addressed with existing technologies and resource options. The nature of the capacity challenge in the Northwest varies widely depending on assumptions regarding load forecasts and assumed resource build-outs. Analysis indicates that the capacity deficit varies between 1,100 MW by 2030 to more than 4,000 MW no later than the mid-2020s (or sooner, as no earlier years were studied), depending on load and resource-build assumptions. Results also indicate that gas, Montana wind, long-duration pumped storage, and increased access to Southwest market purchases, are all viable capacity solutions for the Northwest.

Figure 1: Summary of Key Flexibility Results by Study Case



Some of the study's most important metrics are presented above in **Figure 1**. The figure shows three study cases and Western renewable energy curtailments (as a percentage of total renewable energy), for the 2026 and 2035 study years. The size of the circles represents the Western system production cost for the given study case (in billions of dollars per year). As described in detail within this report, the study uses curtailments – undelivered renewable energy – as an indicator of system inflexibility. The Baseline Case is the study's business-as-usual scenario and it has modest curtailments in 2026, but significant curtailments by 2035, indicating an increasing need for system flexibility. The Integration Strategies scenario, which adds transmission, storage, resource diversity, and load management to the Baseline Case, shows how effective these strategies are at increasing system flexibility. Finally, the Limited Regional Coordination scenario *removes* day-ahead market coordination imbedded into the Baseline Case, which has the effect of decreasing flexibility and thus, increasing curtailments in both 2026 and 2035 (relative to the Baseline Case). This indicates the system flexibility benefits of market coordination. These results, among many others, helped to form the foundation for the study brief described above.

Study Background

The grid simulations used to perform this study produce metrics commonly used to evaluate system flexibility, including information about future resource mixes, generator curtailments, net load "ramping" requirements, operational costs, and carbon dioxide (CO_2) emissions. To confirm that the operational analysis included sufficient capacity resources in the Northwest, the study also considered regional adequacy for the Pacific Northwest under several resource and load futures. In addition to these operational and adequacy analyses, the study, at a high-level, also took into account bulk transmission flows, congestion, and system reliability under varying load and dispatch conditions.

The study work was centered around a Baseline Case future scenario, which was designed as an "expected future" that was consistent with the policy direction of the Western United States (U.S.). The study also considered two alternative future scenarios stemming off the Baseline Case, accounting for futures with increased and decreased system flexibility.

The study used four models to simulate system performance:

- **GridView™:** a security-constrained, unit commitment and dispatch model that represents the details of the transmission grid and hourly operational granularity;
- **AURORA™:** a zonal, capacity expansion model that samples operational weeks and considers system needs for the entire study horizon;
- **PowerWorld™:** a commercial power flow software used to analyze grid reliability during "snapshot" conditions; and
- **GENESYS:** Northwest Power & Conservation Council's Generation Evaluation System Model which was specially designed to investigate Pacific Northwest capacity issues and includes advanced modeling of the Northwest hydro system.

The models were used in a coordinated and sequential fashion to:

(1) build out policy-compliant and resource adequate generation portfolios for the Western system during the 2026-2035 study period;
(2) investigate the timing and nature of resulting capacity issues in the Northwest;
(3) evaluate hour-to-hour operational implications of the portfolios; and finally

(4) investigate the transmission congestion and reliability implications of the portfolios under certain system conditions, including those with high levels of renewable generation.

The study is one of the first efforts to model Western resource portfolios in line with very recent energy policies, including those recently passed in Washington, New Mexico, Colorado, Nevada, and California. In addition to these mandated policies, the study also assumed that Arizona and Idaho establish ambitious clean energy targets. While Arizona and Idaho do not have major incremental energy policies, procurement trends and voluntary targets by utilities prompted us to assume incremental clean energy requirements for this study.

This study effort is unique because it:

1) Is the first to simultaneously incorporate the significant recent energy policies and voluntary commitments in the Western U.S.;
2) Is wide-ranging, investigating flexibility challenges from both an operational, adequacy, and transmission reliability standpoint;
3) Includes a granular representation of the transmission system and captures interregional and transmission flow effects resulting from simultaneous achievement of assumed state energy goals;
4) Considers both institutional and physical strategies that might impact system flexibility.

Key Assumptions and Scenarios

The Baseline Case was used to represent an expected future. The study made the following assumptions to form the Baseline Case:

- **Renewable resources are deployed to meet the assumed state-level clean energy policy requirements;**
- **Regionalization of energy markets occur and there is a market platform that allows for optimized day-ahead and real-time trading between all Western Balancing Areas, free of transmission service charges;**
- **Near-term resources identified in integrated resource portfolios (IRPs) are constructed;**
- **Only transmission projects with a direct path to cost recovery are built;**
- **Load growth occurs consistent with recent forecasts;**
- **Resource costs change over time consistent with recent forecasts;**
- **8.3 million new electric vehicles (EVs) are deployed by 2035 (3.7 GWa of added load).**

The assumed policy requirements referenced in the first bullet are outlined below in **Table 1**. Incremental assumed state policy requirements are highlighted.

Table 1. Assumed RPS/Clean Energy Targets by State

	Year	California	Northwest						Intermountain		Rockies		Southwest	
		CA	OR		WA		ID	MT	NV	UT	CO	WY	AZ	NM
	2020	33%	20%		15%		4%	15%	22%	0%	30%	0%	10%	20%
	2021	33%	20%		15%		8%	15%	22%	0%	30%	0%	11%	20%
	2022	33%	20%		15%		12%	15%	26%	0%	30%	0%	12%	20%
	2023	33%	20%		20%		16%	15%	26%	0%	32%	0%	13%	20%
	2024	44%	20%		25%		20%	15%	34%	0%	36%	0%	14%	20%
	2025	44%	27%		30%		24%	15%	34%	0%	40%	0%	15%	25%
Study Period	2026	44%	27%	Cap and Invest	35%	Carbon Cap and 80% RPS by 2035	28%	15%	34%	0%	44%	0%	15%	30%
	2027	52%	27%		40%		32%	15%	42%	0%	48%	0%	20%	35%
	2028	52%	27%		45%		36%	15%	42%	0%	52%	0%	25%	40%
	2029	52%	27%		50%		40%	15%	42%	0%	56%	0%	30%	45%
	2030	60%	35%		55%		44%	15%	50%	0%	60%	0%	35%	50%
	2031	63%	35%		60%		48%	15%	50%	0%	64%	0%	40%	53%
	2032	66%	35%		65%		52%	15%	50%	0%	68%	0%	45%	56%
	2033	69%	35%		70%		56%	15%	50%	0%	72%	0%	50%	59%
	2034	72%	35%		75%		60%	15%	50%	0%	76%	0%	55%	62%
	2035	75%	45%		80%		64%	15%	50%	0%	80%	0%	60%	65%

These state policies were modeled individually but, for reporting purposes, were aggregated to reflect a west-wide "clean energy target" that takes into account the unique resource compliance accounting for each state policy. We compare a "clean energy penetration" against this calculated clean energy target to determine if policy goals were met in our operational analyses. In accordance with state policies, nuclear and hydro generation counted toward the clean energy target only when allowed for in state policy (or assumed state policy).

The study considered two future scenarios that are different from the Baseline Case in one or more ways. The goal of these scenarios was to evaluate the impacts of increasing and decreasing levels of system flexibility.

The **Integration Strategies** scenario tests several strategies intended to increase grid flexibility. This scenario was built from the Baseline Case and was studied in the security-constrained economic dispatch model. The scenario assumes a more diverse resource mix in the Northwest region, managed charging of EV loads, new transmission to help deliver renewable power to loads, the relocation of new generation causing transmission issues, and the addition of long- and short-duration storage to help with system flexibility. The Integration Strategies scenario was designed to investigate how system flexibility could be improved to help achieve renewable penetration consistent with the state policy targets assumed in this study.

The Baseline Case assumes a coordinated energy market develops in the West. The **Limited Regional Coordination** scenario was developed to evaluate system flexibility in a future where such markets do not come to pass. To reflect a future with sub-optimal day-ahead operations and transmission management, and therefore less flexibility, the study case adds in transmission service charges to all day-ahead and some real-time transactions between balancing areas, and limits transmission usage to the maximum of historical observations. The scenario does allow for real-time exchange between entities that participate or intend to participate in the Western Energy Imbalance Market (EIM). All other areas in the West do not have optimized real-time or day-ahead power markets and are assumed to revert to today's form of system operations with transmission wheeling rates between areas. This scenario was intentionally designed to reduce system flexibility, as compared to the Baseline Case, and more closely mimic the bilateral market structure the Western Interconnection has today.

Table 2 summarizes key assumptions for the Baseline Case, Integration Strategies scenario, and Limited Regional Coordination scenario. When columns in the table are consolidated between study cases, it means they have the same inputs for that assumption. Incremental changes from the Baseline Case to the scenario cases are highlighted in grey boxes with green text.

Table 2: Summary of Study Case Assumptions

	System Flexibility:	**Lower ↓**	**Benchmark**	**Higher ↑**
	Study Case:	**Limited Coordination**	**Baseline**	**Integration Strategies**
Assumptions	**Load Forecast**	Gross demand forecast of 165 GW in 2035 (0.8% CAGR)		**+ Managed EV charging**
	DG Penetration	7% by 2035 (4.2% CAGR during study period)		
	Resource Mix in 2035	Wind: 93,348 MW (23%) Solar: 91,935 MW (22%) Natural Gas: 85,648 MW (21%) Hydro/PS: 72,627 MW (18%) DG: 30,029 MW (7%) Coal: 16,708 MW (4%) Bio-Fuel: 2,630 MW (1%) Geothermal: 3,522 MW (1%) Nuclear: 5,790 MW (1%) Other: 7,064 MW (2%)		**Replaced 2,426 MW of wind with same amount of solar in NW**
	Coal Retirements	~12 GW of retirements by 2035		
	Clean Energy Target	Implied West-wide RPS: 33% in 2025; 63% in 2035		
	Enhanced Resource Siting	No: based on resource quality and transmission voltage		**+ Yes, based on congestion**
	Energy Storage	3.2 GW in 2026, 4 GW in 2035		**+ 4-hr storage: 2.1 GW by 2026 and 32.5 GW by 2035** **+ 12-hr storage: 0.6 GW by 2026 and 10.2 GW by 2035**
	Market Coordination	**+ Real-time only market based on EIM footprint** **+ No day-ahead market; Transmission service charges added** **+ Limits transmission capacity to historical usage**	Optimized real-time and day-ahead market coordination across entire West; no inter-BA wheels; BAs retain reliability obligations (e.g., operating reserves)	
	New Transmission	Approved projects only		**+ New upgrades**
	Curtailment Price	PTC eligible wind: $-40/MWh; all other wind and solar: $-15/MWh		
	Gas Price	Henry Hub: $4.77/mmBTU in 2035		
	New Resource Costs	Forecasts based on various sources, relied heavily on NREL 2018 Annual Technology Baseline (ATB)		

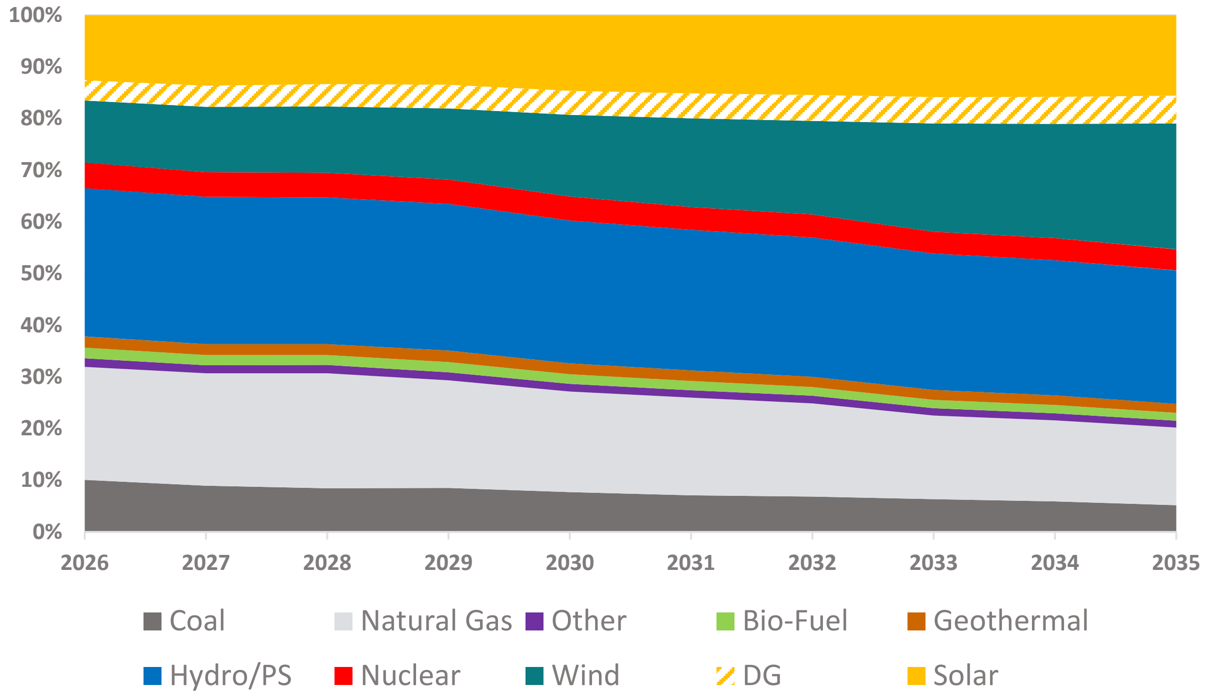
Key Findings

Findings from four study areas are presented below. These findings are based on the assumptions, modeling, and results described in the body of this report.

Resource Expansion

- **By 2035, 80% of the West's electricity needs could be provided by non-emitting resources.**[1]
- **Policy targets assumed in this study created demand for 9 GW/year of new wind and solar generation across the West.**
- **The capacity of gas-fired generation does not change significantly during the study period.**
- **During the study period, the West relied on wind, solar, gas, hydro, and nuclear – a diverse mix of resources – for most of its electricity needs.**

Figure 2: Annual Energy by Type (%) for Baseline Case



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[1] Based on retail sales.

System Operations

The operational analysis produced a number of key results for the three scenarios. Some of these results are summarized in **Table 3.**

Table 3: Key Results from Operational Analysis

	System Flexibility:	**Lower ↓**	**Benchmark**	**Higher ↑**
Study Year	**Study Case:**	**Limited Coordination**	**Baseline**	**Integration Strategies**
2026	**Curtailments** (%)	11%	3%	0%
2035		46%	20%	9%
2026	**Renewable Penetration** (%)	34%	36%	37%
2035		49%	52%	69%
2026	**CO2 Emissions** (Million Metric Tons)	165	161	159
2035		151	134	108
2026	**Production Costs** ($ Billions)	$12.1	$11.1	$10.7
2035		$11.3	$10.0	$7.8

- **States can achieve near-term policy targets – at least a 33% west-wide clean energy target in 2026 – with modest curtailments (3%) and without major changes to system flexibility.**

- **Long-term policy targets – which amount to a 64% clean energy target by 2035 – are difficult to achieve with incremental actions. The Baseline Case, which assumed a fully coordinated Western market, achieved a 2035 renewable penetration of only 52%, which is less than the clean energy target for that timeframe. This result suggests that, while market coordination does provide significant operational and transmission efficiencies (as outlined below), additional flexibility-enhancing actions and investments are also likely to be required to achieve policy goals in the 2030s.**

- **Mid-2020 policy targets are achievable without a coordinated wholesale market in the West, but not developing said market reduces system flexibility and causes increased curtailment (8% higher), increased CO_2 emissions (4 MMT/year higher), and higher operational costs ($1B/year increase).**

- **In the 2030s, the flexibility implications of not having coordinated wholesale markets becomes severe. Continuing "status quo" levels of wholesale market coordination causes curtailments to more than double compared to a scenario in which regional wholesale markets do materialize. Not adding this institutional flexibility to the system causes a $1.3B/year increase in operational costs, and a 13% increase in CO_2 emissions. Coordinated wholesale electricity markets and full use of existing transmission infrastructure can be an effective way to increase a given system's ability to integrate renewable resources.**

- Given that the Baseline case did not, on its own, result in the achievement of policy goals in the West, the study considered adding flexibility in the form of new transmission, a more diverse resource mix, new energy storage, and managed charging of EVs. A scenario implementing these strategies achieved a renewable penetration of 69%, which exceeded the 64% west-wide clean energy target. As compared to the Baseline Case, these flexibility strategies resulted in fewer curtailments (down to 9% from 20%), fewer CO_2 emissions (19% reduction) and lower system-wide operating costs (22% reduction).

- In the 2020s, regions often sell excess power to neighboring regions, which reduces curtailments. However, in the 2030s, most regions have high penetrations of renewables, and as a result, there are fewer buyers for excess generation because there are frequent conditions in which multiple regions simultaneously have excess power. Ultimately, this observation suggests that in the near-term, regions can increase system flexibility by exporting excess energy to other regions, but in the long-run, opportunities for such exports may decline as deep renewable penetrations become common across much of the Western Interconnection.

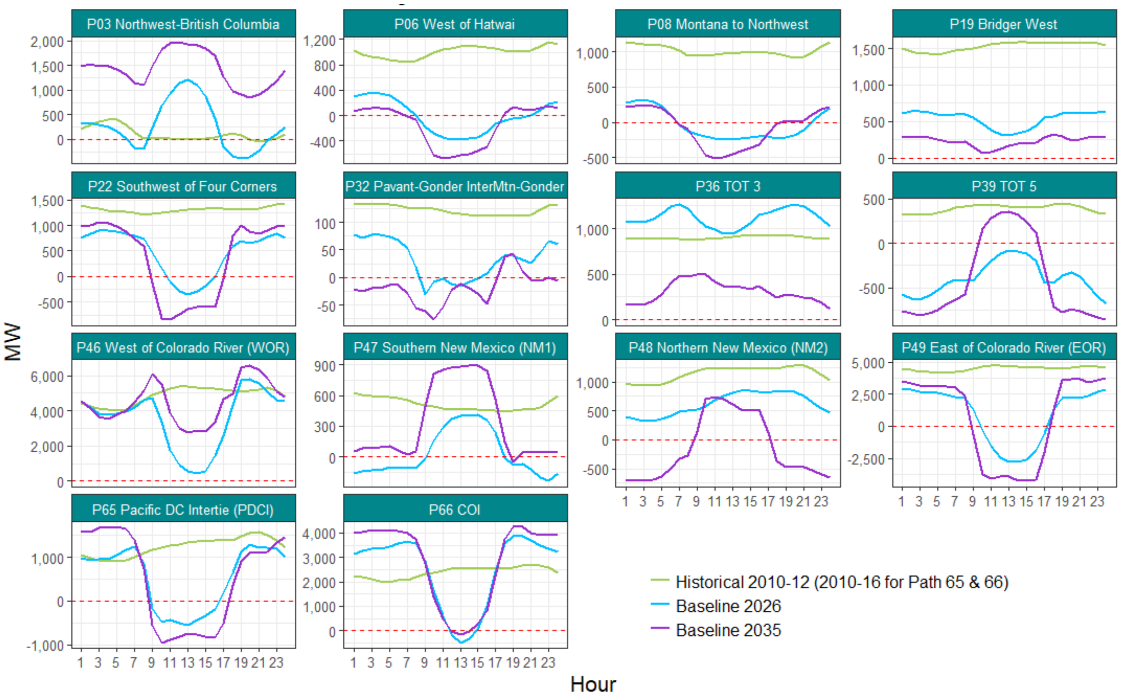
Transmission and Power flows

- Interregional power transfers are likely to increase in the coming years. Additionally, diurnal flow patterns may become the new norm. Lines that once changed flow direction seasonally, or never, change flow directions *daily* starting in the 2020s. Diurnal flow patterns are a significant departure from historical flow, and the trend is representative of the degree of interregional coordination and power exchange required to achieve high renewable penetrations in the West. Figure 3 demonstrates how average hourly flows in the Baseline Case differ from historical observations on key Western Electricity Coordinating Council (WECC) paths.

- The analysis of bulk-power system flows indicates that the near-term system is robust and there is very little congestion on the system in the 2020s. If the system is used up to its reliability limits, and if economic-based congestion management is used to manage generator dispatch and system flows, such as what might be achieved through regional market coordination, the bulk power system can accommodate renewable penetrations in line with 2026 state policy targets with minimal congestion.

- However, based on the resource siting assumptions used in this study, and the assumed transmission network, 2035 policy targets were difficult to achieve without assuming incremental transmission additions, even with economic-based congestion management and dispatch principles. This result suggests that, in the long-run, the West might require significant incremental transmission upgrades to achieve policy goals.

Figure 3. Average Hourly WECC Transfer Path Power Flows (average day) for Baseline 2026 and 2035 Cases versus Historical Flows (aMW)



- **Targeted congestion analysis was performed for the Northwest region and based on the study results for the 2026 and 2035 nodal simulations, congestion in the Northwest grid is minimal. Result indicates that if the Northwest system is used up to its reliability limits and a flow- or market-based congestion management system is used to manage power flows (such as what is assumed in our simulations), the bulk transmission interfaces in the Northwest can handle significant renewable penetrations without facing severe congestion.**

Northwest Resource Adequacy

- **A Northwest-focused study was performed to determine if the Baseline Case resource portfolio contained sufficient capacity for a reasonable evaluation of system flexibility. The analysis concluded that the Baseline Case portfolio contained sufficient resources for the demand levels used in the operational analysis.**

- **This study's evaluation of the Northwest region's adequacy need was highly sensitive to load assumptions. A sensitivity study increasing net peak demand by 14% (to 35,015 MW) significantly impacted the results. With this higher load forecast, which aligns with short-term adequacy assessment in the region (but is extrapolated out in time), the region has a need for more than 4,000 MW of firm capacity by 2027, on top of the firm capacity provided by 17 GW of new wind and solar resources added by this time.**

- **Given results that consider varying levels of generation builds and load forecasts, the Northwest region may require as few as 1,100 MW of new firm resources by 2030 or more than 4,000 MW of incremental firm resources by 2027 (or sooner). The more conservative forecasting and**

analysis methods suggest the need is larger and more urgent, while longer-term forecasts used in the Baseline Case for this study indicate that a capacity need exists, but it is smaller.

- **The firm capacity needs above could be met with gas-fired generation, but results also indicate that other resource options would be effective at meeting these capacity needs in the Northwest region, including Montana wind, long-duration storage of at least 12-hours, and increased access to market purchases. Solar and short-duration storage (4-hr) have some capacity value, but this value diminishes as the size of the region's capacity deficit increases. Demand response and Oregon/Washington wind had very low capacity values in the study.**

- **Results indicate that when Northwest generation shortages do occur, they are for extended periods and effect large amounts of load. In all studies, the average amount of lost load during curtailment events was more than 10 GW. In certain cases, load loss events last as long as 25 hours.**

Observations

Modeling results indicate that into the mid-2020's, current plans related to transmission and generation build out are likely to provide system flexibility in sufficient amounts to achieve state policy goals. This conclusion is based on the assumption that coordinated markets materialize by the mid-2020's. If this degree of market coordination *does not occur*, achieving policy targets in the 2020s becomes more difficult (and costly), but not infeasible from a technical standpoint.

In the 2030s, state policies (and therefore, renewable penetrations) are such that market coordination, alone, significantly enhances system flexibility but is not sufficient action to achieve policy goals. In addition to building out the requisite amount of renewable energy, investments in transmission, diverse generation mixes, and energy storage, along with customer engagement (such as managed EV charging), may be needed to meet policy goals.

This study did not investigate the cost tradeoffs of various flexibility solutions, nor did it deploy all of the available solutions in an optimized manner. More work is required in this area to help refine and optimize how the West moves towards achieving its future energy policy goals. For example, deeper investigation into how flexible operations of hybrid solar plus storage and wind plus storage resources is needed. Additionally, it will be critical that Western states energy planning for the 2030 and later timeframe begin to consider the fact that a large number of market participants (and regions) will, in many system conditions, have more electrical generation output than what they need. Therefore, in this time period, the ability to rely on inter-regional sales of excess power to other parties in the West may be limited during certain periods in which multiple regions have excess generation, and other strategies or investments may be needed to ensure policy goals are achieved.

1.0 INTRODUCTION

1.1 Background

In the years and months leading up to the publication of this report there has been a surge in new state energy policy across the West. The majority of these policies have the goal of decreasing electric sector carbon emissions by growing the amount of renewable energy on the grid through strengthened renewable portfolio standards (RPS) or clean energy requirements, new carbon cap and trade programs, "zero-emission" requirements, or a combination of these measures. Additionally, states are mandating that coal-fired generation be removed from electric rates, with some states passing securitization legislation, both of which can lead to the accelerated retirement of coal-fired resources. In addition to these policy drivers, voluntary renewable energy commitments are becoming more common, as represented in the rise of utility-adopted clean energy targets, community choice aggregators, customer demand for clean energy, "green" tariffs, and corporate procurement of renewable energy.

The following summarizes portions of key Western state policies enacted in 2018 and 2019:

- **California** – SB 100 was signed by Governor Brown in September 2018. The law seeks that 100% of retail sales be carbon-free energy no later than 2045 and requires a 60% RPS by 2030. SB 32 will require greenhouse gas (GHG) reductions of 40% below 1990 levels by 2030, which will be achieved primarily by using California's economy-wide cap-and-trade program.
- **Colorado** – Clean Energy Plan (HB 1261) allows for the securitization of costs associated with generator retirements and establishes statewide goals to reduce GHG emission levels to 80% below 2005 levels by 2030, and 100% by 2050. Colorado's Governor Polis has a goal of 100% renewable electricity by 2040.
- **Nevada** – SB 358, enacted in 2019, requires utilities to serve loads with 50% renewable energy by 2030, and sets a goal of 100% carbon-free resources by 2050;
- **New Mexico** – The Energy Transition Act (SB 489, passed in 2019) obligates utilities to a 50% RPS by 2030, an 80% RPS by 2040, and 100% renewables/clean energy by 2045, while also allowing for the securitization of coal assets;

- **Washington** – SB 5116 passed in 2019 and requires utilities to remove coal-fired power from their rates by the end of 2025 and to serve loads with 100% clean energy by 2045 (and 80% clean or non-emitting resources by 2030).

The details surrounding the implementation of these policies will take time to solidify. While we lack certainty regarding the regulatory regimes and compliance vehicles that will be used to implement these policies, utilities in these states (and others) are expected to add renewable resources in the coming years to meet these policy objectives. These policy drivers, combined with the continued decline in the cost of renewable resources, voluntary utility goals, and demands by customers for cleaner energy will cause the Western Interconnection's resource mix to evolve in the coming years. These changes to the resource mix will impact operational and transmission dynamics of the Western system.

Because of this forthcoming resource mix change, the Western Interstate Energy Board (WIEB) seeks to better understand a number of issues including:

- Operational and transmission implications;
- Impacts to inter-state power exchange;
- The effectiveness of a range of flexibility solutions or policies.

The purpose of the Western Flexibility Assessment is to investigate the flexibility and policy implications of a future grid in which renewable resources are deployed at levels consistent with enacted and foreseeable public policy requirements of Western states. The study provides government and industry decision makers insights on potential options to improve the flexibility of the grid.

1.2 Report Organization

The report is organized into sections, as follows:

- **2.0 Analytical Approach** summarizes the study methods, models and data sources used to perform the assessment.

- **3.0 Key Terms and Study Metrics** describe important terminology in the report, as well as study metrics and how they should be interpreted in the context of this assessment.
- **4.0 Baseline Case Assumptions** outlines key inputs into the Baseline Case.
- **5.0 Baseline Case Results** summarizes modeling outputs for the Baseline Case.
- **6.0 Scenario Cases** describes the assumptions and results for the two scenario cases: Limited Regional Coordination and Integration Strategies. Both of these scenarios were developed starting from the Baseline Case. Results are presented in terms of changes from the Baseline Case focusing on operational and transmission flow patterns.
- **7.0 Production Costs and Carbon Emissions** summarize results in these areas for all study cases.
- **8.0 Findings and Discussion** responds to the core questions which were answered through this study, presenting the most critical takeaways and potential next steps for future analyses.
- **9.0 Technical Appendix** captures technical details not included in the body of the report.

1.3 Study Cases and Core Questions

This study investigates long-run challenges in meeting recently enacted or anticipated public policy targets. The study focuses on a period beginning in 2026 and concluding at the end of 2035 – ten full years during which there are expected to be significant changes as the West moves toward meeting policy goals. This study draws all of its findings from a sequential series of modeling studies designed to emulate grid conditions that may occur during the study period.

The study centers around a **Baseline Case**, which is this study's expected future and is substantially based on existing and reasonably projected clean energy policies and commitments. It reflects existing generators, recent and near-term generation additions, recent load forecasts (including energy efficiency), and assumes that only major transmission projects with approved means of cost recovery are built. The Baseline Case also assumes that enacted public policy requirements are met. In addition, instead of today's primarily bilateral power trading market, the Baseline Case assumes that an integrated and optimized Western power market exists.

To help frame the study, which was structured around the aforementioned Baseline Case, the study's Technical Advisory Committee assisted Energy Strategies in establishing core questions that guided the analysis. The core questions the study set out to answer are broken into the five categories below:

1. **Long-run Resource Needs**
    - Given the new and consequential policies enacted across the West, how much and what types of generation resources may be required to achieve policy goals?
    - To what degree are thermal generation retirements expected to occur?
    - Does the achievement of the state policies, as modeled, appear to be feasible on a regional basis?

2. **Northwest Resource Adequacy**
    - What is the nature of the Northwest's long-term capacity challenge, and to what extent can the Northwest hydro system be relied on to help meet capacity needs under policy-compliant futures with increasing amounts of renewables?
    - How much new gas-fired generation is necessary to ensure future adequacy as renewable resources are added to the system?
    - Can energy storage and demand-side resources defer the need to construct thermal resources in the Northwest? Are these resources capable of meeting long-duration capacity needs?

3. **Operational Challenges**
    - How much renewable curtailment does the study forecast for different Western regions as state energy policies are met?
    - How much of curtailment is driven by transmission limitations versus operational constraints?
    - How might clean energy policies impact capacity factors of the thermal fleet, and how might the thermal fleet operations change over time (e.g., ramping)?

- When do the most difficult operating conditions occur, and how do those conditions change over time?

4. **Transmission and Power flows**
    - As state policies are implemented, how might intra- and inter-regional transfers and/or congestion be impacted? Do power flows become more consistent over time?
    - How might changes to inter-regional transfer capability (or flexibility) impact power flows?
    - How do transmission stress conditions change over time?

In addition to answering these core questions, using primarily the Baseline Case study results, the effort also investigates flexibility solutions that could be helpful as more renewables are added to the system. To this end, two scenario studies were considered to evaluate the implications of increasing or decreasing system flexibility. The two scenarios are described below.

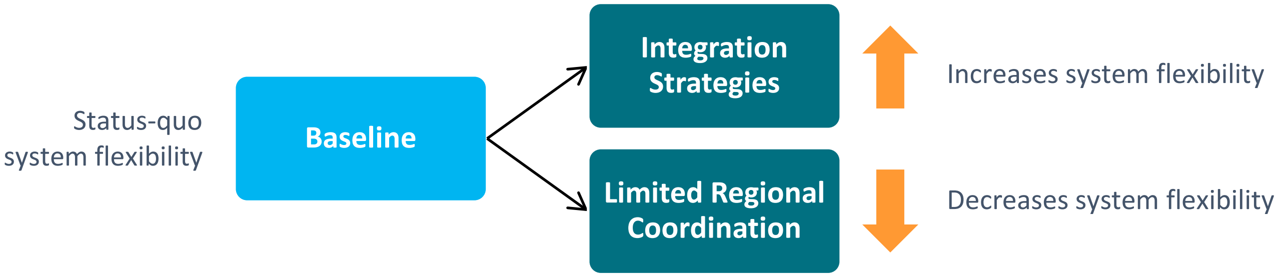
1. **Integration Strategies** is a scenario designed to *increase* system flexibility through large-scale deployment of medium- and long-duration storage, new transmission capacity, a more diverse resource mix, and managed charging of EV loads. These changes are made to the Baseline Case not as a forecast of exact actions that need to be taken (since this portfolio is non-optimal) but as an investigation into the effectiveness of a suite of flexibility tools that may be available to utilities. Ultimately, the goal of this scenario is to determine what types of incremental actions might be required for the West to meet policy targets through 2035. However, this scenario does not capture the entire suite of technologies or policies that may be required (or efficient) to manage new operational issues caused by the changing resource mix.

2. **Limited Regional Coordination** is a counter-factual scenario intentionally designed to *reduce* system flexibility, as compared to the Baseline Case, by modeling a system that is less integrated and optimized, from an operational and power trading standpoint. While the Baseline case assumed day-ahead wholesale markets across the West, the Limited Regional Coordination does not. In addition, we assumed that transmission capacity in the scenario is limited to its historical usage level and that the optimization of power trading (free of transmission hurdles) is limited to real-time transactions, consistent with entities participating or planning to participate in the Western Energy

Imbalance Market (EIM). This counter-factual scenario was studied to help understand the implications of status-quo operational methods, in which most of the power in the West is traded bilaterally and there is "pancaking" of transmission rates that lead to inefficient wholesale market outcomes.

The study cases used in this assessment are summarized below in **Figure 4**. The two scenarios are designed to test changes to the Baseline Case that increase and decrease system flexibility.

Figure 4: Summary of Study Cases



2.0 ANALYTICAL APPROACH

At the study's core was an effort to perform modeling that estimates resource expansion, system operations, and transmission reliability of the Western grid during a period in which states make significant progress toward ambitious policy goals. This section addresses the study's analytical approach including an overview followed by a review of modeling tools, study design, study footprints, and important caveats.

While this section does address certain aspects of model setup, it does not address modeling input assumptions used to form the Baseline Case or the scenario cases – assumptions are addressed in Section 4.0 and Section 5.0, respectively. Beyond this section and those mentioned above, additional details on analytical methods and assumptions are included in the Technical Appendix.

2.1 Overview

To assist WIEB in developing a deeper understanding of operational, adequacy, and transmission implications associated with resource mix changes that may occur in the West between now and 2035, the analytical approach in this study required a *sequential* Baseline Case study evaluation that, in order:

1. Establishes a reasonable starting point in 2026 that considers load forecasts, approved transmission, and planned resource/storage additions and retirements;
2. Considers incremental energy policy during the 10-year study period (2026-2035), including estimates surrounding the amount of renewable energy that must be added to the system based on state policies, resource availability, load forecasts, and market dynamics;
3. Uses capacity expansion modeling to synthesize the above-mentioned constraints and requirements, creating lowest-cost resource portfolios for the West that, if deployed over the 10-year study period, will be sufficient to meet policy goals and high-level reliability thresholds;

4. Performs an hourly-timestep, security-constrained, economic dispatch evaluation of the capacity expansion model’s resulting resource portfolios, reflecting detailed constraints of the transmission grid;
5. Assesses Northwest-focused resource adequacy (for the portfolios mentioned above) using a regional model which reflects non-power related constraints placed on the operation of hydroelectric facilities;
6. Evaluates transmission reliability (based on dispatch conditions derived from the portfolios above) using an alternating current (AC) power flow simulation to conduct steady-state contingency analyses which reflects Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC) reliability criteria; and finally
7. Develops and studies scenarios that consider flexibility levels higher and lower than the Baseline Case, exploring the effectiveness of renewable integration tools, like energy storage and regional coordination, in meeting state policy objectives and addressing system inflexibility.

These analytical steps were performed in sequence to investigate system flexibility challenges and potential solutions during the 2026-2035 study period.

2.2 Modeling Tools

We used four modeling tools in a sequential and, in certain cases, iterative fashion to perform the studies necessary for this Western Flexibility Assessment. Each of these modeling tools, summarized in **Table 4**, are purpose-specific and their assumptions were coordinated such that each tool was used for its explicit purpose, and together they formed varying perspectives of the same future. The coordination of this data is described in more detail within Section 2.3 (Study Design).

Table 4: Summary of Modeling Tools

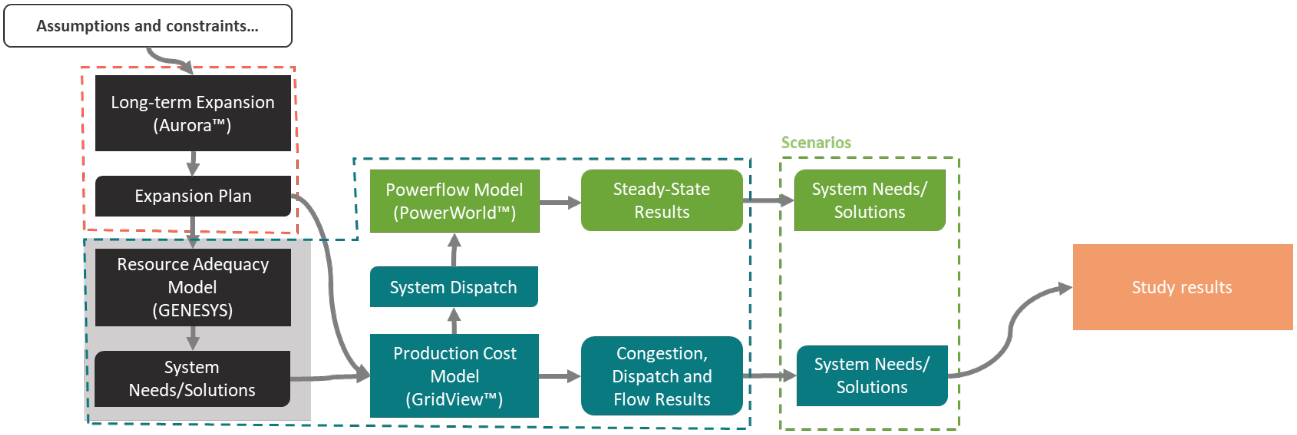
Study Tool	Category/Type	Use
AURORA™	Long-term capacity expansion model, hub-spoke representation of the grid	✦ Produces an optimal, lowest-cost resource expansion that meets reserve margins, reliability constraints, and has resource deployment with energy content sufficient to meet policy goals ✦ Resulting resource expansion plans are used for more detailed analysis in other tools
GENESYS[2]	Stochastic resource adequacy tool customized for Northwest system	✦ Performs thousands of chronological hourly simulations each with varying river flows, temperature-based loads, wind & solar generation, and forced outages to determine the Northwest system's resulting loss of load probability (LOLP), i.e., the number of simulations which had a supply shortfall as a percentage of the total number of simulations ✦ The LOLP is used to judge the resource adequacy of the Northwest system in comparison with the region's current 5% LOLP standard ✦ Different projected resource build-outs are iteratively tested to determine which represent resource adequate futures
GridView™	Nodal security-constrained economic dispatch model with hourly granularity	✦ Simulates hourly system operation subject to real-world constraints such as transmission limits, generation operating characteristics, and load levels. Simulations were run with normal transmission facilities in service and did not consider transmission contingencies. ✦ A highly detailed transmission system is represented in the model, including substations, transformers, and transmission lines ✦ Results are used to assess hourly operations, transmission flows, and ability to deliver renewables consistent with policy goals
PowerWorld™	Power flow analysis software	✦ Performs full AC power flow simulation and steady-state contingency analysis ✦ Results are used to identify thermal loading violations in the system

Each of the tools listed above were set up to meet the needs of this study. What follows is a short description of the model set-up for each tool. Detailed assumptions about model set-up can be found in Section 4.0 for the Baseline Case, and Section 6.0 for the scenario cases, and in the Technical Appendix.

2.3 Study Design

The Baseline Case was evaluated through a rigorous, multi-stage study process designed to investigate the flexibility needs of the Western system over the 2026-2035 time-horizon. Scenario cases were studied using only the production cost modeling tool. The study process is outlined below in **Figure 5**.

Figure 5: Schematic of Study Design



A consistent set of Baseline Case assumptions were a core input into each of the four study models. We coordinated assumptions such as load growth and resource additions across each of the four models.

The first step in the analysis was a long-term capacity expansion study performed using the AURORA™ model. The study, which included every year and sampled hourly operations for one week per month, starting in 2026 and ending in 2035, evaluated the system's energy, capacity, and public policy needs and built out the lowest-cost mix of resources sufficient to meet these needs. The resulting capacity expansion plan, which specifies the resources added to the system

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[2] Generation Evaluation System Model

and their physical location (by state), served as an input assumption into subsequent modeling efforts, which we describe below. The capacity expansion modeling also produced results related to the West's resource mix and emissions.

The Northwest adequacy study was performed using the GENESYS software using methods and metrics familiar to the Northwest region. We performed studies for years 2026, 2030, and 2035.[3] We fed the Baseline Case expansion plan from AURORA™ (described above) into the GENESYS model for each study year. In this way, the Baseline Case study of Northwest adequacy needs reflects actions that may be taken between now and the study year to achieve public policy goals. Also, this portion of the study included several sensitivity analyses evaluating the timing and nature of Northwest adequacy issues for varying sets of resource portfolios.

We also input the Baseline expansion plan into the production cost model (GridView), and we ran studies for the 2026 and 2035 study years – bookending the study period. We mapped each resource addition identified in the expansion plan to high-voltage substations in the appropriate geographic region such that the nodal capabilities of the GridView modeling were retained. The substations for new resources were selected based on their proximity to the high-voltage transmission system and well-established renewable development areas (e.g., high wind speed areas for wind resources). The production cost modeling study was the primary tool used to evaluate operations, generation curtailments, net load ramping, and transmission flows. It also generated information about system production costs and emissions.

Finally, in the last step of the study process to evaluate the flexibility of the Baseline Case system, stressed single-hour conditions from the production cost model were selected and "exported" into the power flow modeling tool. In the "export," we were able to maintain alignment between the two model's representation of loads, generation, and transmission. The two stressed conditions – a high load and a high renewables condition – were evaluated in 2026 and 2035. The transmission reliability analysis focused on evaluating the ability of the

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[3] Since the study year for Northwest adequacy issues stretches over the winter months, the studies were actually performed for 2026-2027, 2030-2031, and 2035-2036. The GENESYS study months run from October through September of the next (e.g., the 2027 study year begins October 2026 and ends September 2027).

transmission system to deliver power to loads under "contingency" conditions, which reflect reliability conditions when transmission lines are lost. The goal was not to determine if the grid was definitively reliable or not (as this was not a transmission planning exercise and did not address all aspects of grid reliability), but rather to explore the "sufficiency" of the transmission system in terms of its ability to reliably transfer the simulated generation output to loads on a bulk-power scale.

The study years considered for each of the four modeling tools are summarized in **Table 5**, below.

Table 5: Study Years Evaluated for Each Model

Study Type →		Long-term capacity expansion	Northwest adequacy	Production cost model	Powerflow reliability
Study Tool →		**AURORA™**	**GENESYS**	**GridView™**	**PowerWorld™**
Study Year	**2026**	✓	✓	✓ ✓⃝	✓
	2027	✓	×	×	×
	2028	✓	×	×	×
	2029	✓	×	×	×
	2030	✓	✓	×	×
	2031	✓	×	×	×
	2032	✓	×	×	×
	2033	✓	×	×	×
	2034	✓	×	×	×
	2035	✓	✓	✓ ✓⃝	✓

✓ *Baseline Case Study performed*

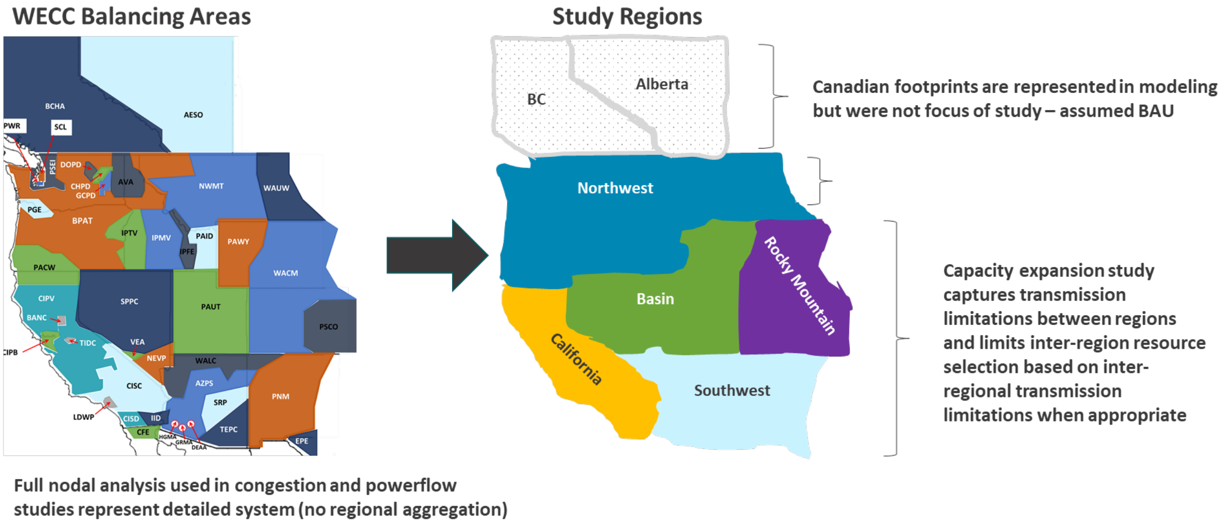
✓⃝ *Scenario Case Studies performed*

× *No study*

2.4 Study Footprint

The study accounted for the entire Western Interconnection in the analysis. However, the characterization of study footprints varied by model. For example, the power flow modeling and production cost modeling did not require zonal or regional representation (in terms of transmission capacity modeling) as the study represented the full transmission system in those tools. However, capacity expansion modeling (AURORA) and resource adequacy modeling for the Northwest (GENESYS) represent the system on a zonal and regional basis. To address this variance among study tools, we created five study regions that, for *reporting purposes*, were held constant across all models: Northwest, Basin, Rocky Mountain, California, and Southwest. Throughout the rest of this report, the term “region” refers to one of these five study footprints.[4] To highlight each region, the mapping between Western balancing areas and the study regions is shown below in **Figure 6**.[5]

Figure 6: Study Regions and Notes


WECC Balancing Areas

Study Regions

Canadian footprints are represented in modeling but were not focus of study – assumed BAU

Capacity expansion study captures transmission limitations between regions and limits inter-region resource selection based on inter-regional transmission limitations when appropriate

Full nodal analysis used in congestion and powerflow studies represent detailed system (no regional aggregation)

The study scope focused on implications for grid flexibility in Western states. Western states in this study include California, Oregon, Washington, Idaho, Nevada, Utah, Arizona, New Mexico,

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[4] Canadian areas were represented in the modeling but were not included in the study reporting.

[5] The Northwest region footprint aligns with the footprint used by the Northwest Power and Conservation Council.

Colorado, Wyoming, Montana and the portion of Texas in the Western Interconnection. When this study refers to "the West," "Western states," "Western system," or other similar terms, it is referring to the electrical footprint of these states. When the study refers to the entire Western Interconnection, it is referring to the entire Western Interconnection, inclusive of the Western states and British Columbia, Alberta, and northern Baja California.

2.5 Study Considerations

This study was an ambitious undertaking in terms of its technical scope (multiple modeling tools), duration (10-year study period), and broad geographic focus (the entire Western system). We made many simplifying assumptions to complete the study. Further, this type of forward-looking modeling is based on a series of assumptions about the future and, in many cases, much less precise then modeling results might imply.

For these reasons, the reader should consider the following study considerations, among others not listed, when reviewing and analyzing the study results:

- **The study's broad geographical scope means that it is not positioned to address highly nuanced issues for a particular state or sub-area (including individual utilities). The regional focus on the Western U.S. means that these results may not apply to smaller footprints, including sub-regions, states, and utilities.**

- **The study is mostly a deterministic analysis and did not have the benefit of robust sensitivity analysis (due to the multi-model approach and ambitious scope). The study considers a narrow set of potential futures and resource portfolios. Indeed, varying these assumptions will result in different study results. Additional sensitivity analysis is one of the areas recommended for follow-up analysis.**

- **This study does not address all aspects of renewable integration or system flexibility. For example, it does not consider sub-hourly operations, nor does the reliability analysis investigate grid stability and dynamic issues. These are areas worthy of continued research.**

- **The study made numerous assumptions about the siting of new resources, retirement dates of existing resources, and other supply-side assumptions. While our best judgment was used in forming these assumptions, we accept that many different outcomes in these areas are possible or even likely, and this study captures a narrow set of potential outcomes.**

- **The transmission analysis imbedded in this study is not designed to replicate or supplant local, regional, or interconnection-wide planning efforts. The study methods and approach were tailor-made for the purpose of this study, which focused on grid flexibility and renewable integration. The work performed for this study is not sufficient to support the construction of any specific transmission projects or upgrades as (1) the outcomes of this work are entirely a product of the input assumptions; and (2) the scope of this study was not focused on evaluating transmission alternatives against one another. Further, the scope of work is not sufficient to make any determinations around grid reliability. Our goal was to evaluate if we had approximately the right amount of transmission assumed in order for transmission to not be a flexibility barrier.**

- **The study incorporates advanced economic modeling that leads to forecasts around future resource portfolios. This modeling is not sufficient to supplant modeling done on more granular scales, such as that performed in IRPs. Moreover, while the study does forecast certain coal retirements on an economic basis, this work is not equivalent to a detailed evaluation of coal retirement economics which is typically conducted by utilities prior to making retirement decisions.**

- **This study took several months to complete. We based the analysis on data and assumptions that were available to us at different points in that timeframe. This timing lag is inherent to extended study efforts, such as this one.**

These factors notwithstanding, we are confident in the reasonableness of the assumptions relied on for this study and consider the results to be an informative and useful road-map for utilities, transmission providers, generators and policy makers as the region continues to navigate the evolving resource mix while preparing to implement and comply with new state policies.

3.0 KEY TERMS AND STUDY METRICS

We dedicate this section of the report to explaining key study metrics and terminology used in this report to describe system flexibility challenges and solutions.

3.1 Curtailment

The term “curtailment” is used widely in this study. The term is complicated and deserves more background and explanation. National Renewable Energy Lab (NREL) defines curtailment as “a reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis.”[6] While curtailment can technically happen to any generator, it most commonly is used to describe the unused output of solar and wind facilities since those generators have no fuel cost and therefore are often considered “must-take” resources, whereas dispatchable resources, such as gas-fired generators, can be backed down when their power is not needed. Historically, wind and solar generators have been concerned about curtailment because lost production can impact project economics when the project’s compensation is tied to delivering power to the grid.

Excess generation, transmission congestion, or general system inflexibility – such operating constraints or “must-run” requirements – are all potential drivers of curtailment. System operators convey the need for curtailment through two primary means. The first is direct communication (e.g., a phone call) from the system operator to the generator requesting that the unit be turned down or off. These directives are sometimes used to help maintain system reliability (e.g., an urgent need to balance load and generation). The second approach is economic-based and is common in organized markets. In organized markets wind and solar resources can submit market bids that result in automatic curtailment if the price does not

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[6] Bird, L., Cochran, J., & Wang, X. (2014, March). Wind and Solar Energy Curtailment: Experience and Practices in the United States. Retrieved from https://www.nrel.gov/docs/fy14osti/60983.pdf

exceed or meet their bid. For many generators, this bid price will be equal to the economic opportunity cost of their potentially lost generation. The opportunity cost of undelivered generation can be impacted by the generator's power purchase agreement, the value of renewable energy credits, and the value of production tax credits (for wind). For this study, we assumed that wind and solar generation bid negative prices into the market.

This study assumes that renewable curtailment is the "default" flexibility solution. The modeling embeds curtailment as an automatic economic solution for "overgeneration" and system inflexibility. When operational modeling results in pricing that is lower than the opportunity cost of renewable generation, curtailment occurs. Several factors can cause pricing to drop below the curtailment price, including:

- **Transmission congestion –** When transmission constraints cause generator output to be "bottled up" in a given area, power prices in that area will fall because of congestion costs. Prices fall because that constrained generation is less valuable to the system. If transmission will not let it flow to loads that need it, and there is already enough local generation to serve load, it follows that this trapped energy is less valuable so it will have a reduced price due to transmission congestion.

- **Overgeneration –**Given traditional economic incentives to deliver as much renewable energy as possible, there can be conditions in which a given area has energy production above its load. This is more common on systems with high penetrations of renewables because, today, renewables are typically not operated as fully dispatchable resources. Since energy prices in a given market are based on the cost to provide the next unit of energy (the marginal cost of energy), overgeneration conditions can cause that price to fall because wind and solar generation (along with other must-take resources) have low, or negative, opportunity costs for their generation.

- **Grid inflexibility –** Another factor that can cause prices to drop (which can lead to curtailments), is grid inflexibility. It can take multiple forms. Slow ramp-up/ramp-down rates for thermal generators can, for instance, require generators to stay online which can exacerbate overgeneration. Minimum operating levels can also impact thermal units' ability to back down, which impacts flexibility and overgeneration. Inefficient trade is another example of grid inflexibility.

These factors and their costs are embedded in the location-specific power prices calculated in the operational modeling used in this study. To the extent that modeling calculates that transmission constraints, inflexibility, or overgeneration occur to the degree such that they cause prices at a given generator to fall below their minimum bid price, the generator output will be economically curtailed until the price recovers. In this way, the term "curtailment" in this study is used as an indicator of a lack of system flexibility since its presence can be linked back to the factors described above.

We should expect an efficiently operating system with high penetrations of renewables to have *some* curtailment. Recent studies, and even some power purchase agreements, have begun to challenge the idea that all renewable generation output must be delivered. One example is study work performed by First Solar and E3, which suggests that operating today's solar plants more flexibly – meaning operating them *not* to maximize energy delivery – might help to resolve, not worsen, operational challenges.[7] While this study does use curtailments as a flexibility metric, it does not assume that curtailments are uneconomic, nor does it assume that all curtailments on the system should be eliminated. It does, however, use the existence of large numbers of curtailment system wide as an indicator of an inflexible system.

3.2 Net Load Ramping

This study uses net load ramping as a flexibility metric that gauges how system operations are changing under high penetrations of renewables. We calculate net load in a given hour for a given footprint as the gross demand (adjusted for distributed generation and energy efficiency) minus output from wind and solar production. This net load value will vary hour-to-hour. During high wind and solar periods, net load can be relatively small. However, on solar- or wind-rich systems, when that generation type falls off, the net load can increase quickly. This hour-to-hour increase, or "ramp," means that other generation must be available to come online to serve increasing amount of net load. In this manner, net load ramps are a metric we use to track system flexibility.

Net load ramps in this study can be met with local generation in a given region or state, or with neighboring generation imported on the transmission system. This is one of the reasons why

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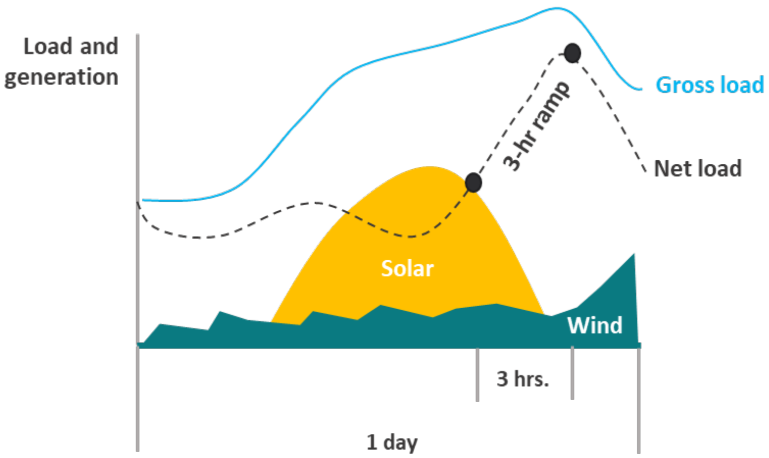
[7] (2018). Investigating the Economic Value of Flexible Solar Power Plant Operation. First Solar and E3. Retrieved from https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

transmission is important to grid flexibility – net load ramps often need to be addressed with a combination of local *and* imported power.

An example of a 3-hour net load ramp is provided below in **Figure 7**. In this study, we use the 3-hour metric, which calculates the change in net load over a given 3-hour period. Net load ramping can also be negative, although this study does not focus on this metric. Negative net load ramping can occur when, for instance, solar product ramps up in the morning causing net load to drop.

Figure 7: 3-hr Net Load Example



3.3 Transmission Metrics

This study reports out a number of transmission related metrics. To understand these metrics, it is important to become familiar with WECC Paths and our methods for defining interregional flows.

WECC paths are interfaces, which are groups of lines that have a defined rating or maximum reliable flow level. We report flows on WECC paths because they group the major lines in the system and are often between major regions. **Figure 8** shows a map of the WECC paths.

Figure 8: WECC Paths[8]

In this study, we also report flows on an interregional basis. The transmission flows between the study regions, which are defined in Section 2.4, are based on groupings of one or more WECC paths. Since WECC paths are represented in our detailed models, we can aggregate flows on one or more WECC paths to represent total flows between regions.

We report two transmission use metrics:

- **U75 –** This is the number of hours (or percentage of the year) in which flows are at or above 75% of the path's rating. A path with high U75 value is a heavily utilized path. A heavily utilized path is not necessarily a congested path.
- **U99 –** This metric reports the number of hours (or percentage of year) in which flows are at or above 99% of the path rating. Flows at this level mean the path is congested or very close to being congested. Transmission congestion is an economic problem used to described lines that are

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[8] Map sourced from the WECC.

loaded to their maximum levels and, if it were not for their maximum rating, would be loaded further to support economic transfers. In certain conditions, low-cost power will be trapped behind transmission constraints. Since the generation is trapped, higher-cost power must be used to serve loads. The cost of using the high-cost power instead of the trapped low-cost power is the cost of transmission congestion.

The study addresses limited aspects of transmission reliability and performed the analysis at a relatively high level. Transmission planning analysis was well beyond the scope of this study, and the study does not seek to identify specific problem areas on the grid, nor does it seek to evaluate specific transmission alternatives. Both of these outcomes are infeasible for this wide-ranging effort. The reliability analysis in this work rolls up study results into area-level findings. Listed below are important terms that will help the reader understand the analysis.

- **Bulk Electric System (BES) –** generally all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher, and does not include facilities used in the local distribution of electric energy.[9]
- **Contingency –** a disturbance in the power system involving the loss of one or more elements. In this study the contingencies are limited transmission lines and transformers with voltages at or above 200 kV and are "P1", meaning the disturbances only involve the loss of a single element (in contrast to comprehensive transmission planning studies whose continencies include the loss of multiple elements and lower-voltage lines).
- **Thermal overload –** when the flow on a transmission line or transformer exceeds its modeled thermal rating. The thermal rating represents the current-carrying limit that cannot be exceeded without causing an unsafe situation (e.g., damage to equipment, transmission line sagging too much and violating ground clearance safety standards).
- **Dispatch condition –** the state of the system as described by either the output of the resources in the system or the load that the resources as a whole are serving. The setpoints of the resources throughout the system are representative of a plausible system operating situation, and the situations that represent one type of stress or another are the focus of transmission planning studies.

The study did not analyze voltage deviations, voltage stability, or any dynamic or transient (sub-20 second) issues. Our limited study scope is one of the reasons that we do not purport this to be a transmission planning study.

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[9] Full Bulk Electric System definition in NERC Glossary of Terms: https://www.nerc.com/files/glossary_of_terms.pdf#page=6

3.4 Resource Adequacy

Resource adequacy is considered at two places within the study. First, regional resource adequacy is considered for all five Western study regions via the capacity expansion modeling performed using AURORA. As described in detail in the Technical Appendix, that modeling approach uses load forecasts, assumed planning reserve margins, assumed capacity values from existing and new resources, along with firm import/export assumptions, to inform a least-cost optimization that ensures regional resource portfolios have sufficient capacity to meet peak demands.

While this study is focused on the entire West, it does feature deeper examination of certain Northwest-focused issues based on the study's funding sources (e.g., Oregon and Washington State). For this reason, the study included a more extensive resource adequacy review for the Northwest region. The primary purpose of this Northwest-focused analysis was to determine if the resource portfolio developed via capacity expansion modeling for use in the operational analysis had sufficient capacity relative to the load forecast. This Northwest-focused adequacy analysis was performed using the stochastic GENESYS (Generation Evaluation System) model (described in Section 2.2), which has advanced hydro system modeling that is better suited, relative to the capacity expansion modeling, to evaluate the Northwest region's power supply.

The NWPCC uses GENESYS to assess the adequacy of the Northwest power supply. The tool is used not only by the NWPCC but also by numerous other regional entities to perform adequacy assessments, hydro flow studies, and economic analyses of hydro dispatch changes. GENESYS is an hourly simulation stochastic model that can be used to identify conditions in which the region does not have sufficient power supply to serve loads, subject to statistical variations in load (temperature), wind generation, solar generation, streamflow (hydro conditions), and the forced outage of thermal generators. The metric used to evaluate the Northwest region's resource adequacy in this assessment was Loss of Load Probability (LOLP), which indicates the likelihood that load is curtailed, calculated as the number of simulations performed that have curtailment divided by the total simulations. LOLP is a good indicator of the frequency of loss of load events, but two resource portfolios with the same LOLP can have very different underlying events since the metric does not capture the magnitude or severity of the load curtailment event. The NWPCC adopted a resource adequacy standard in 2011 that requires that the LOLP for the region be less than 5% for five years into the future. The NWPCC is currently considering revisions to this standard, so this study uses the standard only as a reference point.

This study's first priority, in considering Northwest adequacy, was to ensure that the Baseline Case resource portfolio used to evaluate flexibility issues was not "short" on capacity to begin with. Making this determination was a study priority because (1) the capacity value of the Northwest hydro system is "dynamic" and was estimated but not fully captured in the expansion modeling, especially in a portfolio with high penetrations of renewables, and (2) if the operational analysis resource portfolios do not include sufficient capacity in the Northwest (or any other region), there is the potential that flexibility issues may be overstated or identified because a lack of system capacity.

For context on this issue, **Table 6** summarizes several recent studies addressing Northwest resource adequacy.

Table 6: Summary of Recent Studies on NW Resource Adequacy

Study	Approach and Footprint	Findings on Capacity Needs
Seventh Northwest Conservation and Electric Power Plan – NWPCC (2016)	Stochastic model (GENESYS); NWPCC footprint	• System Needs Assessment compared circa 2016 resource capability against load forecasts – no incremental resources modelled • Adequate through 2020, 0-3 GW need in 2021, 2-6 GW need by 2026, need of 4.3-10 GW by 2035, depending on load forecast and EE and DR
Pacific Northwest Power Supply Adequacy Assessment for 2023 – NWPCC (2018)	Stochastic model (GENESYS); NWPCC footprint	• Assumes **no planned resources** beyond those already sited or licensed, 7th Power Plan energy efficiency, 200 MW of incremental DR from 7th Power Plan • 300 MW of need in 2021 with the additional need for 300-400 MW in 2022

Study	Approach and Footprint	Findings on Capacity Needs
Resource Adequacy in the Northwest – E3 (2019)	Stochastic model (RECAP); Greater Northwest footprint	• 1.2 GW capacity deficit in 2018 and 8 GW and (based on loss-of-load expectation (LOLE) metric) • System adequate in 2030 if planned coal retirements replaced with 5 GW of gas or if all coal is retired and replaced with 16 GW of gas • **Includes no planned resources** (wind/solar/storage in 2030 equal to what exists in 2018)
2018 Pacific Northwest Loads and Resources Study or "The White Book" – BPA (2019)	Deterministic; NWPCC footprint	• The region has 0.2 GW capacity deficit in 2020 and 1.6 GW deficit starting in 2021, based on 120-hour capacity metric • No incremental generation beyond what exists today
Northwest Regional Forecast of Power Loads and Resources 2020 – 2029 – PNUCC (2019)	Deterministic; NWPCC footprint	• Assumes critical water conditions and no incremental solar/wind/storage (beyond recent acquisitions and under-construction facilities); <200 MW of incremental DR; no non-firm purchases from IPPs • 4-5 GW shortage by 2026 and 5.5 GW by 2029

As the nature of capacity challenges in the Northwest crystallize, this study adds to that discussion by evaluating adequacy challenges *in the context of system flexibility needs* using planning models and methods familiar to Northwest stakeholders. The study was based on its own set of assumptions and was performed using models, assumptions, metrics, footprints, and resource portfolios that differ from what those used in studies listed above. For example, this study used a NWPCC long-term load forecast entirely appropriate for long-term system planning and operational analysis. However, relative to near-term forecasts that are created for and commonly used to evaluate near-term adequacy needs, this longer-term load forecast relatively lower. Results of the adequacy evaluation for the Northwest portfolio are in Section 5.2.

3.5 Other Important Metrics and Terms

What follows are addition key terms that are used commonly in presenting study results.

- **Production cost –** Capture the costs associated with power production in a given footprint. Production costs include fuel costs, generator start-up costs, variable/fixed operations and maintenance costs, among other costs. Since wind and solar generation have low or no operational costs, and no fuel costs, it is common for the addition of these types of resources to cause system-wide production costs to decrease as dispatchable/thermal resources are displaced (and their fuel and operational costs are avoided). This study reports production costs for single study years (e.g., 2026), so they are presented as annual values. Production cost changes do not capture all system costs, including capital costs associated with new generation investment, one-time fixed costs or other capital improvements for existing generators, or the costs associated with building new transmission.

- **CO_2 emissions –** The burning of fossil fuels creates CO_2 emissions. The metric is important to this study because many of the policies driving the resource mix change at issue in this study were created to reduce CO_2 emissions. While this study does not have the goal of identifying a path toward a certain amount of emission reductions, it does report this metric to indicate if state policies are generally reducing emissions, and to inform us about how different flexibility solutions impact emissions. Flexibility solutions that are complementary to state emission reduction goals may be preferred options, all else being equal.

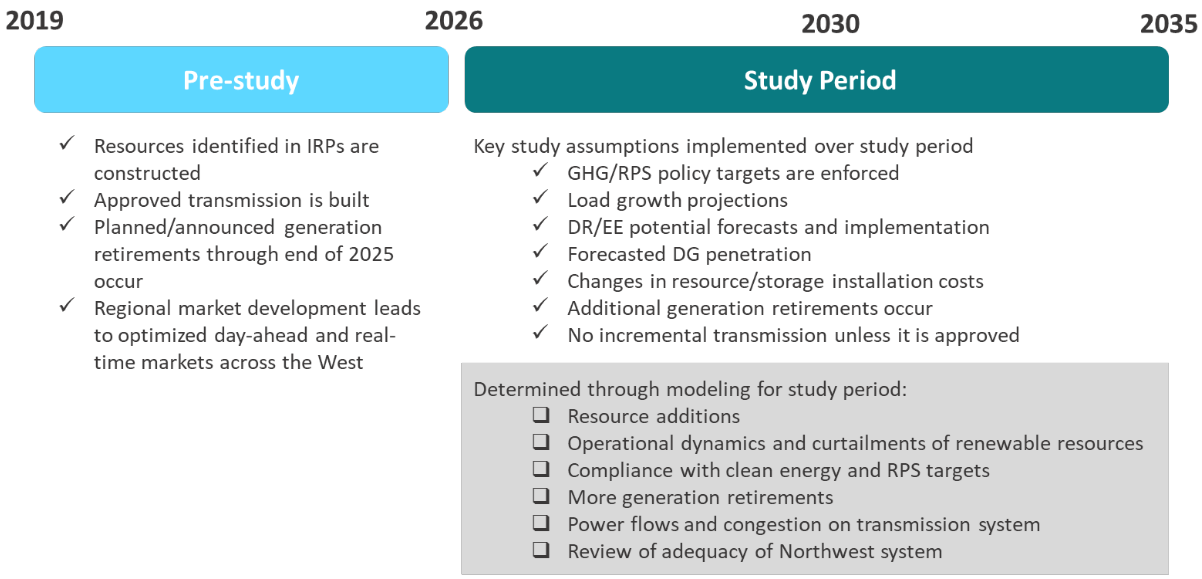
- **Clean Energy Target and Clean Energy Penetration –** The study attempts to reflect the nuances of each Western state's RPS and/or clean energy standard. In most instances, RPS resources include wind, solar, bio-fuel, and geothermal. In addition to these RPS resources, our assumed modeling of clean energy standards adds certain hydro and nuclear generation serving Washington, and nuclear generation serving Arizona. To simplify our reporting, we refer to the aggregate demand of these "policy compliant" resources as a west-wide "clean energy target". We refer to the supply of these resources, in aggregate, as the "clean energy penetration". These terms and the calculations that support it properly account for variances among state policies.

4.0 BASELINE CASE ASSUMPTIONS

The Baseline Case is the focus of this study. It is a long-range study platform that broadly investigates flexibility challenges on the Western system. The case attempts to reflect future state policy requirements across the West. It is not, however, a prediction or forecast of the future system – it is a compilation of assumptions that, in aggregate, are one of many potential futures. This section summarizes assumptions used to develop the Baseline Case. Additional assumptions are in the Technical Appendix.

Assumptions used to define the Baseline Case fall into two categories. The first category of assumptions falls into the “pre-study” window, and addresses system changes between now and 2026. An example might be coal retirements that occur before 2026. “Study period” assumptions are those that take place during the study window (2026-2035). These could take the form of load projections for each study year, or forecasted declines in the capital cost of renewable resources over the study period. **Figure 9** summarizes both categories of assumptions, along with certain study output.

Figure 9: Baseline Case Input and Output Summary



- ✓ Resources identified in IRPs are constructed
- ✓ Approved transmission is built
- ✓ Planned/announced generation retirements through end of 2025 occur
- ✓ Regional market development leads to optimized day-ahead and real-time markets across the West

Key study assumptions implemented over study period
- ✓ GHG/RPS policy targets are enforced
- ✓ Load growth projections
- ✓ DR/EE potential forecasts and implementation
- ✓ Forecasted DG penetration
- ✓ Changes in resource/storage installation costs
- ✓ Additional generation retirements occur
- ✓ No incremental transmission unless it is approved

Determined through modeling for study period:
- ☐ Resource additions
- ☐ Operational dynamics and curtailments of renewable resources
- ☐ Compliance with clean energy and RPS targets
- ☐ More generation retirements
- ☐ Power flows and congestion on transmission system
- ☐ Review of adequacy of Northwest system

The following sections describe the Baseline Case assumptions for this study. Additional details are available in the Technical Appendix.

4.1 Resource Assumptions and Capacity Expansion Modeling Inputs

Baseline Case existing resource assumptions, including announced retirements, were sourced from multiple databases

Existing generation, as of January 1, 2019, was based on the following databases: Energy Information Administration (EIA), WECC Anchor Data Set (ADS), and, CAISO Transmission Planning Process. Planned or potential retirement dates of thermal generators were included in the Baseline Case and were sourced from IRPs and the data sources listed above. Capacity expansion modeling logic was allowed to advance, but not delay, assumed retirement dates.

Assumptions for planned resource additions were also incorporated into the Baseline Case

Based on IRPs, we assumed that new resources planned before 2026 are constructed. In the case of California, we assumed all resources identified in the California Public Utilities Commission (CPUC) Preferred System Plan from the 2017-18 IRP cycle are built in the amounts, technologies, and locations as specified in that plan. The process used to establish the Baseline Case resource portfolio is outlined in **Figure 10. Figure 11** summarizes the Western U.S. resource mix at the end of 2025, by type, as compared with today (2019).

Figure 10: Process to Define Resources in the Baseline Case

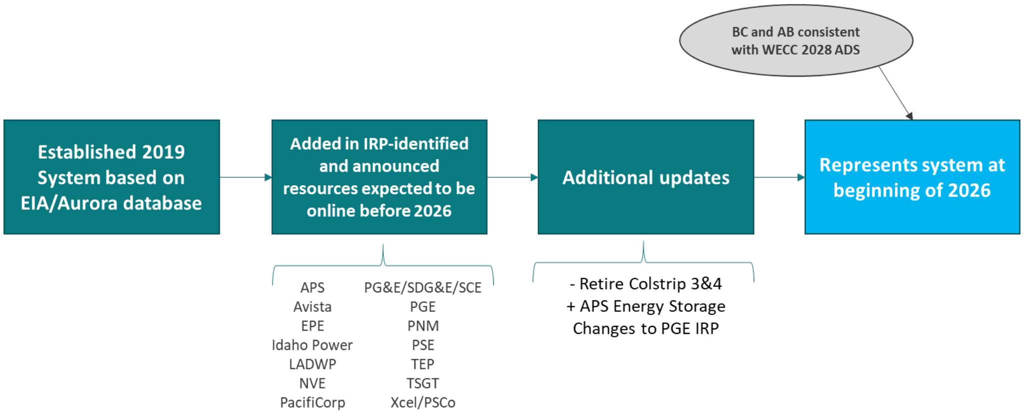
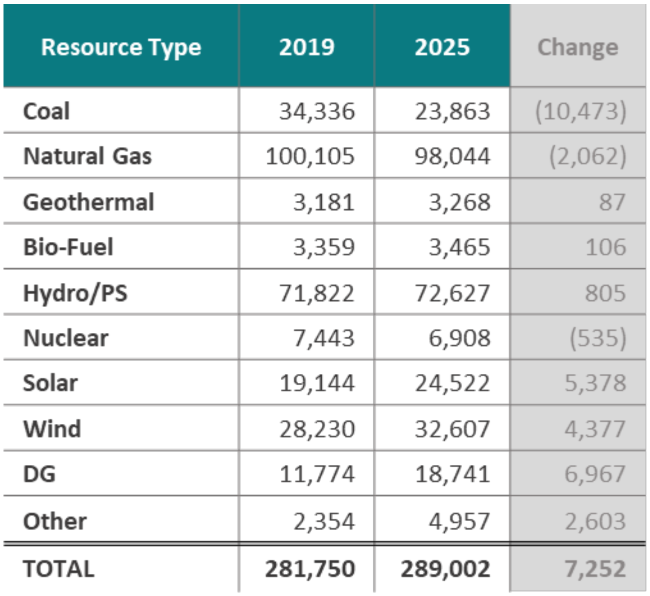


Figure 11: Summary of Existing and Planned Resources in Western U.S. (MW)



Resource Type	2019	2025	Change
Coal	34,336	23,863	(10,473)
Natural Gas	100,105	98,044	(2,062)
Geothermal	3,181	3,268	87
Bio-Fuel	3,359	3,465	106
Hydro/PS	71,822	72,627	805
Nuclear	7,443	6,908	(535)
Solar	19,144	24,522	5,378
Wind	28,230	32,607	4,377
DG	11,774	18,741	6,967
Other	2,354	4,957	2,603
TOTAL	281,750	289,002	7,252

Capital expansion modeling determined incremental resources additions (beyond existing and planned) and economic retirements for Baseline Case during the 2026-2035 study period

We developed new resource options available for selection within every state and region. New resource types included biomass, natural gas aero-derivative combustion turbine, natural gas frame combustion turbine, natural gas combined cycle, geothermal, solar photovoltaic (PV), 4- and 8-hour lithium-ion storage, 12-hour pumped storage, and wind (onshore and offshore).

There were technical limits placed on the following resources: biomass, solar PV, pumped storage, and wind. We applied these limits on the state level. Solar, wind, and biomass limits for each state were based on research performed by NREL.[10] Technical limits for pumped storage were based on S&P Financial's database of proposed pumped storage projects.

Each new resource option had a fixed cost (capital cost, property tax, and insurance) and fixed O&M cost trajectories for the entire study period based on their location and the load each resource might serve. Unless existing transmission capacity was already available or was assumed to be available based on assumed thermal retirements, the fixed cost of out-of-state new resource included the fixed cost of new transmission (e.g., Montana coal).

Capital expansion modeling represented transmission transfer capability between regions and included a simplified representation of ancillary service requirements

Transmission constraints were interregional and based on WECC Transfer Path transfer capabilities, as shown below in **Figure 12.**

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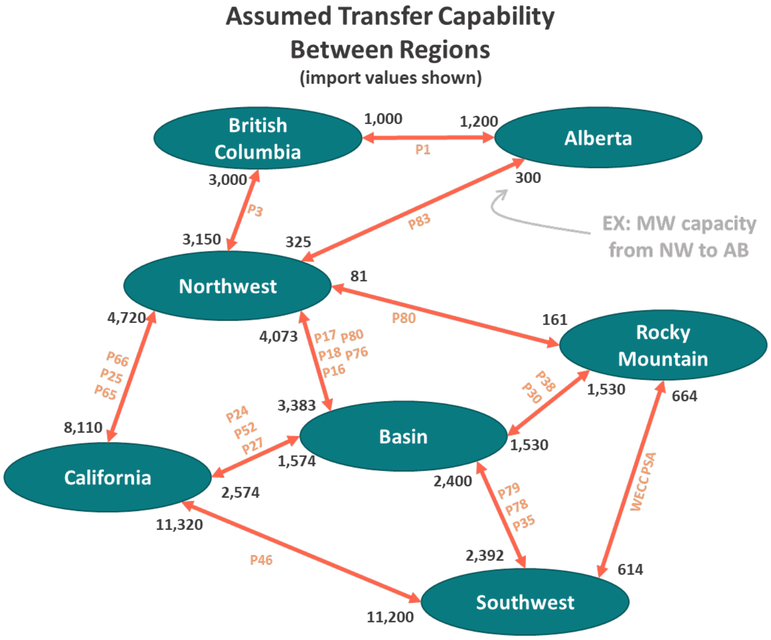
[10] Lopez, A. (2012). U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. Retrieved from https://www.nrel.gov/docs/fy12osti/51946.pdf

Figure 12: Baseline Case Transmission Constraints in Capacity Expansion Model



Operating reserve requirements were assumed to be 6.5% of the hourly load in each region. This approximated the FERC 789 requirement for contingency reserves (the greater of 3% of generation plus 3% of load or the largest single generator's output), plus a small amount (0.5%) extra that would not overlap with the estimated 1.5-2.5% of load requirement for regulation and load following ancillary services (i.e., the resources contributing toward the contingency resources were assumed to simultaneously contribute all but 0.5% of the regulation and load following requirement).

We modeled planning reserve margin (PRM), firm import, and firm export constraints for each region based on recent NERC Long-Term Reliability Assessments, NWPCC Resource Adequacy Assessments, and remote resource power purchase agreements (PPAs). The assumptions are summarized below.

Figure 13: Planning Reserve Margin Assumptions

Region Name	Planning Reserve Requirement (%)	Firm Imports (MW)	Firm Exports (MW)
Alberta	**11%**	0	0
Basin	**13%**	Through 2030: 159 After 2030: 81	0
British Columbia	**11%**	0	0
California	**15%**	9,891 MW	0
Northwest	**13%**	3,000 MW	Winter: 1,000 MW Summer: 2,000 MW
Rocky Mountain	**17%**	0	Through 2030: 159 After 2030: 81
Southwest	**15%**	0	1,500 MW

Capacity value assumptions were based on generation type, location, and development status. The capacity value for new wind, solar, and storage resources was assumed to decrease commensurate with their energy penetration in each portion of the Western system, to represent the decline in capacity value for the marginal MW of installed capacity.

4.2 Transmission Assumptions

> ***To not overstate the capabilities of the transmission system (thereby masking flexibility challenges), the Baseline Case reflects the existing system plus new transmission projects that have regulatory approval for cost recovery***

Planned transmission projects assumed to be built by the beginning of 2026 included all those approved by the CAISO Board of Directors and the Gateway West Segment D.2 transmission project. No other major incremental transmission expansions were included in the Baseline Case.[11]

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[11] The Integration Strategies scenario ultimately resulted in a larger transmission build. See Section 6.0 for details.

4.3 Load and Policy Assumptions

Baseline Case reflects recently enacted and potential policies that could impact the amount of renewable power on the system

The study represented a broad range of RPS & clean energy policies, from those recently enacted, to those proposed or announced, to potential clean energy requirements driven by procurement trends and voluntary targets in some areas. **Table 7** provides a summary of the assumed RPS and clean energy targets, including the reasonably assumed trajectory to meet the deadlines enacted by each state. More details regarding these policies are described below. Based on these policies, renewable energy generally included wind, solar, bio-fuel, and geothermal power throughout the system, but also included nuclear and hydro power serving Washington and Arizona. For reporting purposes, we have reconciled the various policies and created a “clean energy target” for the West, as described in Section 3.5.

Table 7. Assumed RPS/Clean Energy Target by State

	Year	California	Northwest						Intermountain		Rockies		Southwest	
		CA	OR		WA		ID	MT	NV	UT	CO	WY	AZ	NM
	2020	33%	20%		15%		**4%**	15%	22%	0%	30%	0%	10%	20%
	2021	33%	20%		15%		**8%**	15%	22%	0%	30%	0%	11%	20%
	2022	33%	20%		15%		**12%**	15%	**26%**	0%	30%	0%	12%	20%
	2023	33%	20%		**20%**		**16%**	15%	**26%**	0%	**32%**	0%	13%	20%
	2024	44%	20%		**25%**		**20%**	15%	**34%**	0%	**36%**	0%	14%	20%
	2025	44%	27%		**30%**		**24%**	15%	**34%**	0%	**40%**	0%	15%	**25%**
Study Period	**2026**	44%	27%	**Cap and Invest**	**35%**	**Carbon Cap and 80% RPS by 2035**	**28%**	15%	**34%**	0%	**44%**	0%	**15%**	**30%**
	2027	52%	27%		**40%**		**32%**	15%	**42%**	0%	**48%**	0%	**20%**	**35%**
	2028	52%	27%		**45%**		**36%**	15%	**42%**	0%	**52%**	0%	**25%**	**40%**
	2029	52%	27%		**50%**		**40%**	15%	**42%**	0%	**56%**	0%	**30%**	**45%**
	2030	60%	35%		**55%**		**44%**	15%	**50%**	0%	**60%**	0%	**35%**	**50%**
	2031	63%	35%		**60%**		**48%**	15%	**50%**	0%	**64%**	0%	**40%**	**53%**
	2032	66%	35%		**65%**		**52%**	15%	**50%**	0%	**68%**	0%	**45%**	**56%**
	2033	69%	35%		**70%**		**56%**	15%	**50%**	0%	**72%**	0%	**50%**	**59%**
	2034	72%	35%		**75%**		**60%**	15%	**50%**	0%	**76%**	0%	**55%**	**62%**
	2035	75%	45%		**80%**		**64%**	15%	**50%**	0%	**80%**	0%	**60%**	**65%**

- The study represented very recently enacted RPS/clean energy policies in Washington, Colorado, New Mexico, and Nevada.[12] Nuclear and hydro generation counted toward the Washington clean energy standard.
- The Baseline Case assumes that California, Oregon, and Washington all have carbon cap-and-trade programs (by 2026) with a common allowance trading platform.
    - The assumed carbon price in the study was based on the 42 MMT case of the CPUC RESOLVE 2018 IRP Model, starting at $24.76/Ton and growing to $43.08/Ton (nominal dollars) from 2026 through 2035.
- While Arizona and Idaho do not have major incremental energy policies, procurement trends, and voluntary targets by utilities in those states prompted us to assume incremental clean energy requirements for this study. In Arizona, we assumed that nuclear generation would count toward a potentially future clean energy standard.
- The study assumed California and Montana policies at their enacted levels, with no incremental requirements assumed.[13]
- The state RPS/clean energy policies, which were modeled individually, resulted in an effective West-wide clean energy target of 33% by 2026 and 64% by 2035, as shown in **Figure 14**.
    - Resources allowed to contribute to these policy goals included wind, solar, bio-fuel, and geothermal power throughout the system as well as nuclear and hydropower in Washington and Arizona.[14]

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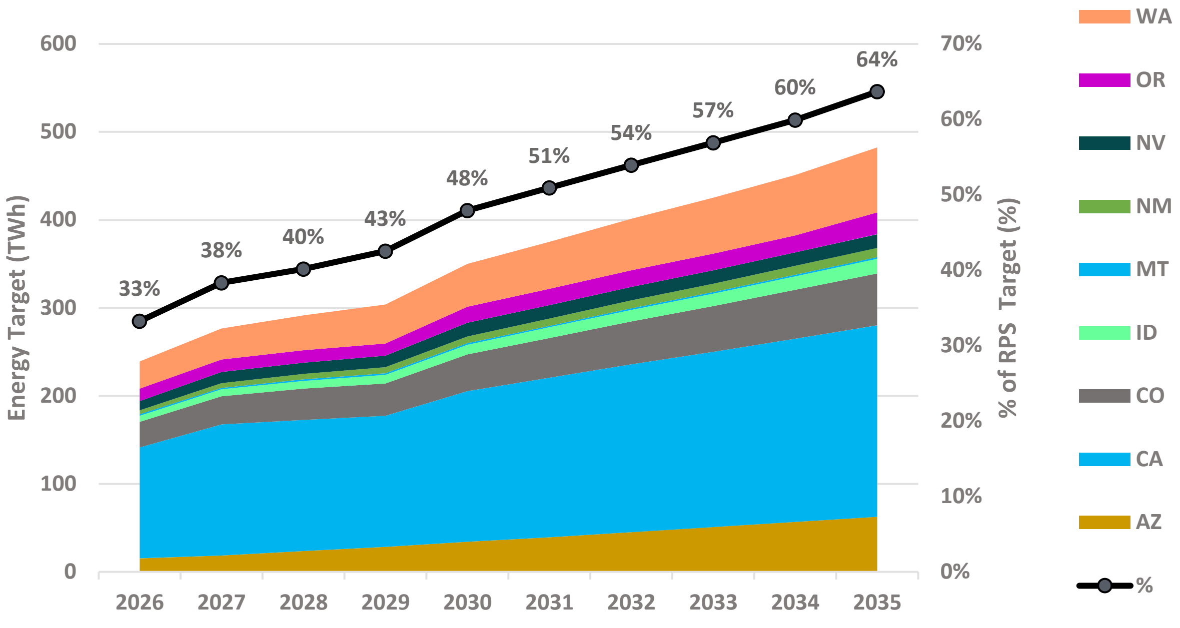
[12] Notably, these policies were not yet final when the study work was performed. As such, the policy targets are only approximate to what was ultimately legislated in these states.

[13] No mandatory RPS or clean energy policy existed in Utah and Wyoming, so the study did not impose incremental requirements for load in these states. Utah does have a mandatory RPS, but it is only mandatory if cost effective, thus no RPS was modeled.

[14] In reality select small hydro facilities are allowed to contribute toward the California RPS; however, this nuance was not represented in the analysis and hydropower in California was not allowed to contribute to the California RPS.

Figure 14: Baseline Case Clean Energy Target (%) and State Breakdown (GWh)



The Baseline Case assumes that regional market expansion occurs such that real-time dispatch and day-ahead unit commitment are optimized across the West, with very low trade barriers

Transmission capacity was assumed to be used up to its reliability limits, instead of being capped in accordance to the contract path structure used across the West today. Market modeling reflects day-ahead and real-time market construct with no transmission wheels and no limitations on exports from the CAISO balancing area. In this manner, the Baseline Case assumes that one tool for enhanced system flexibility, increased market coordination, is realized.

Load growth in the Baseline Case is forecasted based on NWPCC 7th Power Plan, California Energy Commission (CEC) 2018 Integrated Energy Policy Report (IEPR), and WECC Loads & Resources Data

We created 1-in-2 hourly loads shapes for each Balancing Authority Area (BAA) for the entire study period. The study's demand and energy efficiency (EE) forecasts were based on the

NWPCC 7th Power Plan, CEC 2018 IEPR Update, and the annual WECC load and resources data collected at the beginning of 2018.

- The forecasted Northwest demand and EE were matched to the NWPCC 7th Power Plan's net-of-conservation energy forecast.
- For California loads, the study used the CEC 2018 IEPR Update's Mid demand and additional achievable energy efficiency (AAEE) forecasts. The CEC had already developed hourly shapes for each CAISO investor-owned utility (IOU) through 2030, so the annual peak and energy growth of these hourly shapes were used to forecast the IOU loads further, through 2035.
- Based load forecasts for the Basin, Rocky Mountain, and Southwest regions on the load forecasts in the WECC load and resource data.[15]

Baseline Case assumed DG penetration of 7% in the Western U.S. by 2035, led by California whose DG was projected to reduce annual retail sales by 12%

Distributed Generation (DG) constituted behind-the-meter (BTM) rooftop solar PV and was forecasted based on the NREL Regional Energy Deployment System (ReEDS) study. This study applied the state-level ReEDS data to balancing authority areas (BAA) based on their share of each state's load. The study used the CEC 2018 IEPR Update's Mid committed and so-called "Mid-Mid" additional achievable PV generation hourly shapes for each CAISO IOU through 2030, and their capacity growth was assumed through 2035.

Generation and storage costs continue to decline

As shown in **Figure 15**, all the levelized cost of energy for many types of new resources were projected to show significant declines within the study timeframe. The study assumes that the production tax credit expires at the end of 2020 and the investment tax credit is reduced to 10% for solar resources coming online after 2023.

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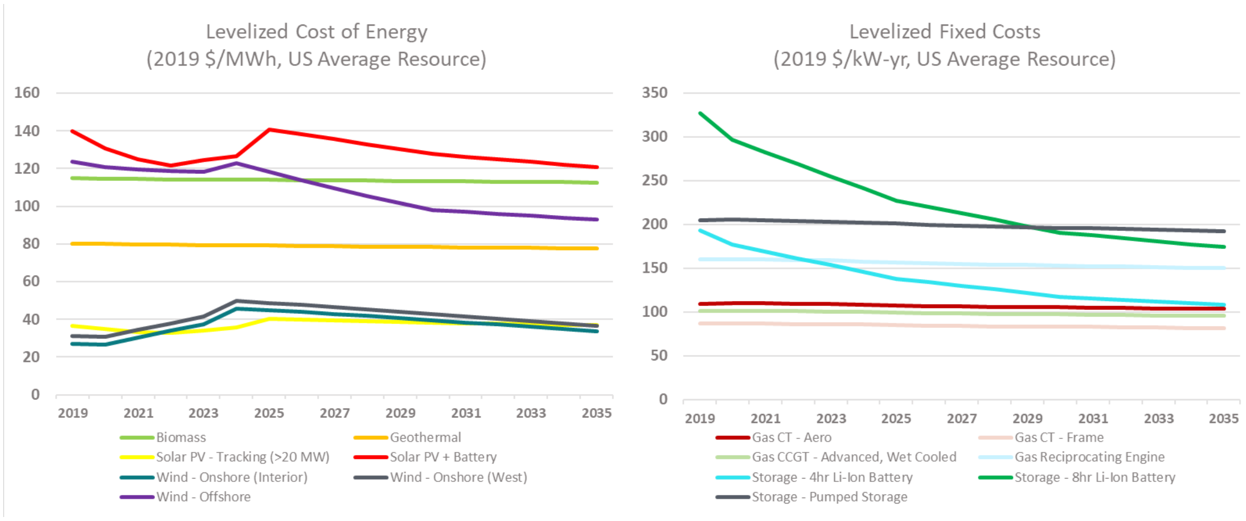
[15] Only incremental energy efficiency imbedded in these load forecasts were included in the study.

Figure 15. Levelized cost of energy for new resource options



Levelized Cost of Energy
(2019 $/MWh, US Average Resource)

Levelized Fixed Costs
(2019 $/kW-yr, US Average Resource)

4.4 Other Assumptions

> ***The Baseline Case accounts for incremental electric load growth due to increasing penetration of electric vehicles, but does not include load adjustments for building electrification or other increases in electrical use not already captured in regional forecasts***

The majority of incremental EV charging load is assumed to be located in the Northwest and California. The assumed EV shape does not reflect "managed charging" policy or price responsive charging habits. It had weekday- and weekend-specific profile developed by the CEC and NREL using the Electric Vehicle Infrastructure Projection Tool (EVI-Pro).[16] **Figure 16** shows how the average day's profile for EV load changes during the 2026-2035 study period and **Table 8** summarizes the forecasted annual EV load energy.

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[16] "California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025": https://www.nrel.gov/docs/fy18osti/70893.pdf

Figure 16: Average Day's EV Charging Load in 2035

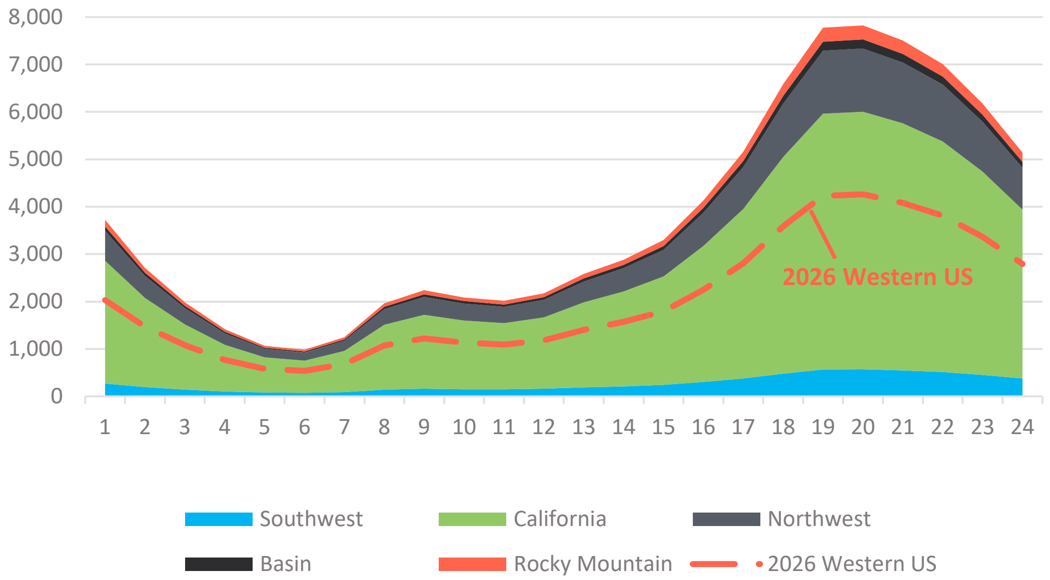

Table 8. EV Load Forecast[17]

EV Load Energy (MWa)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	1,474	1,897	2,592	5.8%
Northwest	360	511	638	5.9%
Basin	45	70	107	9.1%
Rocky Mountain	55	89	141	10.0%
Southwest	101	164	258	9.8%
Total	**2,034**	**2,731**	**3,736**	**6.3%**

Northwest hydro modeling reflects capabilities of hydro system consistent with modeling approaches used by the Bonneville Power Administration (BPA) and the NWPCC

The approach captures the unique characteristics of the Northwest hydro system using methods and tools familiar to the region, accounting for the ability to shift hydro output to other periods

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[17] The Northwest forecasted EV load is consistent with the 7th Power Plan which assumes 1.5 million vehicles by 2035

based on the availability of wind and solar output. The capital expansion modeling used the aggregated hydro dispatch from GENESYS as hourly minimum and maximum hydro output constraints to reflect the Northwest hydro's real-life 2-, 4-, and 10-hour sustaining peaking capabilities based on non-power related constraints such as those to protect, mitigate, and enhance fish and wildlife populations that could be adversely affected by the hydroelectric system.

Wind and solar curtailment cost assumptions estimate opportunity cost of generation

The study assumed curtailment costs for wind, solar, and hydro resources. Wind and solar generators had negative curtailment costs based on assumptions for production tax credit (PTC) value and the market for delivered renewable energy credits (REC). To simplify the assumptions, the study assumes wind installed after 2020 has no PTC value. **Table 9** summarizes the curtailment cost assumptions. [18]

Table 9. Curtailment Cost assumptions

Fuel Type	Installation Year or Other Description	Curtailment Cost ($/MWh)	Reasoning
Wind	2015 or before	-15	$15/MWh REC value (Assumed PTC period expired)
	After 2015 & through 2020	-40	$15/MWh REC and $25/MWh PTC value
	After 2020	-15	$15/MWh REC value
Solar	All	-15	$15/MWh REC value
Hydro	NWPCC	-300	Already bounded to the NWPCC GENESYS operating limits
	Non-NWPCC	-50	Assumptions from CAISO 2028 Default PCM

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[18] See pages 37-39 for an explanation of the term "curtailment" and the rationale for focusing on curtailment of wind, solar and hydro. Hydro had very high negative curtailment costs so as not to disrupt its constrained operation. Hydro bounded by NWPCC operating limits had the lowest curtailment prices since their output already represented levels within their reliable 2-, 4-, and 10-hour sustaining peaking capabilities and, therefore, they'd be the least likely to curtail their output.

The gas price forecasts for the Baseline Case were based on the Northwest Power and Conservation Council forecast from October 2018

The Northwest Power and Conservation Council Henry Hub natural gas price forecast was preferred over other forecasts because of its intra-year volatility, shown in **Figure 17**. **Table 10** provides the average annual Henry Hub natural gas price assumptions for more reference. Forecasted Baseline case coal prices using data from the 2018 EIA Annual Energy Outlook (AEO). Gas transportation costs were included in both the capital expansion analysis (AURORA) and operational studies (GridView).

Figure 17. Henry Hub Natural Gas Price Forecast (2019$/mmBtu), provided by NWPCC

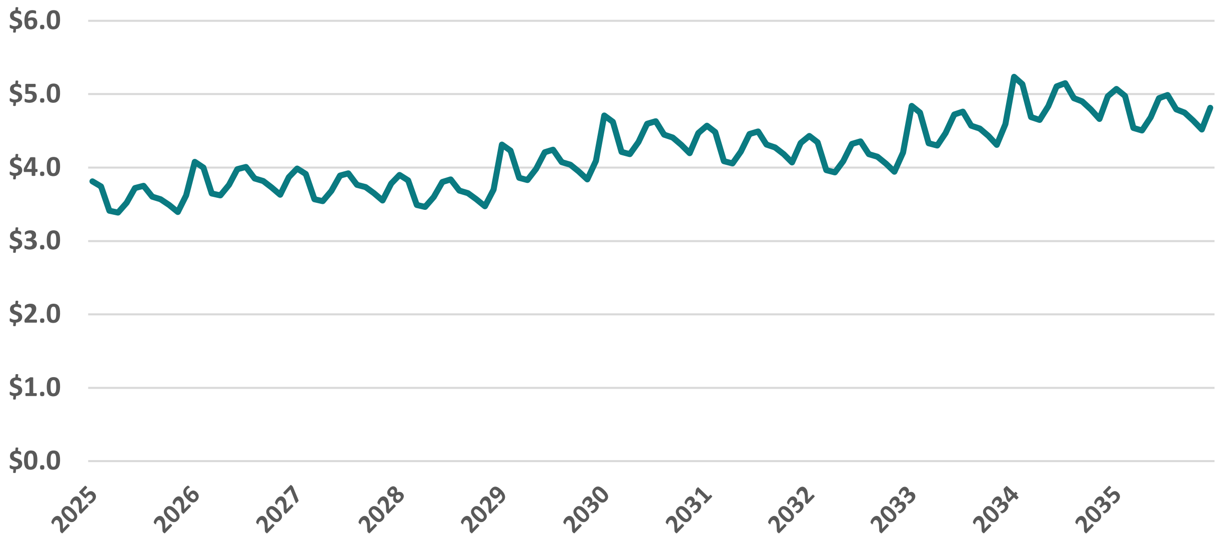


Table 10. Annual Averages of Henry Hub Natural Gas Price Forecast (2019$/mmBtu)

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
3.832	3.749	3.667	4.055	4.429	4.295	4.164	4.551	4.923	4.769

5.0 BASELINE CASE RESULTS

This section covers Baseline Case study results pertaining to resource expansion; resource adequacy in the Northwest; operational performance of the system; and transmission sufficiency and power flows. These results were generated using the various modeling tools described in Section 2.2, and are based on the assumptions outlined in Section 4.0.

5.1 Resource Expansion

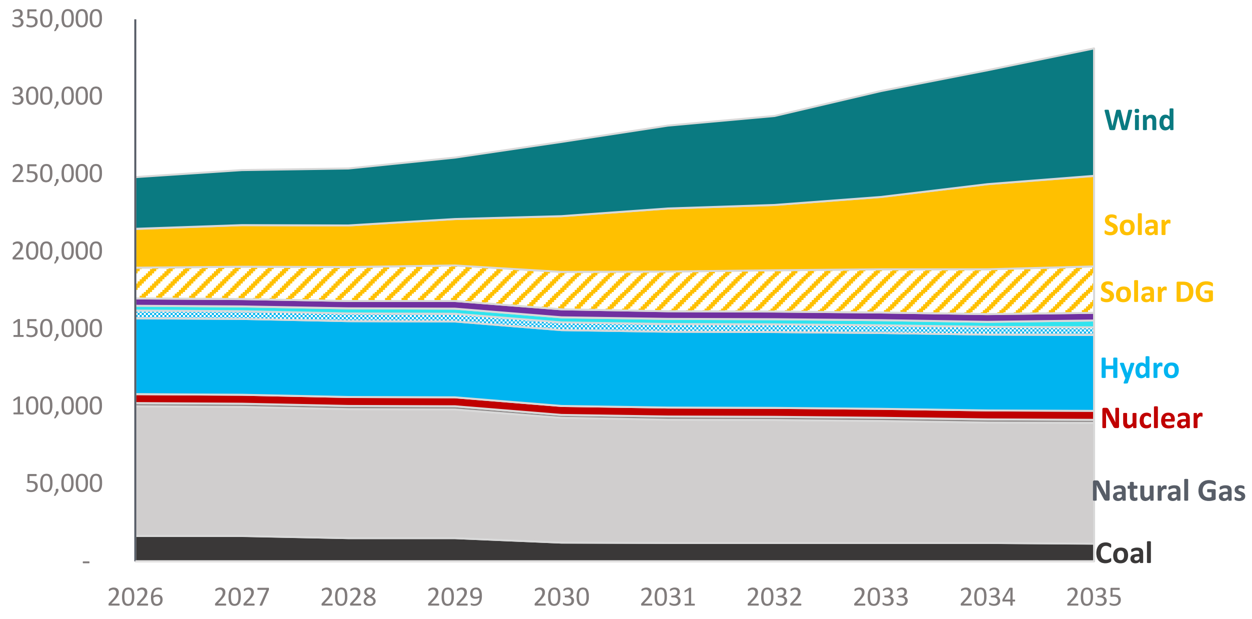
One of the primary goals for the Baseline Case was to estimate the evolution of the West's resource mix given the suite of assumed state policies. What follows is a summary of the most important resource expansion-related results from the Baseline Case study, which spanned 2026-2035.

By 2035, non-emitting resources provide 72% of generation capacity

The Baseline Case resource portfolio resulting from the capacity expansion portion of the study is presented below, in **Figure 18**. The portfolio includes existing generators, planned generation, and generation added via capacity expansion additions. It also reflects generator retirements.

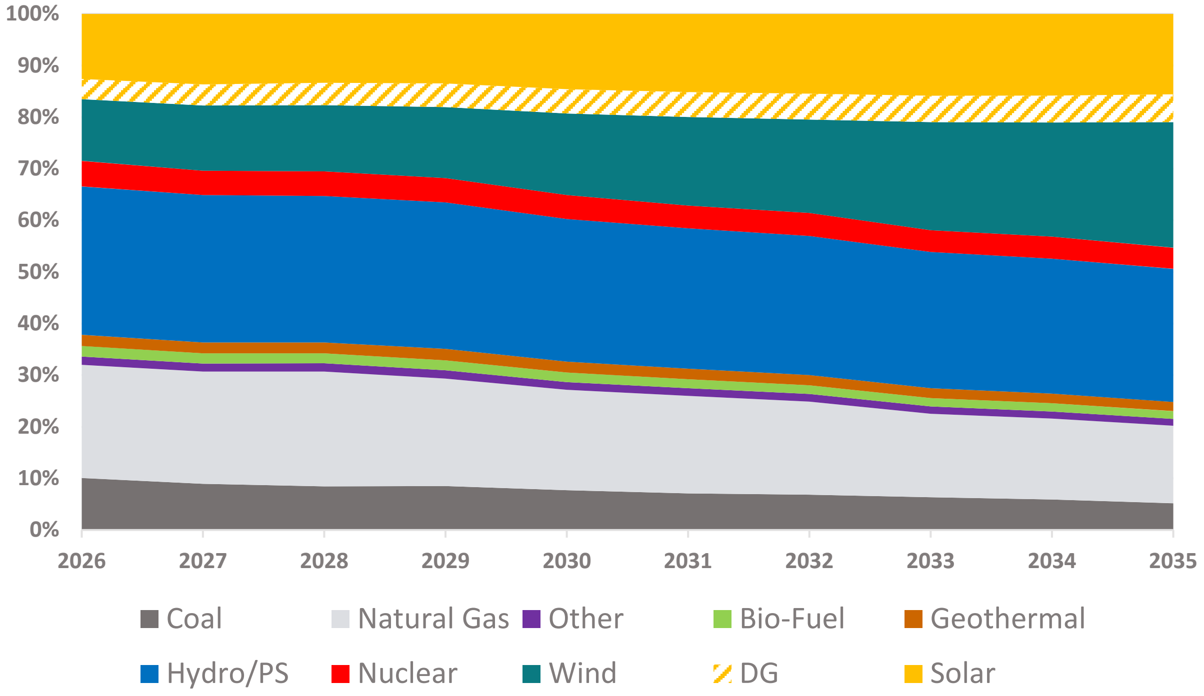
The expansion plan, which estimates resources required to meet modeled policy targets, capacity needs, and energy requirements, suggests that by 2035, zero-emission resources – including wind, solar, geothermal, hydro, and nuclear – will make up more than 72% of the West's generation capacity. Natural gas capacity is a significant portion of the fleet (~25%) throughout the study period, but coal is nearly eliminated, making up only 4% of installed capacity by 2035 (recognizing the substantial reduction in coal capacity that is already expected to occur between now and the beginning of the study period). Energy storage was a new resource option in the capacity expansion model but, because of the complicated revenue streams required to support the economics of storage, the model did not select energy storage in the Baseline Case expansion plan. To account for this, storage was considered in a scenario study addressed later in the report.

Figure 18: Western States Cumulative Generation Capacity (MW), Baseline Case



The preceding summary of the generation fleet for Western states presents capacity and does not address energy production. **Figure 19** summarizes the *energy* mix for the West. In the Baseline Case, wind and solar make up an increasingly large proportion of the Western system's energy mix during the study period. In 2026, wind and solar make up roughly 30% of the fuel mix. Gas and hydro are the two other largest sources of power in that timeframe. However, by 2035, due to the large build-out of wind and solar described above, wind and solar provide more than 40% of the system's energy needs. Hydro output does not materially change by 2035, so dispatchable resources, mainly coal and gas, are offset by the increasing renewable penetration. This dynamic – renewables offsetting dispatchable thermal resources – is observed across the West and is not unique to a given region. By 2035, the capacity expansion study for the Baseline Case results in zero-emission generation contributing nearly 80% of the system's energy needs.[19] The penetration of zero-emission generation exceeds the assumed "clean energy target" discussed elsewhere in the report because it includes all nuclear and large hydro, regardless if such resources qualify for policy targets in a given state.

Figure 19: Annual Energy by Type (%) for Baseline Case



Wind and solar additions from 2025 to 2035 total nearly 9 GW per year

The most striking change in the resource mix across the study period is the magnitude of wind and solar additions, which are driven by the public policy requirements represented in the Baseline Case and which the model selected over other available renewable technologies. Focusing on this increase in wind and solar, their cumulative installed capacity from 2005 through the end of the study period (2035) is shown in **Figure 20**. From 2005 through 2025

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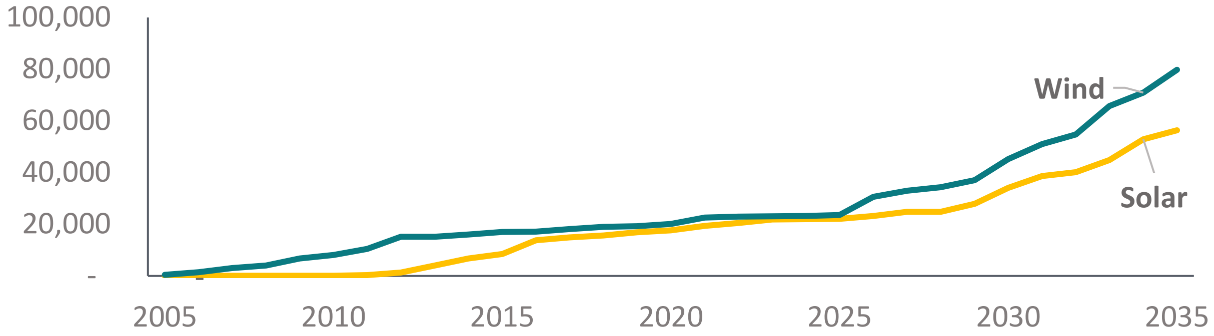
[19] The capacity expansion modeling utilized zonal topology and inter-regional links to represent the transmission constraints limiting the delivery of energy throughout the system. The production cost modeling's nodal topology introduced more granular transmission constraints which provided more operationally realistic delivery of renewable energy discussed later in this report. For this reason, these results, while based on detailed simulations, capture fewer flexibility constraints.

cumulative wind and solar additions totaled roughly 45 GW.[20] During the subsequent 10-year study period, Baseline Case modeling selected an incremental 90 GW of wind and solar generation.

Figure 20: Cumulative New Wind and Solar Additions in Western U.S. Since 2005



By 2035, the Baseline Case nearly eliminates coal from the generation fleet, but gas continues to provide significant capacity (although its energy output is limited)

The Baseline Case capital expansion modeling results in major changes to the thermal generation fleet. Results summarizing coal and gas capacity in the West are in **Figure 21**. The chart covers the 10-year study period. Today, the Western coal fleet represents roughly 34 GW of capacity. Due to planned and anticipated coal retirements, by the end of 2025, 64% of this capacity is still operational (21.7 GW). Coal resources make up 7% of total system capacity by the end of 2026, falling to 4% by the end of 2035. By the end of 2035, the study forecasts that less than 17 GW of coal will remain on the system. This decline is mostly due to announced retirements that take effect before 2034. The Baseline Case also forecasts a small number of accelerated coal retirements (~580 MW) identified as economical in the modeling.[21]

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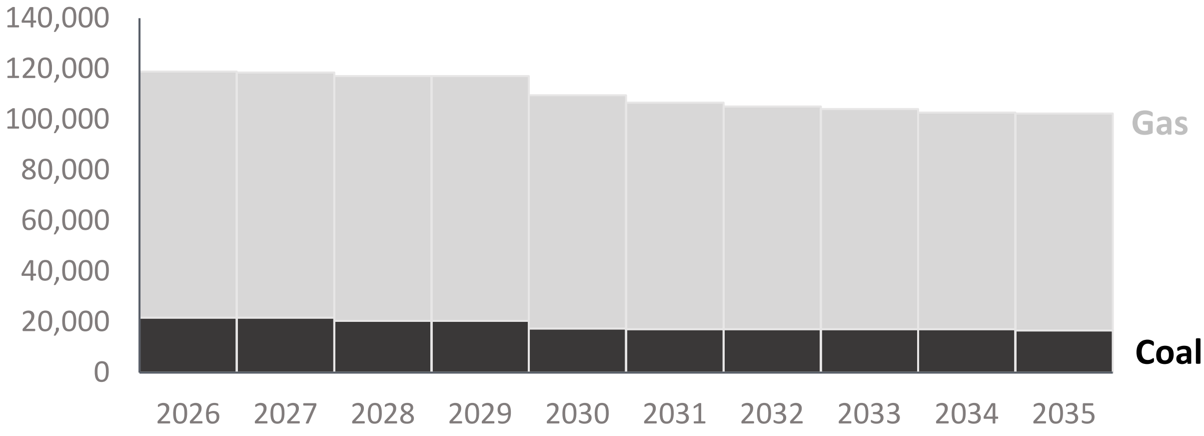
[20] Resource additions through 2025 are based on forecasts used to develop the Baseline Case.

[21] These economic retirements represent instances where coal units are retired through modeling optimization before their planned retirement date. The logic used in the modeling allows the advancement of retirement dates, but no delays beyond this planned date. The logic is similar for gas-fired resources. Economic retirements were made without considering the cost of decommissioning and are not equivalent to regulatory-grade, unit-level retirement evaluations.

The expansion modeling of the Baseline Case also captured changes to the gas fleet, again shown in **Figure 21** for the Baseline Case. The study reflects material gas retirements during the study period, mostly in California (consistent with the CPUC IRP Preferred Portfolio assumed in the study). However, West-wide, the total amount of gas capacity remains relatively consistent through the study period. Today there are roughly 100 GW of gas-fired resources on Western Interconnection. By the end of the study period, gas totals 86 GW of installed capacity, a reduction of 14% from today's levels. There were 5,500 MW of gas additions during the study period that offset some of the gas retirements.

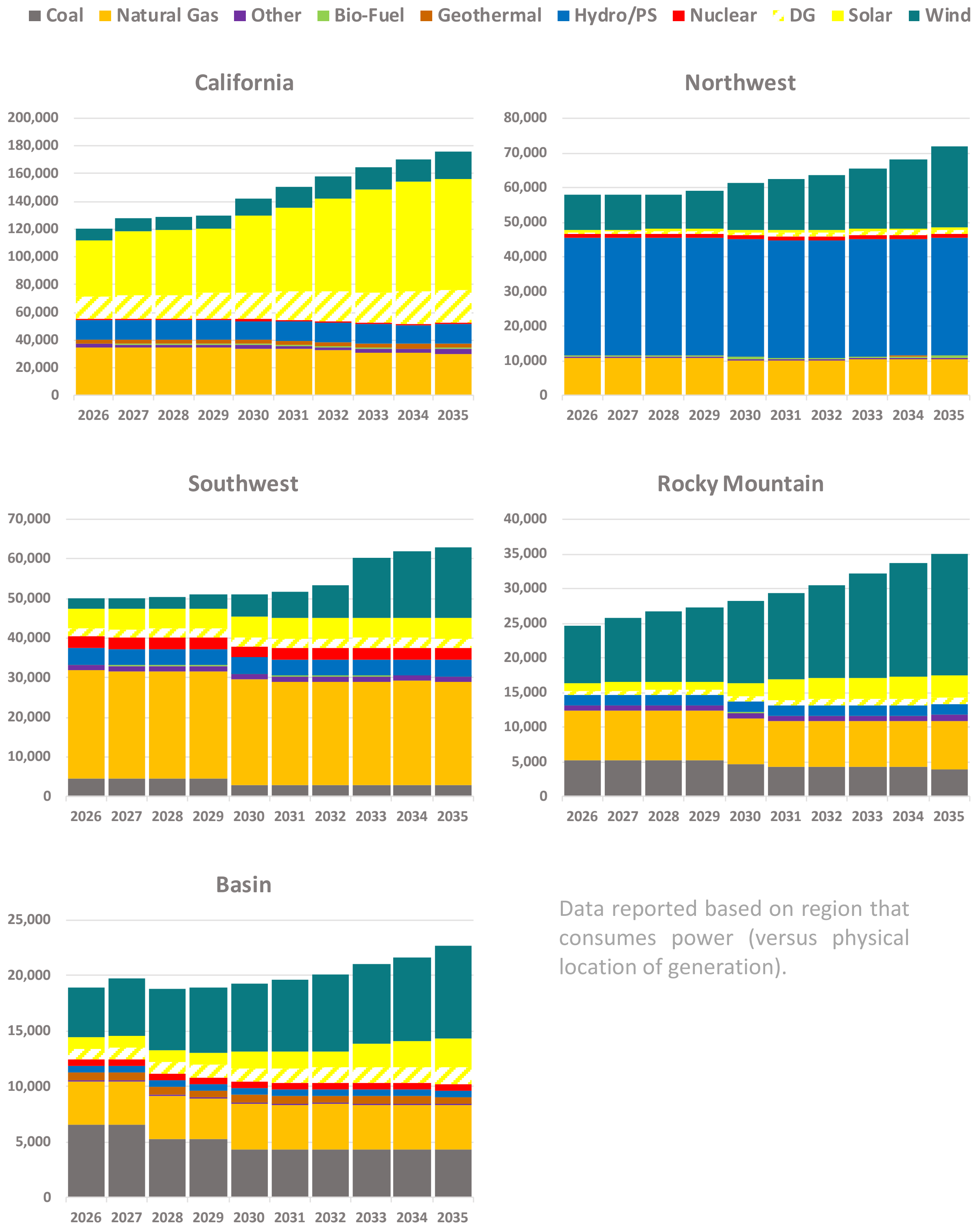
Figure 21: Gas and Coal Capacity During Study Period (MW)



Significant resource diversity forecasted for all regions by the end of the study period

We performed capacity expansion modeling for the entire system but resulting portfolios are presented regionally. **Figure 22** summarizes the resource mix, on a capacity basis, for each region during the study period. The portfolios in 2026, 2030, and 2035, as shown below, were inputs into other models used to evaluate the Baseline Case.

Figure 22. Cumulative Generation Capacity (MW) in Baseline Case, by Region in Which it is Consumed



Data reported based on region that consumes power (versus physical location of generation).

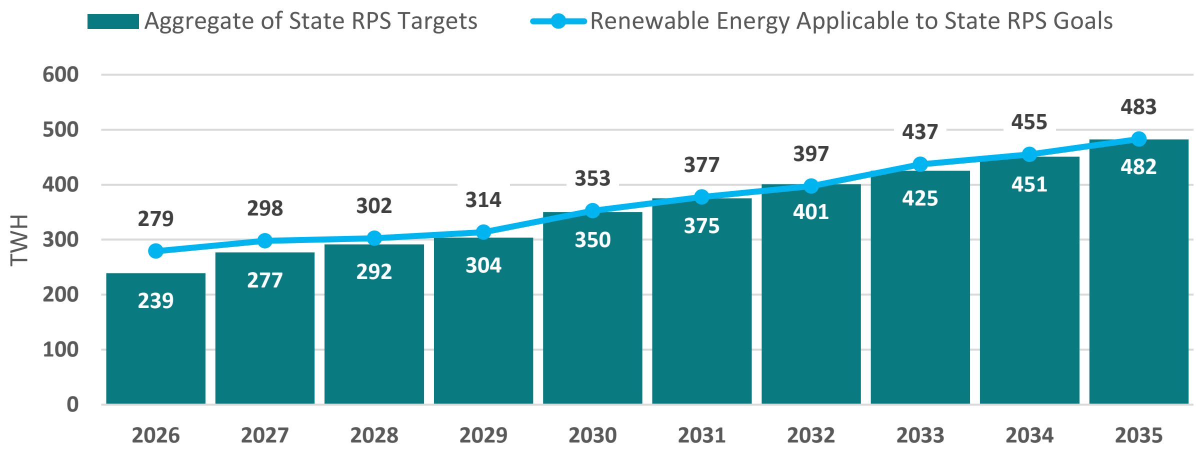
Resource additions in the Baseline Case do not surpass technical potential limits considered in the study

Based on the Baseline Case results, the West will likely require a significant renewable build-out to meet policy goals through the 2035 timeframe. The most significant resource additions are likely to take place in California, the Northwest, and the Southwest. While the magnitude of renewable deployment is significant, it did not exceed state-level technology-specific technical potential limits sourced from NREL. Outside of new wind in California (which was assumed to have an incremental development potential of 5 GW), there were no instances in which resource additions were constrained due to technical potential limits. The assumed technical potential limits capture land-use effects, resource quality, and other factors.

Policy goals and subsequent resource additions modeled in the Baseline Case cause West-wide carbon emissions to fall to 67% below 1990 levels by 2035

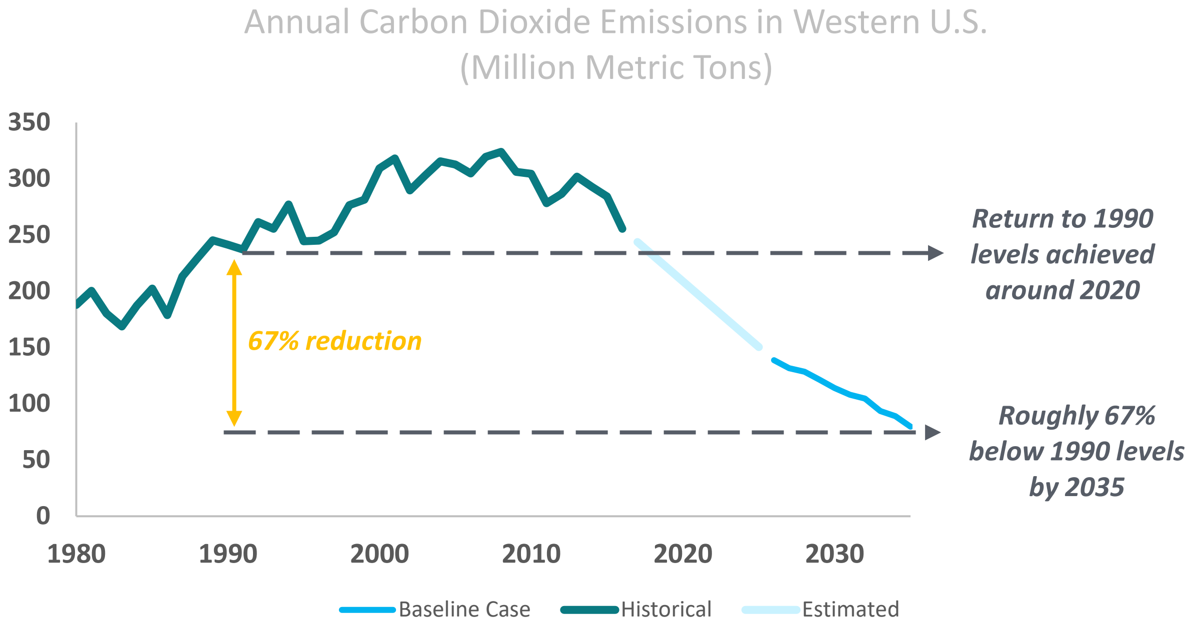
We modeled Baseline Case policy constraints on a state-specific basis. The capacity expansion modeling produced a resource build-out that indicates sufficient renewable generation can be added to achieve these policies, shown in **Figure 23**. Resources allowed to contribute to these policy goals included wind, solar, bio-fuel, and geothermal power throughout the system as well as nuclear and hydro power serving Washington and Arizona.

Figure 23. Aggregated Baseline Case Clean Energy Target Compared with Renewable Energy in Baseline Case



Resource portfolios were built out to certain RPS percentages, and the modeling assumed a coordinated cap-and-trade program was in place for California, Oregon, and Washington. One of the consequences of these assumptions was renewable resources frequently displace thermal generation. This displacement, coupled with the carbon price (in certain states), caused carbon emissions to fall during the study period. By 2020, Western-state emissions are forecasted (on a straight-line basis) to return to 1990 levels and by 2035, Western-state electric sector emissions were 67% below 1990 levels, as shown in **Figure 24** (which also includes historical Western-state emission data, for reference).

Figure 24. Western State CO_2 Emissions from Electric Sector: Historically and Study Period



5.2 Resource Adequacy in the Northwest

In order to evaluate the flexibility implications of the Baseline Case resource portfolio identified in Section 5.1, the study includes an adequacy study designed to ensure that the Northwest system, specifically, has sufficient capacity resources in the Baseline Case portfolio such that any potential flexibility needs of in the region will not be exaggerated on account of pure capacity shortfalls. If a given system is short on system capacity, its flexibility challenges will be overstated.

Another motive in performing detailed adequacy analysis of the resulting Baseline Case resource portfolios was that certain study sponsors had specific interest in Northwest adequacy. Areas of interest to included:

- The nature of the Northwest capacity challenges as the region moves forward in meeting policy objectives;
- The amount of new gas-fired generation that might be necessary assuming the region adds resources for policy purposes; and
- The effectiveness of energy storage and demand-side options to defer or avoid the need to construct thermal resources in the Northwest.

> ***The Baseline Case resource portfolio evaluated in the adequacy study reflected announced and anticipated coal retirements, planned resource additions (from utility IRPs), and new resources added during the study period based on capacity expansion modeling***

A summary of the Baseline Case supply-side resources, for the Northwest region, is summarized below in **Table 11**. The portfolios for 2027, 2030, and 2035 consider generator retirements, resource additions based on IRPs, and additions added based on the capacity expansion analysis performed with AURORA. The capacity expansion analysis added renewable resources consistent with policy targets in the Northwest, along with capacity resources (gas) required to meet the *simplified* capacity metrics used to evaluate reliability in the capacity expansion modeling. Although the region is losing thermal capacity due to coal retirements, it also added significant amounts of wind and solar to meet policy objectives.

Table 11: Resources for Northwest Region (net MW installed capacity)

Type	Capacity (MW)			
	2019	2027	2030	2035
Coal	4,441	107	107	107
Natural Gas	9,290	10,664	10,167	10,564
Other	152	380	380	380
Bio-Fuel	741	557	557	557
Geothermal	41	41	41	41
Hydro/PS	33,987	33,744	33,744	33,744
Nuclear	1,200	1,200	1,200	1,200
DG	109	574	818	1,323
Solar	428	694	694	694
Wind	7,706	9,967	13,451	23,355
TOTAL	**58,095**	**57,928**	**61,159**	**71,966**

The coal retirement assumptions are summarized below in **Table 12**. Coal retirements assumed by 2030 total 4.4 GW of capacity, and those occurring before the 2027 study year total 3.3 GW. In addition, the capacity expansion modeling selected 1.5 GW of gas retirements in the region.

Table 12: Assumed Coal Retirements in NW Region

Name	Nameplate Capacity (MW)	NWPCC Rate-Based Capacity (MW)	Assumed Retirement Year
North Valmy 1	277	127	2019
Boardman	642	522	2020
Colstrip 1-2	716	308	2022
Colstrip 3-4	1,647	1,199	2024
Centralia 1	730	670	2021
Centralia 2	730	670	2025
North Valmy 2	290	134	2025
Jim Bridger 1	608	530	2027
Jim Bridger 2	617	530	2029
Total:	**6,257**	**4,690**	

Much of the incremental capacity value provided by new renewable resources required for policy purposes was supplied by new Montana wind resources, which were available and selected in the capacity expansion modeling without additional transmission build-out because the study assumed retirements for Colstrip units 3 and 4 by the end of 2025 (which freed up significant amounts of transmission).[22]

In addition to the resource supply summarized above, the adequacy study performed using GENESYS also represented supply available to the region in the form of:

- Demand response (DR) – NWPCC's existing & projected DR through 2024:
    - Winter: 180 MW max response; 7,200 MWh max energy/year; 4-hr response
    - Summer: 630 MW max response; 25,200 MWh max energy/year; 4-hr response
- Spot market purchases – up to 2,500 MW of 17,000 Btu/kWh thermal available in all hours of the winter months.
- Southwest off-peak purchase day-head, weekly, or monthly market imports – up to 3,000 MW for each of the purchase ahead timeframes and each represented as 12,100 Btu/kWh thermal available in all off-peak hours: 10pm-6am Monday-Saturday and all of Sunday.
- Standby resources – resources which provide unique applications towards resource adequacy needs. Their contributions are applied with a post-processor to "patch" adequacy needs that show up during the GENESYS simulation. **Figure 25** summarizes the standby resource assumptions, which were slated for the NWPCC 2024 Resource Adequacy Assessment.

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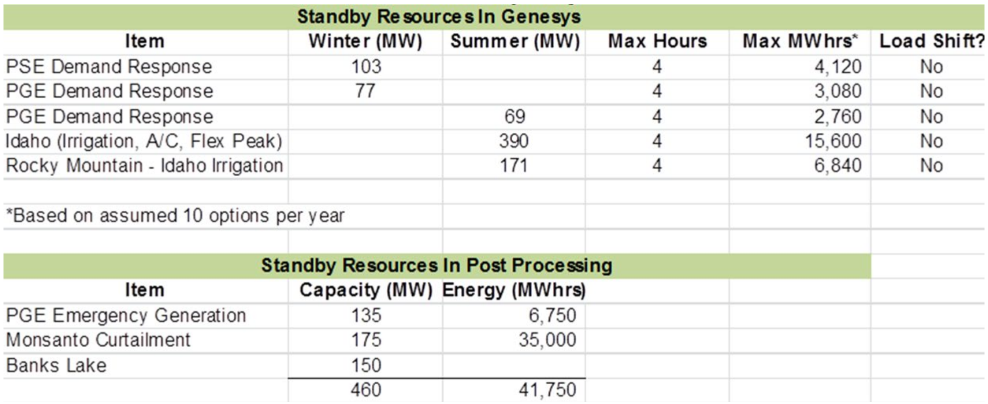
[22] This study assumed that Colstrip Units 3 & 4 would retire by the end of 2025 on the basis that, after this date, Washington utilities are no longer allowed to include coal generation in rate bases. There is the potential that Colstrip 3 & 4 are retained for additional years, perhaps serving non-Washington loads. However, this study wanted to investigate potential uses of the Montana to Northwest transmission, so the units were assumed to be retired. Since this decision has not been made by the plant's owners, we acknowledge that area is ripe for sensitivity study.

Figure 25. Standby Resources slated for the NWPCC 2024 Resource Adequacy Assessment[23]



Standby Resources In Genesys

Item	Winter (MW)	Summer (MW)	Max Hours	Max MWhrs*	Load Shift?
PSE Demand Response	103		4	4,120	No
PGE Demand Response	77		4	3,080	No
PGE Demand Response		69	4	2,760	No
Idaho (Irrigation, A/C, Flex Peak)		390	4	15,600	No
Rocky Mountain - Idaho Irrigation		171	4	6,840	No

*Based on assumed 10 options per year

Standby Resources In Post Processing

Item	Capacity (MW)	Energy (MWhrs)
PGE Emergency Generation	135	6,750
Monsanto Curtailment	175	35,000
Banks Lake	150	
	460	41,750

Finally, the Baseline Case modeling in GENESYS also incorporated contracts between the U.S. and Canada based on the BPA 2018 White Book.[24]

The Baseline assumed load growth levels consistent with the NWPCC 7th Power Plan

Key demand-side assumptions used to perform the study are presented below in **Table 13.**

Table 13: Key Inputs into Adequacy Analysis

Demand-Side Assumption	2027	2030	2035	CAGR (%)
Peak Net Load (MW)	**30,754**	**31,064**	**32,401**	**0.58%**
Peak Demand	34,677	35,210	36,212	0.48%
Energy efficiency (EE) adjustment	4,725	5,207	5,203	1.08%
Electric vehicle (EV) load adjustment	802	1,061	1,392	6.32%
Distributed generation (DG) adjustment	0	0	0	--
Net Load Energy (aMW)	**20,030**	**20,113**	**21,067**	**0.56%**
Demand Energy	23,021	23,326	24,016	0.47%
Energy efficiency (EE) adjustment	3,277	3,569	3,345	0.23%
Electric vehicle (EV) load adjustment	394	509	644	5.62%
Distributed generation (DG) adjustment	107	153	248	9.78%

The NWPCC produces several load forecasts that it uses for varying purposes. This study used the 7th Power Plan net-of-conservation energy forecast because it accounts for the long-term

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[23] NWPCC Resource Adequacy Assessment Committee (RAAC) Meeting, February 27, 2019: https://nwcouncil.app.box.com/s/1nxbyc9xeed5d4nz8ih8hmkuaugqoedx

[24] The BPA 2018 White Book only had data up to operating year 2029, so the 2029 assumptions were carried through the 2030 and 2035 study years. BPA staff provided this information.

effects of energy efficiency, while also having the benefit of extending for the length of our study period, which allowed us to avoid extrapolating shorter-term forecasts (which could lead to over- or under-estimating long-range demand growth). The 7th Power Plan peak demand forecast was adjusted for use in the GENESYS model by adding in hourly representation and temperature-based variability roughly consistent with the variability in recent NWPCC adequacy assessments.

As we address later in the report, the NWPCC's shorter-term load forecasts, such as those used to conduct near-term adequacy studies, are developed using entirely different processes and methods. Using the NWPCC's short-term load forecasts significantly impacts the adequacy analysis.

Assuming no new incremental resources and the 7th Plan load forecast, the Northwest region has a significant capacity need that occurs no later than 2030

If we assume that *none* of the new resources in the Baseline Case portfolio are constructed, and that loads materialize consistent with the 7th Plan, then GENESYS results indicate the region has a capacity need of 900 MW of by 2030 and 2,080 MW by 2035. This future *does* assume 681 MW nameplate of storage, wind, and solar resources from Northwest utility IRPs that are planned to be in-service before 2027. If we excluded these resources from the portfolios, the capacity need is larger and occurs sooner than what is reported here. **Table 14** shows the Resource Adequacy results for these futures in which the Baseline Case expansion does not occur.

Table 14: Baseline Case Expansion Does Not Occur

Study Year	Baseline Case with No New Generation, but with IRP Plans		No New Generation Case (including No IRP Generation)	
	% LOLP	Incremental Capacity Need (MW)	% LOLP	Incremental Capacity Need (MW)
2027	0%	0	2.7%	0
2030	13.3%	881	16.6%	1,109
2035	38.8%	2,080	43.5%	2,414
Adequacy Target	5%	0	5%	0

Study results indicate that the Baseline Case includes sufficient capacity to maintain Northwest reliability through 2035

The Baseline portfolio – which netted nearly 17 GW of renewable additions, 3.2 GW of gas additions, and 5.9 GW of thermal retirements, all by 2035, in the Northwest region – provides capacity sufficient to ensure adequacy in the Northwest region. This portfolio includes resources sufficient to meet public policy needs and also includes new gas added by the capacity expansion model for adequacy purposes. **Table 14** shows the LOLP of the three study years is lower than the 5% adequacy threshold for the region, which indicates the portfolio contains sufficient capacity to meet the assumed reliability target for the region. This analysis was based on the 7th Plan load forecast.

Table 15: Baseline Case Expansion Does Occur

Study Year	% LOLP	Incremental Capacity Need (MW)
2027	0.3%	0
2030	0.9%	0
2035	0.9%	0
Adequacy Target	5%	0

As shown in **Table 16,** if we assume that the region does not construct any new gas during the study period, but the rest of the Baseline Case portfolio is built-out, the system has a 500 MW capacity need in 2030 and a 1,500 MW capacity need in 2035.

Table 16: Baseline Case Expansion with no New Gas

Study Year	% LOLP	Incremental Capacity Need (MW)
2027	1.2%	0
2030	8.1%	500
2035	23.4%	1,500
Adequacy Target	5%	0

The results in the study cases above are a direct product of their input assumptions. The cases described above assume the same levels of:

- Demand and energy efficiency (including EV-driven loads), with demand based on 7th Plan forecasts
- Distributed generation
- Demand response (which is based on the NWPCC 2024 Adequacy Assessment)
- Availability of spot market purchases
- Availability of off-peak Southwest imports
- Thermal retirements that take place prior to the study period

The Baseline Case's assumption that a coordinated energy market materializes did not impact the modeling assumptions used in this adequacy assessment.

When load loss events do occur in these study cases, they are for extended periods

As the system relies on increasing amounts of weather-dependent resources (including hydro, wind, and solar), extended low solar or wind conditions that occur simultaneously with low hydro availability can cause capacity shortfalls that last for extended periods. Even for the scenarios that do meet the 5% LOLP adequacy standard *on an annual basis*, there are capacity shortage events that have extended durations.

Table 17. Average Duration (HR) / Size (GW) of Loss-of-load Events

Study Year	Baseline Case	Baseline Case w/o New Gas	No New Generation Case
2027	25 / 36	17 / 25	16 / 23
2030	14 / 23	11 / 11	10 / 10
2035	17 / 29	10 / 13	10 / 10

> ***Based on the assumptions used to perform this study, even if public policy needs in the region are met, a minimum of 1.5 GW of firm capacity is still needed to ensure reliability by 2035***

A scenario that removes new gas additions from the Baseline Case was run because the Baseline Case, developed using the capacity expansion tool, exceeded regional adequacy standards for all study years. For this reason, the Baseline Case was not useful in identifying the minimum amount of firm capacity required to maintain reliability in the Northwest. The case with no new gas, which is still policy-compliant from a renewable/clean resource perspective, was capacity deficient starting in 2030. This means that, assuming the region relies on the resource portfolio from the Baseline Case (which includes Montana wind), the region must add firm capacity of 460 MW in 2030 and 1.5 GW by 2035 to maintain reliability. New gas, in these amounts, is sufficient to meet the needs of the system based on this analysis. There are also other options that, based on this study, appear to meet the needs of the region. Again, these results are sensitive to load forecast assumptions.

> ***Based on the results of this study, remaining long-term capacity needs for the Northwest system, after accounting for capacity supplied by policy-driven resources, can be met with: gas, long-duration storage, or increased access to market purchases.***

As described previously, when we removed the new gas generation in the Baseline Case, the system had a minimum capacity need of about 460 MW in 2030 and 1,500 MW in 2035. **Table 18** shows the 460 MW and 1,500 MW of gas generation required for the Baseline Case to meet the adequacy standard. The table also shows the nameplate MW of other resource options needed to meet this same reliability metric. Said differently, the nameplate capacity of the other resources provides the same capacity value of the gas resource.

Table 18: Nameplate Capacity Required to Address Baseline Case Capacity Shortages When Only Policy-Driven Resources are Built

Fill Capacity Gap with….	2030	2035
New gas	460	1,500
Incremental solar	1,300	>6,000
Long-duration storage (12 – hr)	500	2,200
Increased southwest market purchases[25]	500 all year	900 winter 1,800 summer
Demand response	500 MW, 2,725 MWh	1650 MW, 24,700 MWh

Based on the study results, new solar can address the capacity issue in 2030, but the 6 GW of hypothetical additions required in 2035 reflect the diminishing capacity value of solar as the size of the capacity shortage increases, which indicates that solar may not be an efficient option to address long-term adequacy issues in the Northwest.

Long-duration storage is effective in both study years. In 2030, it has a capacity value of 92%, and in 2035 it has a 68% capacity value. It is not as effective as gas, on a per-MW basis, but 12-hour storage does appear to provide enough energy to address a large number of reliability events.

Finally, greater reliance on market purchases from southwest markets is another tool that appears to be effective in addressing the capacity gap during both study periods.

Short-duration (4-hr) storage cannot be relied on as an alternative to meet the region’s adequacy needs because of the extended duration of adequacy events, which start in 2030 and increase in severity by 2035. It has a capacity value of only 11%.

Montana wind was an effective capacity resource for the Northwest with a 40% capacity value, but transmission availability for new additions of Montana wind (beyond what is already in the Baseline Case) may be limited unless upgrades are constructed. Wind in the Columbia Gorge has a relatively low capacity value (8%), which means the required nameplate installations to

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[25] The values here are incremental to what is already assumed in the study.

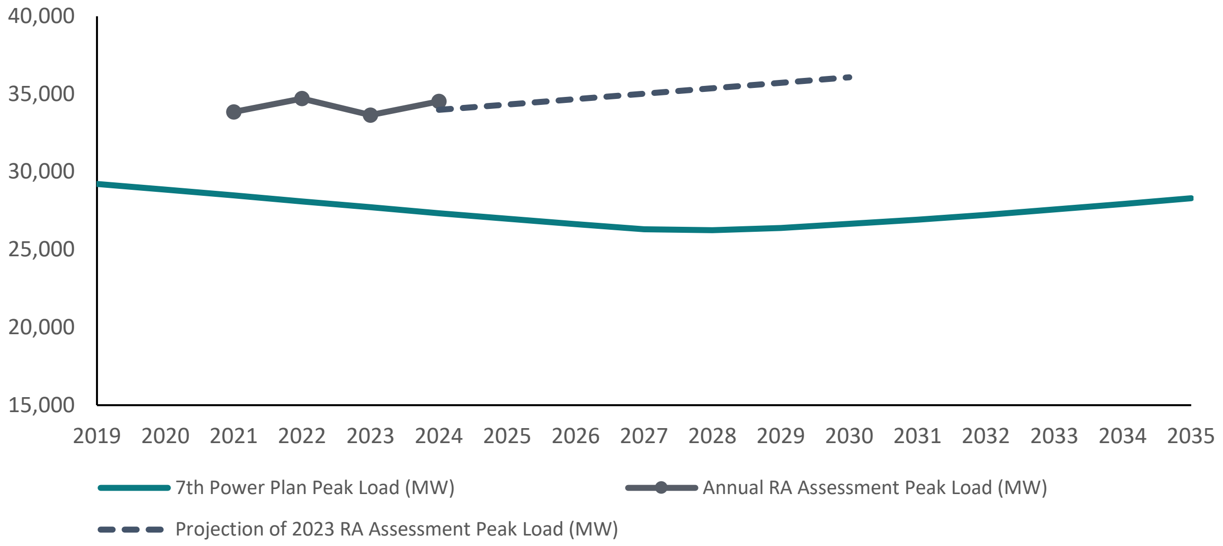
achieve the reliability metrics might approach 15,000 MW by 2035, making this option comparatively inefficient.

Demand response also has a very low capacity value at 14%. Because it is generally a short-duration resource – no more than a few hours – it is not effective for resolving the longer-duration challenges that appear in this study.

The results of this study were sensitive to the load forecast assumption

This study relied on the 7th Power Plan for a forecast of Northwest demand. Recent short-term Resource Adequacy Assessment studies performed by the NPWCC indicate comparatively higher load levels in the near-term. **Figure 26** summarizes these two peak demand forecasts. Since the 7th Power Plan forecast extends more than 20 years, we opted for this data source as it suits the long-term nature of operational portion of this study and also allowed for consistent load forecasts in all study areas. Furthermore, we had concerns about extrapolating near-term forecasts for 10 years or longer, especially given this study's focus on operational analysis.

Figure 26: Comparison of NWPCC Load Forecasts



The NWPCC is the appropriate authority on their load forecasts, which are fundamental to analyzing the region's adequacy needs. When the NWPCC performs its short-term resource adequacy assessments, it uses econometric load forecasts. In comparison, the 7th Plan load forecast is developed via an end-use load forecast model. The short-term forecast and the long-term forecast generally do not converge in the mid-years (3-5 year out, as represented in the figure above). These load forecasting modeling challenges are well known by the NWPCC and are targeted for improvements.

Material benefits of using the long-term end-use load forecast (7th Plan) include:

- Better representation of the impact of future end-use codes and standards;
- Reflection of future conservation goals the region may achieve; and
- General appropriateness for long-term energy-based analyses (such as the operational studies herein).

Benefits of using the short-term adequacy assessment forecast include:

- Ability to reflect exogenous load drivers;
- Reflection of *achieved* conservation;
- Hourly forecast and representation of extreme weather events (although this study added hourly variability and extreme weather variability to the 7th Plan forecast for the purposes of this assessment, which helps to mitigate this factor);
- Appropriateness for short-term capacity-focused analyses.

Using load levels consistent with the trajectory of the NWPCC resource adequacy assessments, the capacity shortages contemplated in the passages above occur *sooner in time* and are *larger in size*. We demonstrated the impact of load assumptions through a sensitivity study we performed for the 2027 study year in which we assumed higher load levels (consistent with the trajectory of the short-term forecast, shown in the chart above) and re-ran the Baseline Case with and without new gas. Results for the sensitivity are summarized in **Table 19**.

Table 19. Sensitivity Study with Higher Loads – NW Adequacy Results

Study Year	Baseline Case High Load Sensitivity		Baseline Case w/ No New Gas High Load Sensitivity	
	% LOLP	Incremental Capacity Need (MW)	% LOLP	Incremental Capacity Need (MW)
2027	7%	785	32.6	2,838
Adequacy Target	5%	0	5%	0

This load sensitivity for 2027 assumes a peak demand for the Northwest region of 35,015 MW, which is 14% higher than the Northwest peak demand assumed in our default studies.[26] The Baseline Case, which includes 1.8 GW of new gas along with 3.6 GW of new wind and solar generation built by 2027, has a LOLP of 0.3% and, beyond those additions, does not have incremental capacity needs in 2027. However, in the high load sensitivity with the same resource portfolio, the Northwest needs 785 MW of *additional* firm capacity, beyond the capacity included in the Baseline, to meet the 5% LOLP adequacy target. If the new gas additions are removed from the Baseline Case and the higher load forecast is used, the system needs at least 2.8 GW of incremental firm capacity to meet the adequacy target in 2027.

This illustrates that the timing and magnitude of Northwest adequacy shortages are highly dependent on load forecast and assumed resource assumptions. Based on this higher load forecast, study results indicate that even if 3.6 GW of new wind and solar generation are built by 2027 (for public policy purposes), the Northwest region’s need for incremental firm capacity may still exceed 2.8 GW.

This work seeks to add to the regional dialog on this evolving issue

As stated previously, the primary purpose of this work was to ensure the flexibility portion of this study included appropriate capacity in the Northwest region. That goal was achieved and the resource portfolios were not adjusted on this basis. However, this does not mean that no new action is needed to address capacity needs in the region. The Baseline Case assumes that substantive investments are made in all types of generation between now and 2027, 2030, and 2035, including Montana wind and gas. Load sensitivity analyses indicate that even if these actions do come to pass, the region may require *additional capacity* above and beyond the level imbedded in the Baseline Case, depending on how much load materializes.

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[26] These peak demand values are the average peak demands of the 69 load shapes considered in the study. As such, simulated peak demands varied around these average values.

In the same vein, one of the assumptions that make this study different from some of the other Northwest resource adequacy studies, summarized in Section 3.4, is that it assumes the Northwest region and its utilities are taking incremental actions to meet state policy goals in the coming years. In addition to the planned closure of a portion of its thermal fleet, the Northwest is home to several major policy changes that will impact its resource mix. These policies will increase the amount of weather-dependent resources on the system – mainly in the form of new wind and solar. This leaves the Northwest region very reliant on hydro, wind, and solar availability. This reliance has implications for the region's adequacy and given this evolving resource mix, and based on the highly sensitive nature of our study results for variables such as load forecasts and resource additions, the region should continue to evaluate these developing issues and begin work evaluating the cost-effectiveness of available supply options. This study suggests that, depending on the nature of the capacity shortage, there may be a number of viable supply options. It also emphasizes the importance in investing in the development of long-term adequacy-focused load forecasts.

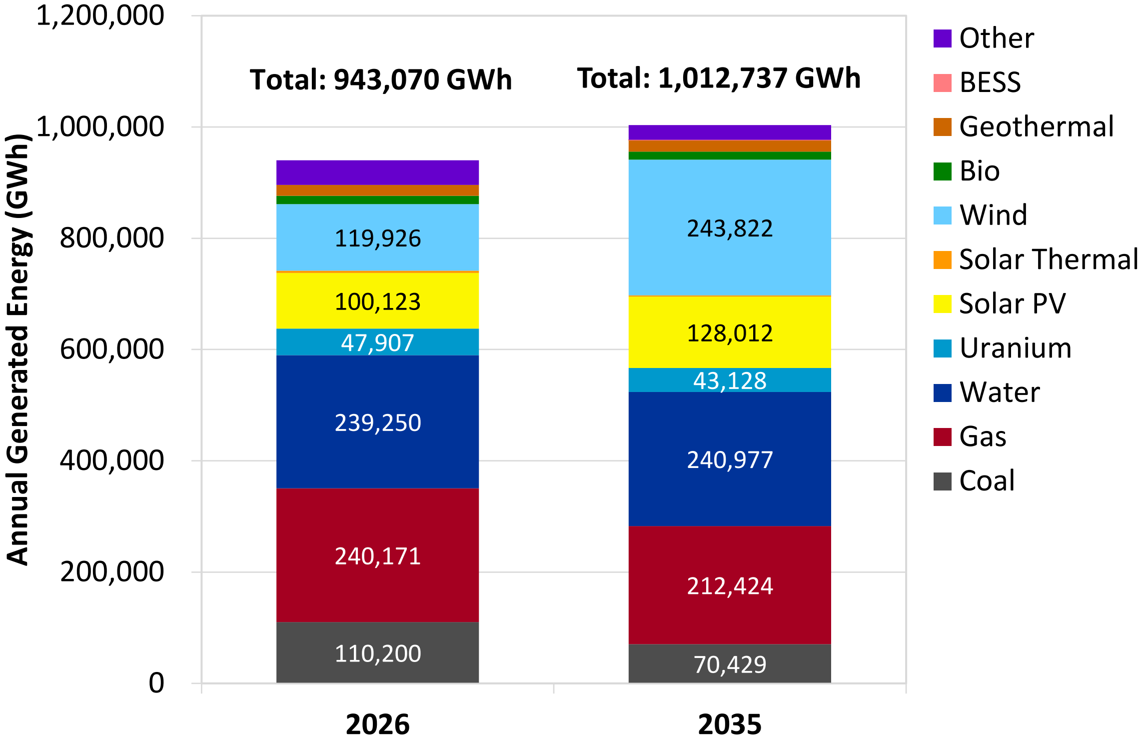
5.3 Operational Performance

The Baseline Case portfolios derived through capacity expansion modeling, which are presented in Section 5.1, were also studied for their operational performance using production cost modeling. The portfolios, which evolve over the 10-year study period, represent a resource mix that, on an energy basis, is able to comply with state policies across the West so long as system inflexibility (e.g., curtailment) does not prevent it from doing so. The operational performance of the portfolios was evaluated using security-constrained economic dispatch modeling for years 2026 and 2035, bookending the study period. We provide details surrounding the study approach in Section 2.0. The following materials in this section summarize the key results from the analysis.

The Baseline Case was evaluated for operational performance in 2026 and 2035, using resource portfolios commensurate with policy needs in those study years

Figure 27 summarizes generation mixes for the Baseline Case in the two study periods. These resource portfolios were designed to target a Western-state clean energy target of 33% in 2026 and 64% by 2035. These policy targets were estimated based on the assumed state policies described in Section 4.3. Resource portfolios designed to meet these targets were developed through the capacity expansion modeling and then were input into the security-constrained dispatch model to perform this study.

Figure 27: Delivered Energy for 2026 and 2035 Baseline Cases



West-wide curtailments for the Baseline Case in 2026 are less than 4% of total renewable generation, but curtailments increase drastically by 2035 due to a lack of system flexibility

As previously discussed, this study uses the renewable curtailment metric as an indicator of system flexibility. In the 2026 Baseline Case, after accounting for 3% system-wide renewable curtailment, delivered energy qualifying towards our clean energy target met 36% of Western energy needs. Based on this result, the amount of clean power delivered to loads was more than sufficient to meet the policy goals modeled in the study.[27]

The 2035 Baseline Case was not successful in achieving estimated policy targets because curtailments prevented needed clean energy from being delivered. By 2035 in the Baseline case, renewable curtailments reached 20% of total clean energy generation, and as a result, the system had just 52% clean energy penetration (delivered), which was less than the 64% clean energy target based on assumed policy mandates. We report regional and west-wide renewable penetrations and curtailments in **Table 20**, along with the estimated clean energy target for the system**.**

Table 20: Baseline Case Curtailment and Clean Energy Penetration

Regional load served by clean energy[28]	**2026**		**2035**	
	Curtailment (%)	**Penetration (%)**	**Curtailment (%)**	**Penetration (%)**
Basin	0%	14%	15%	32%
California	3%	49%	25%	56%
Northwest	1%	26%	12%	60%
Rocky Mountain	5%	35%	26%	65%
Southwest	2%	34%	18%	36%
Western U.S.	**3%**	**36%**	**20%**	**52%**
	Clean energy target: 33%		**Clean energy target: 64%**	

These regional and system-level curtailment results indicate that the system has, or will have, sufficient system flexibility necessary to achieve policy targets through the mid-2020s. Said

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[27] This analysis was not intended to serve as a detailed RPS compliance analysis. Hydro energy in California was not counted as renewable energy, but it is acknowledged that certain small hydro does contribute to CA RPS. The analysis did not utilize renewable energy certificate (REC) multipliers specific to certain resources or REC banking, both of which would have been necessary to perform an in-depth calculation of some states' RPS-related renewable energy.

[28] Renewable energy in the model served both local and remote load and this table reports the renewable energy based on the location of the load its serving. For example, Southwest solar remotely serving California load is reported as California renewable energy in this table.

differently, the Baseline Case portfolio modeled for 2026, including its transmission capability, generation retirements, thermal capacity, renewable portfolio, and demand-side representation, along with other assumptions, together appear to have embedded flexibility sufficient to integrate renewable penetrations consistent with near-term policy targets. While these results do assume a highly coordinated power market, they suggest that there are no obvious technical barriers to achieving recently enacted public policies mandating higher renewable penetrations in the mid-term. However, there are technical challenges in achieving the increasingly stringent targets in the 2030s.

The 2035 Baseline Case portfolio which, technically, has sufficient energy content to meet policy targets and assumes coordinated power trade across the West, did not have sufficient flexibility to meet the assumed 2035 policy targets. The 2035 system likely does not have enough flexible resources, such as transmission, demand-side participation, resource diversity, flexible operation of renewable and thermals, and other flexibility enhancing strategies, imbedded into our Baseline Case forecasts. We discuss the barriers preventing the 2035 portfolio from achieving policy targets in the subsequent sections.

A lack of buyers for excess renewable power is partially to blame for the flexibility challenges apparent in the 2035 Baseline Case

This study assumes that by 2035, most Western states are moving toward deep penetrations of renewables. When only one or two states are seeking to achieve ambitious policy goals, states can manage (and utilize) excess renewable output simply by exporting overgeneration to other neighboring states via the transmission grid. The power finds a home, and the environmental attributes are retained. As demonstrated in the series of weekly operational charts in **Figure 28**, the 2026 Baseline Case relies heavily on exports to mitigate system inflexibility. In this example, California, which has a significantly higher renewable penetration than neighboring regions in 2026, avoids curtailing excess renewable generation output during mid-day solar production periods by exporting excess generation to neighboring regions that would otherwise need to dispatch local thermal resources, such as gas-fired combined cycles, to meet their loads. In the image below, we represent excess production in California as the generation area *above* the dark line (which is load), and in the Southwest, we represent imports into the region (largely from California) as the gap between its load and its in-region generation total. The temporal coincidence between the California overgeneration and the backing down of thermal generation in the Southwest is obvious. This example, spanning a spring week in 2026, demonstrates the value of using the transmission system to export excess power to avoid renewable curtailment.

Figure 28: 2026 Operations in Southwest and California - Late April

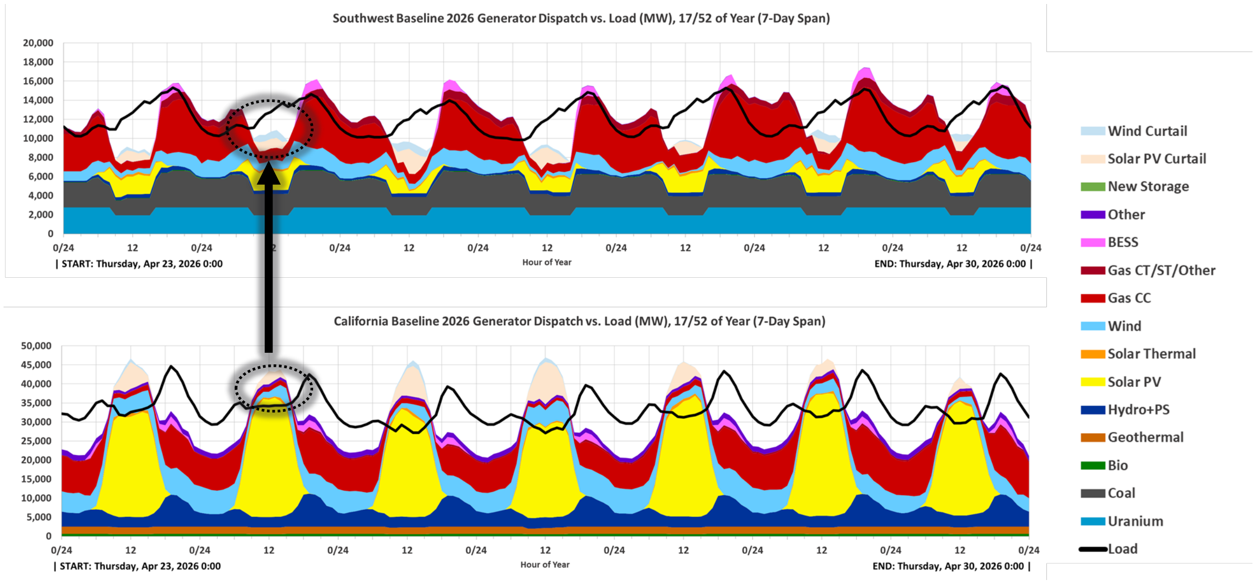
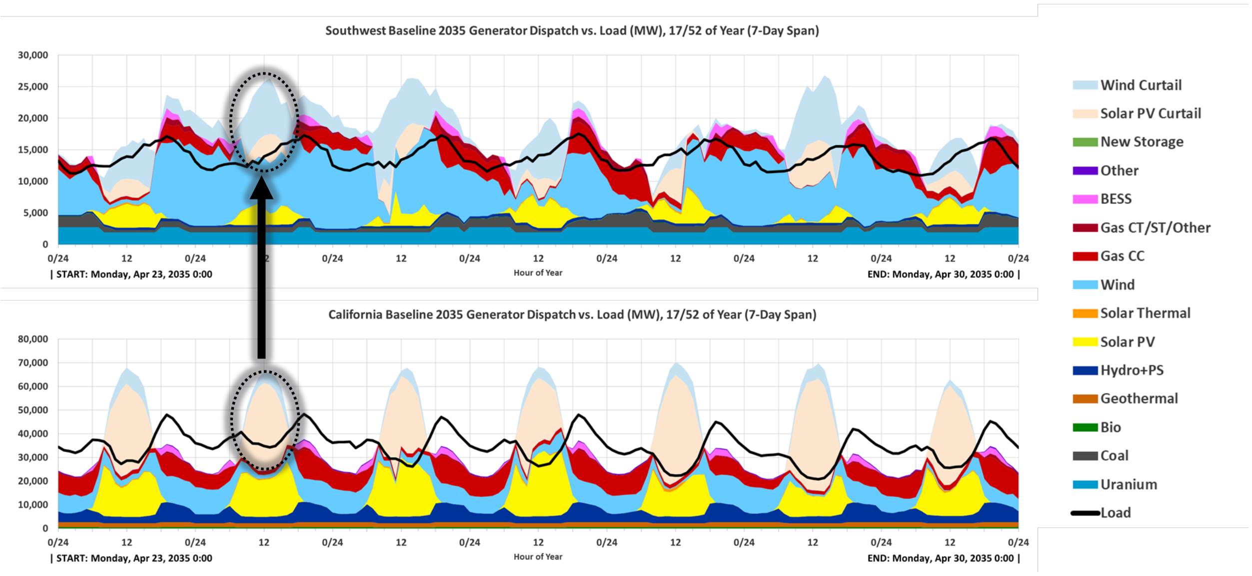


Figure 29: 2035 Operations in Southwest and California - Late April



Compare the 2026 spring-week operation diagrams, above, with those for the same week and the same two regions, but now in 2035, in **Figure 29** (also above). By 2035, the Southwest develops local renewable resources to meet its own policy goals.[29] With its higher penetration of renewables, by 2035, the Southwest experiences bouts of mid-day overgeneration and curtailment. This means California, whose renewable penetration has increased further by 2035, has lost a willing buyer for its excess power. The Southwest cannot buy California's excess power because it has too much generation of its own. In this way, the flexibility challenge for Western states with high penetrations of renewables is two-fold: renewable penetrations are increasing, which complicates operations within each region, and at the same time, there are fewer buyers available to absorb excess power. Both of these factors combine to cause extreme levels of curtailments (e.g., system inflexibility) in the 2035 timeframe.

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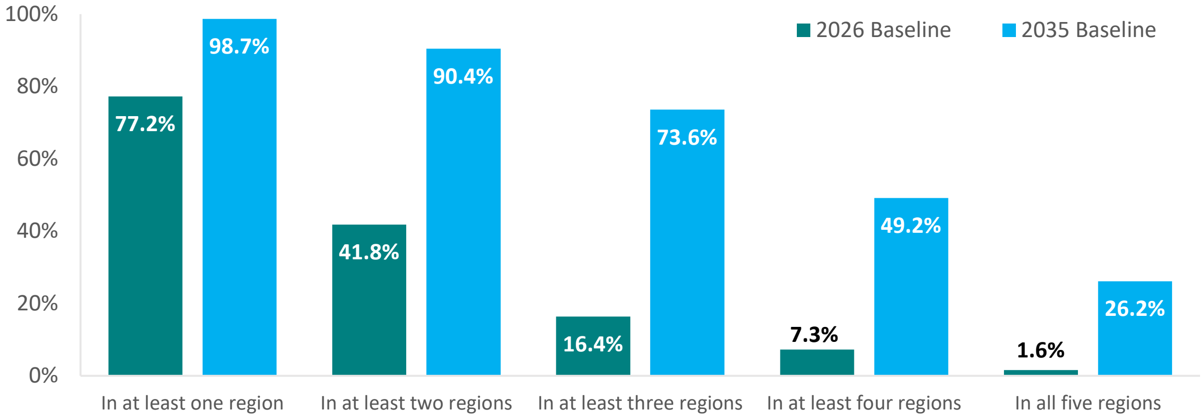
[29] The capacity expansion optimization used in this study had the Southwest build significant amounts of wind, instead of solar, because wind had higher value to Southwest loads since California's mid-day exports, at low cost, were not valuable as an avoided cost and this economic tradeoff was considered by the model in developing the portfolio.

This flexibility challenge is not unique to California and the Southwest as similar conditions occur in the Northwest, the Basin, and the Rocky Mountain regions.

Figure 30 shows that the frequency of simultaneous curtailments in the Baseline Case increases drastically from 2026 to 2035. In 2026, it is relatively rare (7% of hours) for at least four regions to have simultaneous curtailment hours. However, by 2035, at least four regions are simultaneously experiencing curtailment issues in nearly 50% of all hours.

Figure 30: Percentage of Hours in which Simultaneous Curtailment Occur



Indeed, by 2035, region's frequently have excess generation that that would, ideally, be exported and not curtailed. However, in many conditions, the realities of the system's mix mean that there are few buyers for this excess power and, thus, curtailment occurs.

On systems with high renewable penetrations, flexibility challenges are not limited to certain seasons or hours of the day

Seasonal curtailment results are presented in **Figure 31** and **Figure 32**, below. In 2026, curtailments occur in California during all seasons (with spring being the highest), while the Basin experiences its highest curtailment level (12%) in the winter, and the Southwest has curtailments totaling 12% of renewable production in the spring. Relative to 2026, these seasonal spikes in curtailment are less apparent in 2035. By this time, penetrations are sufficiently high that "normal" conditions can have curtailments, and they can occur in any season. A number of these curtailments are due to transmission constraints, which will not vary by season. Regardless, as regions push toward higher penetrations, expect inflexibility to occur, in some regions, for much of the year.

Figure 31: 2026 Baseline Case Seasonal Curtailment Summary[30]

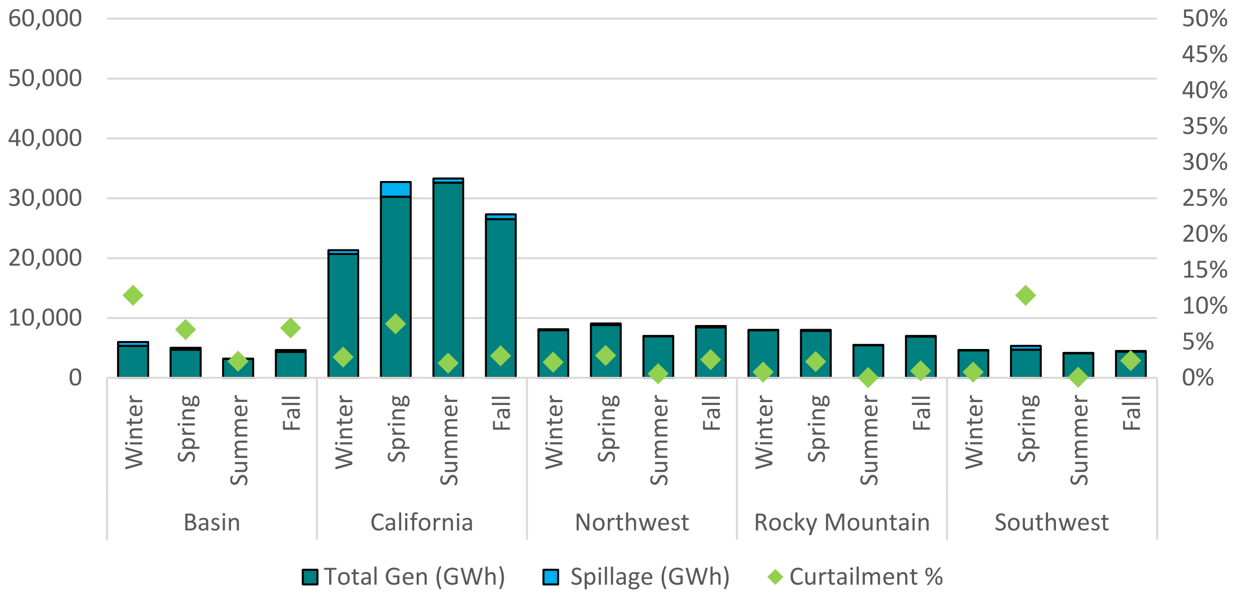
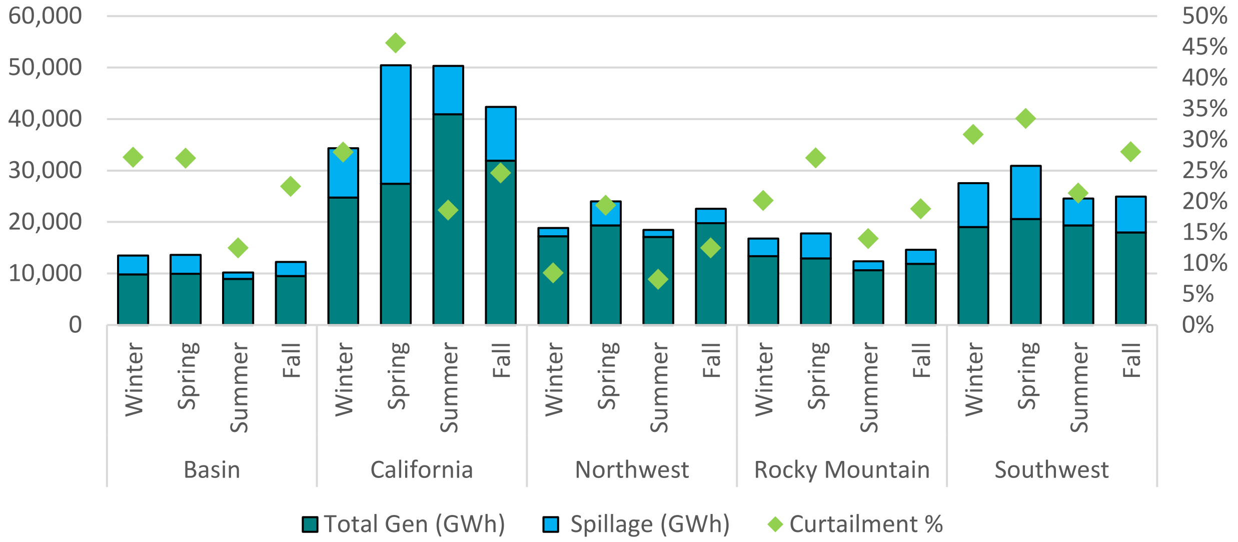


Figure 32: 2035 Baseline Case Seasonal Curtailment Summary



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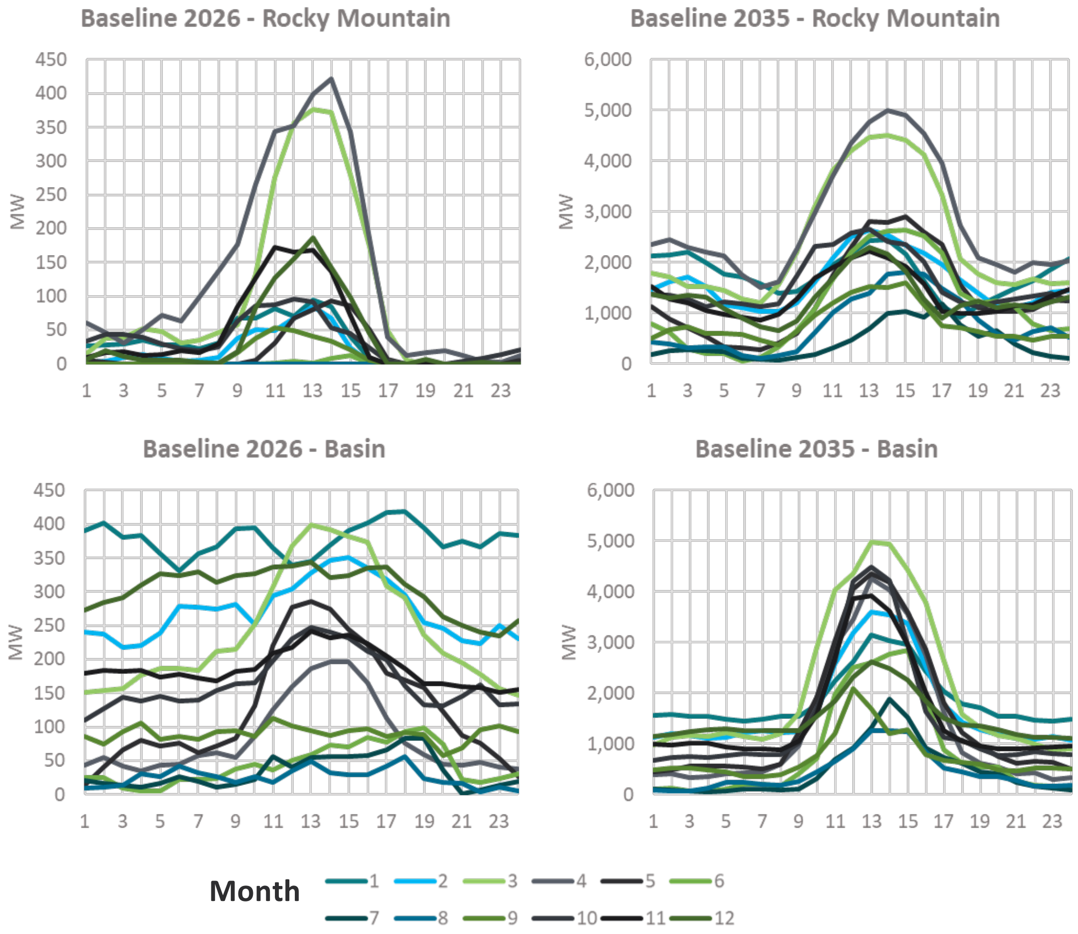
[30] Total Gen represents total renewable generation. "Spillage" refers to curtailed output not delivered, and "curtailment %" references to curtailments, or spillage, as a percentage of total generation.

Curtailments can also occur during all hours of the year. This is demonstrated below in **Figure 33**, which displays hourly average curtailments, by month, for the Rocky Mountain and Basin regions in the 2026 and 2035 Baseline Cases.

Figure 33: Hourly Curtailments in Baseline Cases for Rocky Mountain and Basin



This average hourly curtailment data shows that, in 2026, the Rocky Mountain region experienced almost all of its curtailment during day-time hours. By 2035, the region had night-time curtailments due to low-load and high-wind conditions. The opposite occurs in the Basin. In 2026, excess wind production (at relatively low levels) was curtailed during extended portions of the day. However, by 2035, the Basin added significant solar resources and most of its' curtailment occurred during the daytime hours.

Net load ramps increase as regions add renewable resources

In additional to curtailments, flexibility challenges in a given system can be measured by net load ramping. In **Table 21** maximum 3-hour gross and net load ramps are presented by region for the Baseline Case 2026 and 2035 studies. The gross load ramps are provided as context for the net load ramps.

Table 21: Maximum 3-Hour Gross and Net Load Ramp[31]

Region	Max Ramp in 2026			Max Ramp in 2035		
	Gross Load (MW)	Net Load (MW)	Net/Gross (%)	Gross Load (MW)	Net Load (MW)	Net/Gross (%)
Basin	1,601	2,833	**177%**	1,987	4,323	**218%**
California	13,682	40,120	**293%**	20,142	54,532	**271%**
Northwest	7,525	7,847	**104%**	8,099	11,139	**138%**
Rocky Mountain	2,195	3,772	**172%**	2,228	6,030	**271%**
Southwest	5,686	6,705	**118%**	7,174	13,488	**188%**

Ramping needs grow significantly during the study period. By 2035, California will need to dispatch more than 18,000 MW *per-hour* to meet its maximum 3-hours net load ramp. The Northwest and Southwest regions have the second-highest ramping requirements. However, the Northwest's net load ramp was 38% higher than its gross-load ramp – this was the smallest increase from gross to net load ramping and is likely due to the fact that the Northwest has a relatively low penetration of solar, which has a steep fall-off in afternoon production that can lead to extreme net load ramping.

Figure 34 demonstrates ramping conditions for 2035. The first figure is for California in July 31, 2035 and there is a 47 GW 3-hour net load ramp in the afternoon as solar production falls off. In the second figure, the Northwest region experiences its maximum ramp (11 GW) during an evening load spike on December 17, 2035. Incremental combined-cycle units are dispatched to

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[31] Gross load accounts for distributed generation.

cover the spike. California meets its ramp partially with its combined cycle fleet (some of which is operating at minimum generation levels during the day to ensure sufficient capacity is online for the evening ramp), as well as with imports, battery storage discharge, combustion turbine dispatch, and pumped storage hydro.

Figure 34: Sample Days in 2035 with Extreme 3-Hour Ramps

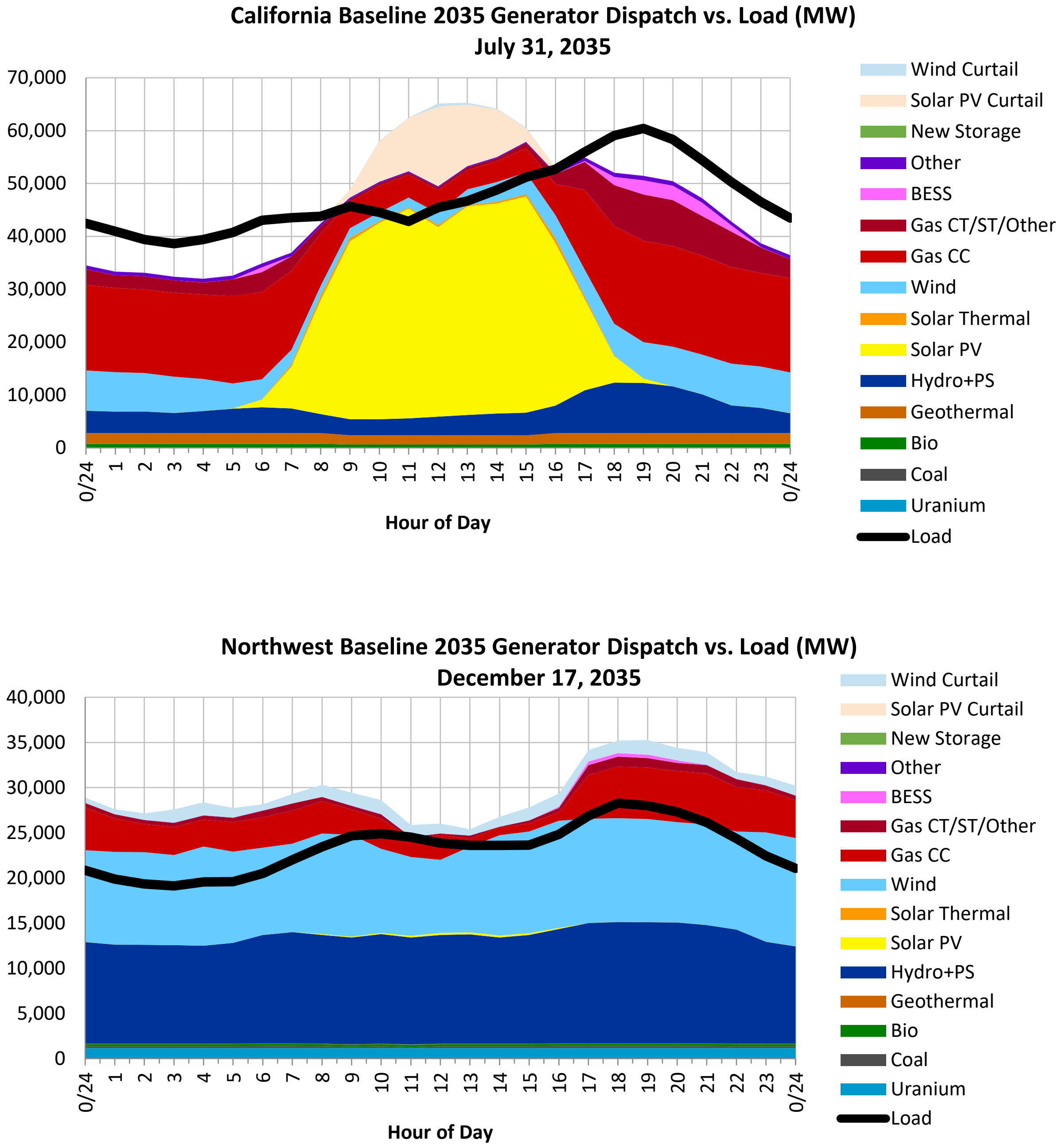
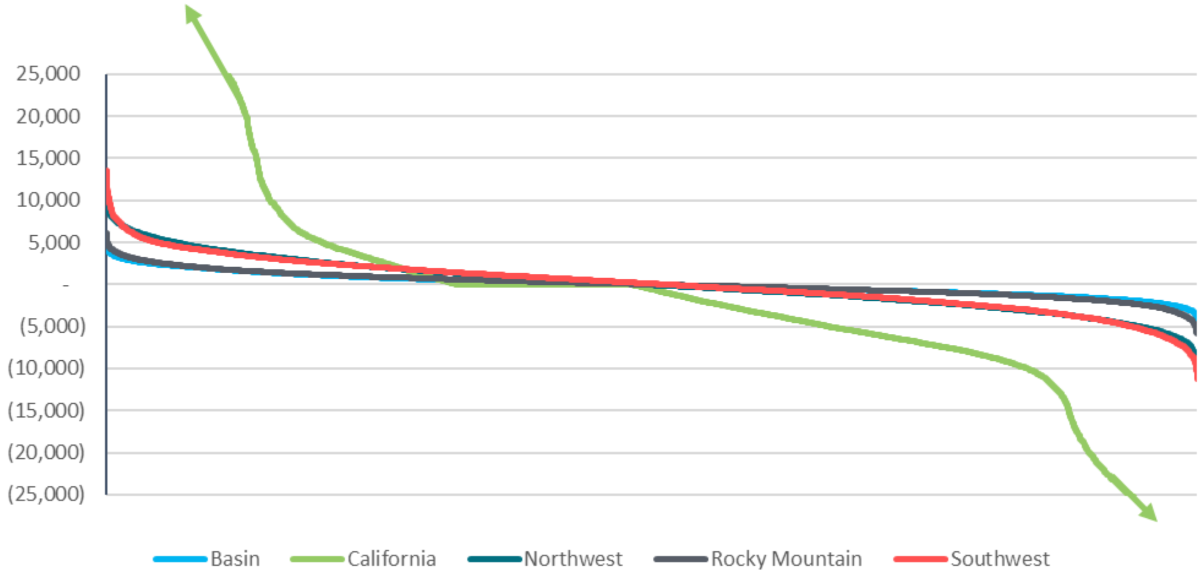


Figure 35 rank orders, by size, each region's 3-hour net load ramps for the 2035 Baseline Case. There are three tiers: California has the most extreme 3-hour net load ramp requirements, followed by the Southwest and Rocky Mountain (in the second tier), and then the Basin and the Northwest. The tails at the end of each curve indicate that all regions experience extreme ramping events that require multiples of ramping capability than what is typically used for most hours of the year.

Figure 35: One Year of 3-hour Net Load Ramps in 2035 Baseline Case

(Sorted largest to smallest for all five regions)



5.4 Transmission Sufficiency and Power flows

One of the unique elements of this study was its granular representation and analysis of the Western transmission system. Many studies that contemplate high penetrations of renewables represent only major interregional transmission constraints or may not even consider transmission limitations at all. Indeed, transmission is an important element of system flexibility because existing and new transmission assets can be repurposed throughout their life to serve different purposes (e.g., reliability can cause a transmission project to be built, but over time its primary value could change). Transmission capability is important for transferring renewable power from its interconnection point to loads, while also providing opportunities for interregional power exchange. For reasons like these, this study includes detailed analysis of the Western transmission system to investigate, at a high level, impacts to power flows and the ability of the bulk transmission system to handle the magnitude of renewable energy contemplated in this study. The goal of the study was to evaluate the extent that the transmission system might act as a flexibility barrier under high penetrations of renewables.

Results indicate that interregional power transfers may change significantly from historical levels

In both the 2026 and 2035 Baseline Cases, regions in the West rely heavily on interregional power transfers to serve their loads. **Figure 36**, below, demonstrates that WECC transfer path flows are dramatically different in 2026 and 2035 compared with their historical levels. A good example is California, which by 2026 is regularly exporting power (e.g., negative flows on Path 65 and Path 66, positive flows on Path 49) whereas that rarely happened historically (although this trend toward exporting has begun to show in recent years). The duration curves in **Figure 37**, which rank hourly flows from largest to smallest, further demonstrate how the characteristic of the WECC transfer path flows differ between history and the 2026 and 2035 Baseline Cases.

Figure 36. Average Hourly WECC Transfer Path Power Flows (average day) for Baseline 2026 and 2035 Cases versus Historical Flows (aMW)

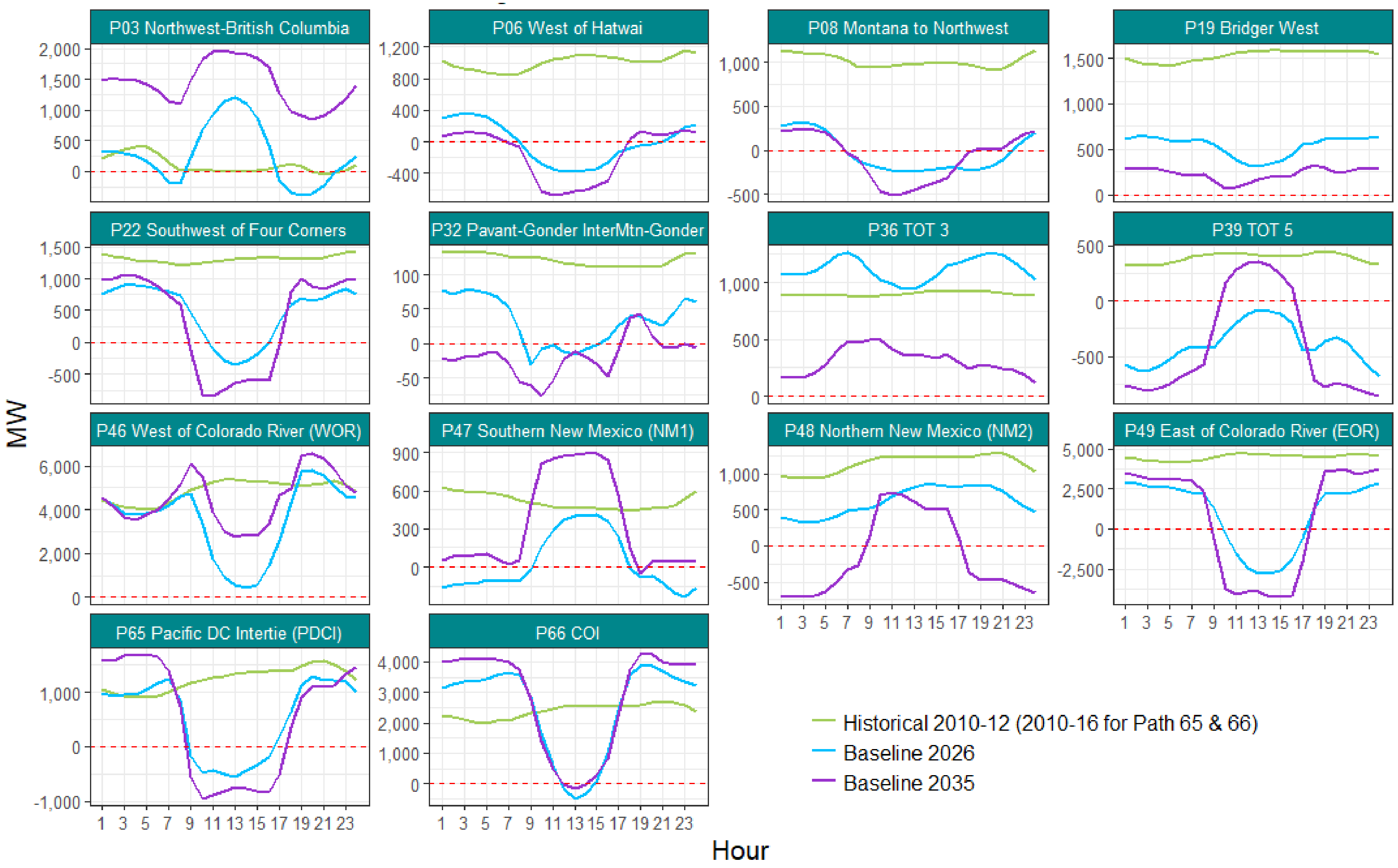
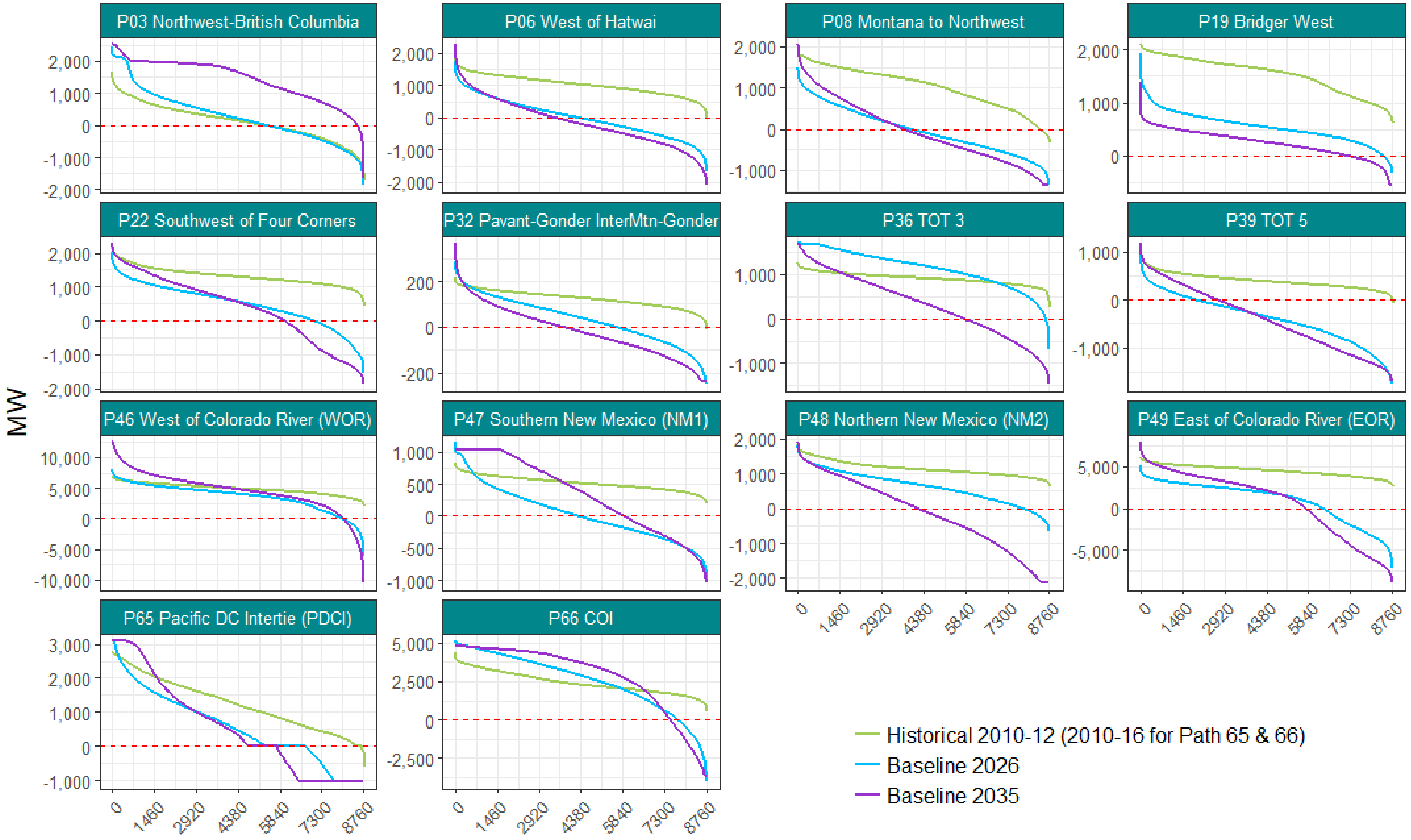


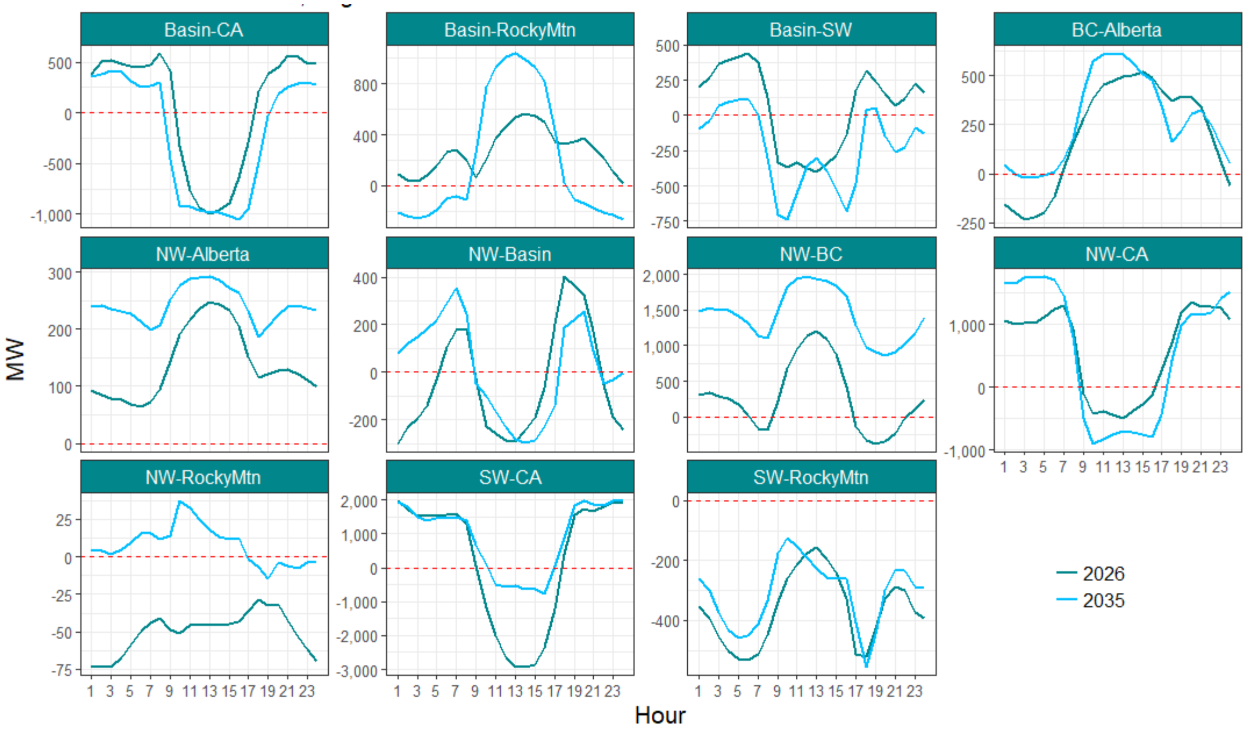
Figure 37. Duration Curves Providing the "Profile" of Hourly WECC Transfer Path Power Flows for Baseline 2026 and 2035 Cases versus Historical Flows (MW)



Diurnal changes in flow patterns become the new norm

Historically, bulk power in the West generally flows from east-to-west and north-to-south. With few exceptions (Denver Metro, Salt Lake City, Phoenix Metro), major loads are along the coastal states, so it follows that power flows in that direction. In the 2026 Baseline Case results, this coastal flow occurs in many conditions. However, study results indicate flow directions can change on an hour-to-hour basis. Below, in **Figure 38**, we see average hourly flows between regions in the Baseline 2026 and 2035 cases. These results show that, in a given hour or for a series of hours, flows can be from the Southwest to California, for instance, and then hours later flows can be in the complete opposite direction – from California to the Southwest. This diurnal flow pattern exists for several region-to-region ties: Basin-California, Basin-Southwest, Northwest-Basin, and Northwest-California.

Figure 38: Average Hourly Interregional Power Flows (average day) for Baseline 2026 and 2035 Cases (aMW)[32]



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[32] Positive values indicate flow direction from the first region to the second region (example: Basin-California – positive is from Basin to California).

This hour-to-hour flow volatility trend continues into 2035. Flows between Basin-Rocky Mountain also begin to adopt diurnal flow patterns, while flows from the Northwest to Rocky Mountains largely flip directions – in 2026 flows are generally toward the Northwest region and by 2035 flows are toward the Rocky Mountain region.

In certain instances, interregional power flows can decrease under high penetrations of renewables

When regions have more power than they can use, it is economical to export the excess. However, when multiple neighboring regions are long on power in a given condition, exports are no longer economic since the potential buyer already has all the power they need. Therefore, when two neighboring regions simultaneously experience overgeneration conditions, interregional power flows can *decrease* under high penetrations of renewables. This dynamic is discussed in Section 5.3 and shows up again here in the context of power flows. The best and most prominent example of this behavior in this study is with California and the Southwest. The average daily flow data for the 2026 Baseline Case, above, shows California's average export to the southwest during mid-day solar production hours peaking at 3 GW. However, by 2035, this mid-day export falls to less than 1 GW (on average). This *reduction* in export flows in 2035 (as compared to 2026) occurs with deeper renewable penetrations because as simultaneous multi-region overgeneration conditions occur more regularly, there are reduced opportunities to export overgeneration between regions.

The near-term transmission system, as represented this study, proved to be robust from a reliability standpoint

Energy Strategies performed a transmission "sufficiency analysis" using snapshot power flow cases created from the Baseline 2026 and 2035 Baseline Case economic dispatch studies. The hourly results from the Baseline Case studies were screened to identify two stressed conditions for each study year: one peak demand condition and one peak renewable condition.[33] Both scenarios retained the Baseline Case transmission topology. The dispatch conditions were:

- **2026 Peak Demand** – System demand of 156 GW with 7% renewable penetration.
    - **Hour:** 7/23/2026, HE 19

- **2026 Peak Renewables –** System demand of 83 GW with 50% renewable penetration.
    - **Hour:** 3/29/2026, HE 10

- **2035 Peak Demand** – System demand of 167 GW with 15% renewable penetration
    - **Hour:** 8/01/2035, HE 20

- **2035 Peak Renewables –** System demand of 97 GW with 66% renewable penetration
    - **Hour:** 9/29/2035, HE 9

For these conditions, we analyzed N-0 (P0) and N-1 (P1) contingency conditions for the high-voltage transmission system (>200 kV). Transmission monitoring and violations included everything with voltages at or above 200kV, including transformers with a high-side winding voltage at or above 200kV. The goal of the study was to identify the number and magnitude of thermal overloads, for a given sub-regional area, to help determine if the system has sufficient transmission to deliver power to loads (for the given condition) in a reliable fashion. Notably, since we connected new generators assumed in this study to high-voltage substations, we anticipated many transformer overloads and this was confirmed in the results. Additionally, we focused the review of study results on comparing case results as the study cases did not include transmission upgrades that might be required to ensure system performance under normal load growth and operating conditions. Results from the power flow analysis are summarized below:

- **In 2026, peak demand issues were more severe than peak renewable issues in California and Arizona. Peak renewable issues were more severe than peak demand issues in the Northwest, Wyoming, and Colorado. New Mexico, Utah, Nevada, Idaho, and Montana had relatively few system issues in both conditions.**

- **In 2035, peak demand issues were more severe than peak renewable issues for almost all areas of the system. The exceptions were the Eldorado Valley (Las Vegas) and Wyoming. All other areas of the system had more issues in the peak demand case than the peak renewable case.**

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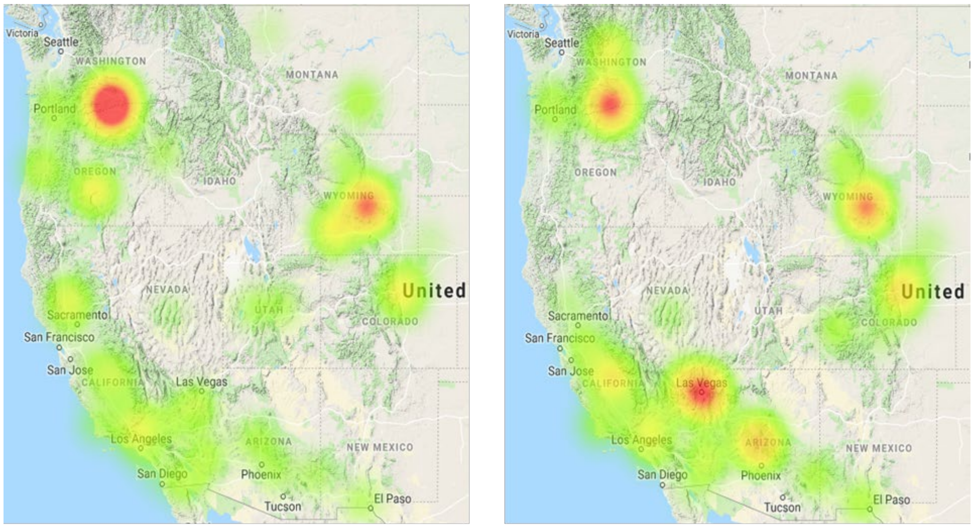
[33] These conditions were calculated for the Western Interconnection, not just Western States.

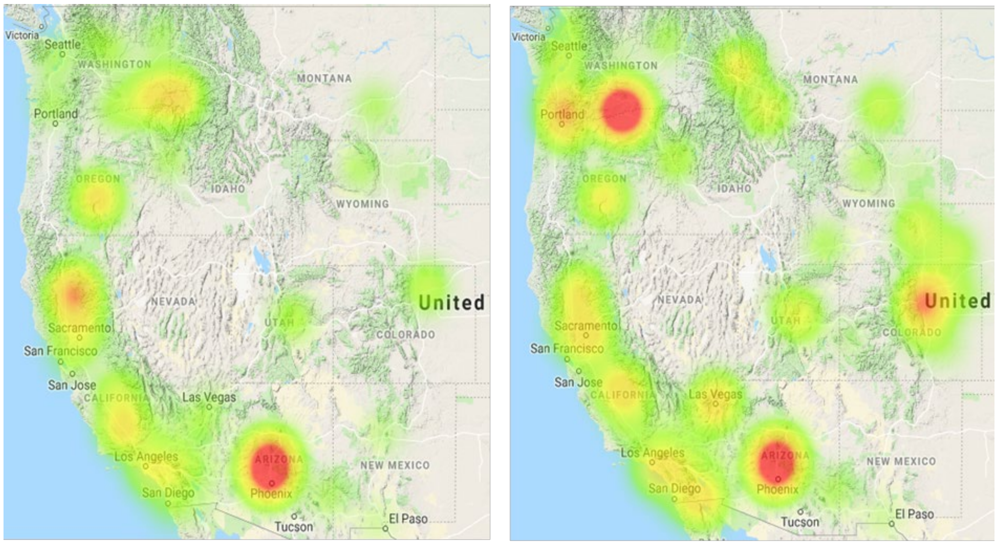
New Mexico, Utah, Nevada, Montana, and Idaho continued to have relatively few issues in both study conditions.

System violations are shown below in heat-map format. Red areas indicate more numerous and severe loading issues. Light green indicates areas with minimal violations.

Figure 39: Heat Map Summarizing Reliability Study Results



2026 Peak Renewables 2035 Peak Renewables



2026 Peak Demand 2035 Peak Demand

This analysis does not purport to make any findings with regards to the need for specific transmission projects, nor does it imply that the system definitively will or will not be reliable in the years studied. Such a determination was not the goal of the study. The goal was to "stress-check" the assumed transmission system to determine if its capabilities were reasonably aligned with the modeled renewable penetration. Indeed, connecting new resources to the system may drive the need for certain transmission additions. However, review of the study results does suggest that the issue on the system caused by high renewable production are generally consistent with high load-driven issues, which means there is the potential that system upgrades required to address normal peak demand growth may also resolve some issues identified in the peak renewables scenario. It also suggests that constraints on the transmission system, which could complicate delivery of the simulated amount of renewable power, are generally isolated to certain pockets on the system.

With few exceptions, there is very little system congestion in 2026, but certain transmission constraints represent a material barrier to achieving the assumed policy targets in 2035

We report transmission congestion on major WECC Paths in **Table 22** using the U75 and U99 metrics discussed in Section 3.3. With few exceptions, there is very little transmission congestion on these paths in 2026 (based on the % of hours in which flows are above 99% of the path rating). Some of the paths are well utilized, as indicated by the U75 metric, but this does not mean there is an economic incentive to upgrade their capacity. Congestion is significantly higher by 2035. The increase is especially true on the interfaces connecting California to the Northwest (P66 and P65), paths connecting New Mexico to the rest of the system (P47 and P48), transmission out of Montana (P08), and along the Wyoming-Colorado interface (P36).

Table 22: Baseline Case Transmission Use and Congestion on WECC Paths

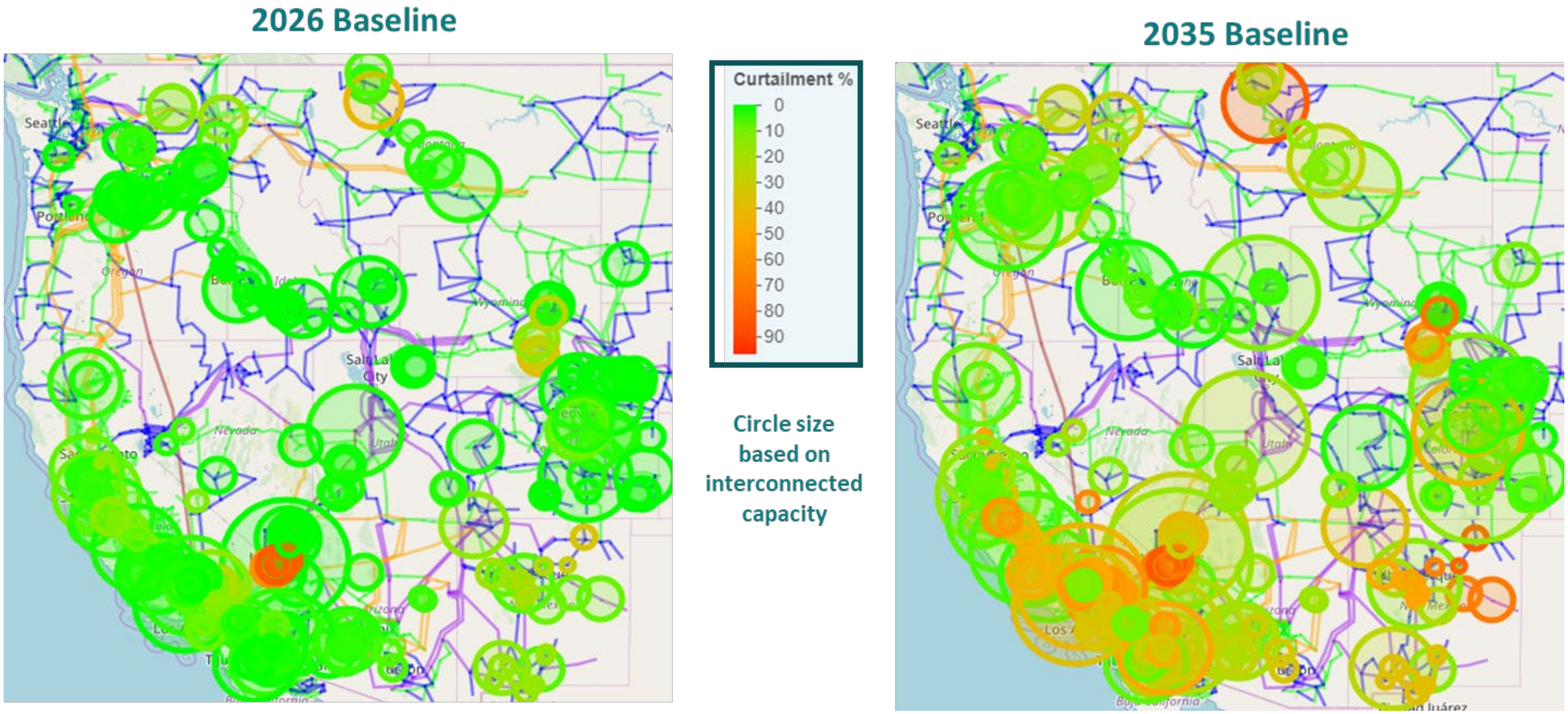
			Baseline 2026		Baseline 2035	
Path	Path Name	Direction	U75	U99	U75	U99
P03	P03 Northwest-British Columbia	S->N	0.0%	0.0%	5.6%	0.0%
P06	P06 West of Hatwai	E->W	0.0%	0.0%	0.0%	0.0%
P08	P08 Montana to Northwest	E->W	3.4%	0.1%	19.3%	5.2%
P19	P19 Bridger West	E->W	0.1%	0.0%	0.0%	0.0%
P22	P22 Southwest of Four Corners	E->W	0.1%	0.0%	2.8%	0.1%
P32	P32 Pavant-Gonder InterMtn-Gonder 230 kV	E->W	6.7%	1.7%	11.4%	3.7%
P36	P36 TOT 3	N->S	61.7%	23.2%	21.3%	4.9%
P39	P39 TOT 5	W->E	0.4%	0.0%	1.4%	0.0%
P46	P46 West of Colorado River (WOR)	E->W	0.0%	0.0%	0.4%	0.0%
P47	P47 Southern New Mexico (NM1)	N->S	2.1%	0.1%	24.2%	6.2%
P48	P48 Northern New Mexico (NM2)	NW->SE	0.2%	0.0%	1.7%	0.2%
P49	P49 East of Colorado River (EOR)	E->W	0.0%	0.0%	1.6%	0.0%
P65	P65 Pacific DC Intertie (PDCI)	N->S	13.9%	1.9%	28.0%	9.2%
P66	P66 COI	N->S	20.7%	1.1%	47.3%	5.9%

There is a potential need for significant transmission expansion to meet long-run policy goals, depending on where resources are sited

Figure 40 shows a geographical view of curtailment in the Baseline Case 2026 and 2035 production cost model simulations. The 2026 Baseline Case has isolated incidents of severe curtailments (>20%). These outliers can sometimes be addressed by relocating the resource, changing the resource type, or adding storage to the system. In some instances, the only option to mitigate highly specific “hot spots” of curtailments (or system inflexibility) is with transmission expansion.

The curtailments in the 2035 Baseline Case are more widespread, geographically, and are more severe. The 2035 study likely requires transmission upgrades to reduce congestion that is leading to renewable curtailment

Figure 40: Renewable Curtailment in the Baseline Case



2026 Baseline

2035 Baseline

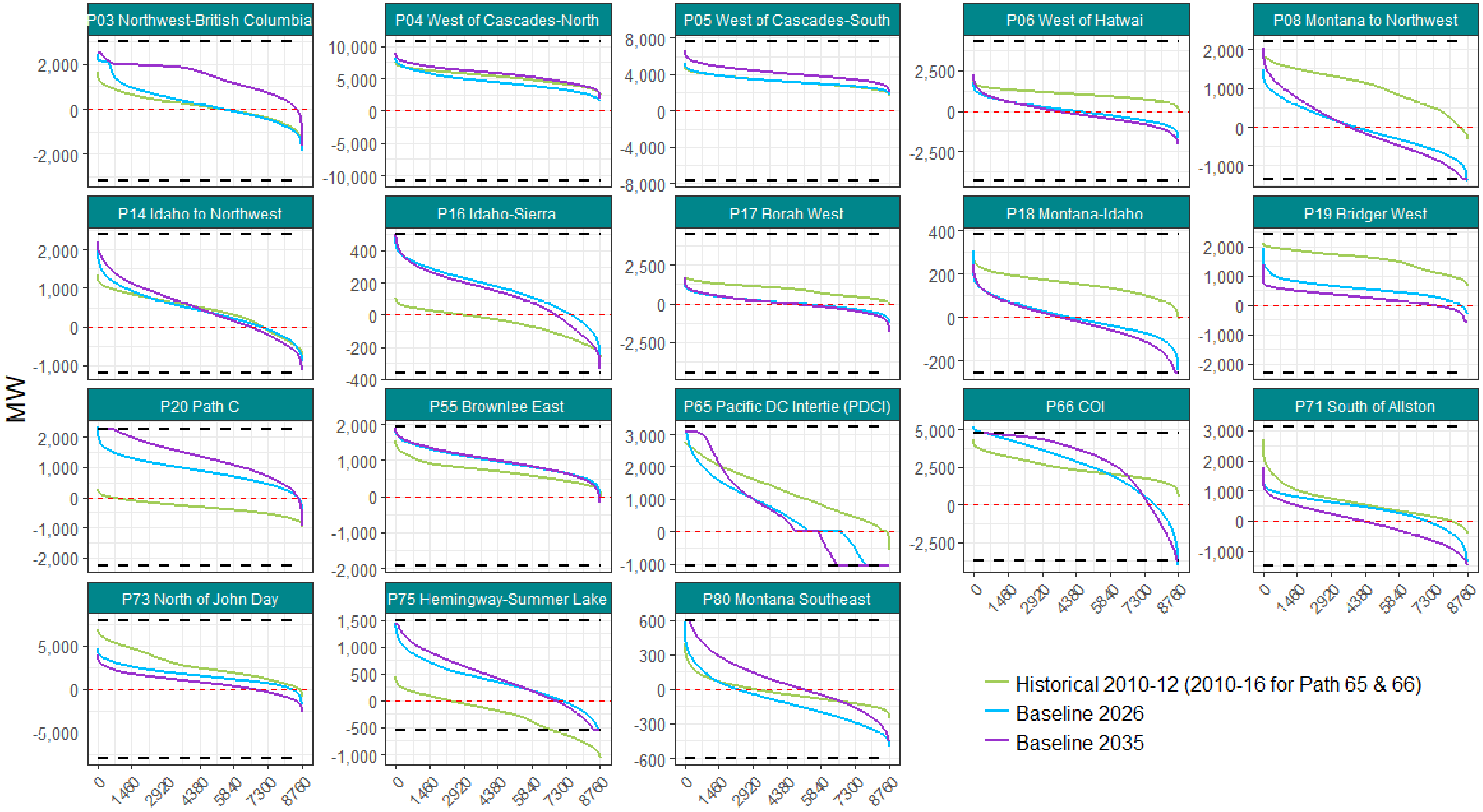
Circle size based on interconnected capacity

While the Baseline Case transmission system was held static, we did study alternative transmission configurations to attempt to reduce curtailments and increase system flexibility in the Integration Strategies scenario, which is addressed in Section 6.0.

Congestion in the Northwest grid is minimal throughout the study period

In this study, Path 65 (Pacific DC Intertie a.k.a. PDCI) was the only Northwest-related WECC transfer paths with a noticeable amount of congestion in 2026 and 2035 (1,020 and 2,258 hours out of the year, respectively). **Figure 41** provides duration curves for the flow on WECC transfer paths in and bordering the Northwest region for 2026 and 2035 compared with their average historical flow, in which congestion (if any) shows up as a flat line along at the highest and/or lowest levels of flow. This study result indicates that if the system is used up to its reliability limits and a flow- or market-based congestion management system is used to manage flows (such as what is assumed in our simulations), the bulk transmission interfaces in the Northwest can handle significant renewable penetrations without facing severe congestion.

Figure 41: Duration Curves Providing the "Profile" of Hourly WECC Transfer Path Power Flows in and bordering the Northwest region for Baseline 2026 and 2035 Cases versus Historical Flows (MW)[34]



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[34] Hourly flows for the entire year sorted largest to smallest to show how often the flow is at certain levels.

6.0 SCENARIO CASES

Two scenario studies were created to complement the Baseline Case. The scenarios test the impact of assumptions that increase and decrease system flexibility. Study results and assumptions for the two scenarios, which are introduced in Section 1.3, are summarized below.

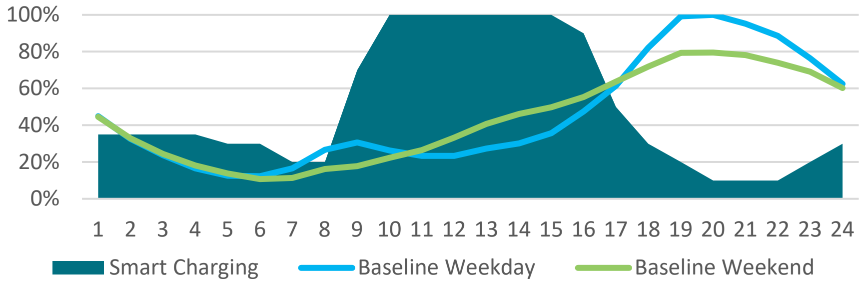
6.1 Integration Strategies Scenario Assumptions

This scenario is referred to "Integration Strategies" because it tests several strategies intended to increase grid flexibility. This scenario was built from the Baseline Case and was studied in the security-constrained economic dispatch model. The scenario assumes:

- **A more diverse resource –** The Baseline Case expansion in the Northwest included mostly new wind and very little solar. This scenario assumes that more balanced portfolio is built, exchanging 2,400 MW of the new wind for the same capacity of new solar located in southern Oregon and western Idaho.

- **Managed and "smart" charging of EVs –** The Baseline Case assumed an EV charging pattern developed by the CEC and NREL using the Electric Vehicle Infrastructure Projection Tool (EVI-Pro). This scenario assumes as "smart" charging shape in which EV charging is timed and managed to help absorb mid-day solar production.

Figure 42: Per-unit EV Charging Shape for 1-Day



- **New sub-regional and regional transmission upgrades help deliver renewable power to loads –** In certain areas, renewables added to the Baseline Case were not delivered to loads because of transmission constraints. This scenario expands the transmission system with a series of targeted upgrades designed to mitigate transmission congestion. In the case of California, since the intra-region congestion was so severe, we assumed that California would build upgrades necessary to deliver resources to in-state loads. This assumption was approximated in the modeling by removing most in-state transmission constraints in California. A summary of the assumed upgrades is provided below.

Figure 43: Assumed Transmission Additions in Integration Strategies Scenario

State	Transmission Additions
WY	500-kV connection from Wyoming to Eldorado Valley (Nevada)
CO	Denver-area upgrades to 230-kV system to increase transfer capability into Denver Metro
NM	• Albuquerque area reinforcements (removed certain constraints) • 345-kV upgrade to deliver wind from Eastern New Mexico • Ojo – Norton upgrade and increased capacity to Four Corners
CA	Unmonitored all individual in-state transmission lines, retained path monitoring to enforce sub-regional constraints
NW	• Path 8 upgrade adds 600 MW • Minor upgrade: Addressed interconnection issues in Northern Oregon and Coulee area (2035 study only) • Minor upgrade: new 230-kV Idaho-Washington upgrade (2035 study only)

- **Relocation of generation exacerbating certain transmission constraints –** Resource siting in the Baseline Case was adjusted and optimized based on our review of Baseline Case study results and transmission congestion.

- **Long- and medium-duration storage is deployed in significant capacities –** The capacity expansion modeling did not add a reasonable amount of storage to the Baseline Case, so for this scenario we reviewed the magnitude of renewable curtailments and sized additional long- and medium-duration storage commensurate with the amount of curtailments. We used proposed projects, by state, to cap the available long-duration storage resources to reasonable levels. Regional-level assumptions for incremental storage in the scenario are provided in **Table 23**.

Table 23: New Storage Assumed in Integration Strategies Scenario (GW)

Region	2026		2035	
	Medium-duration Storage (4-hour)	Long-duration Storage (12-hour)	Medium-duration Storage (4-hour)	Long-duration Storage (12-hour)
Basin	0.96	0.21	4.92	1.09
California	0.80	0.27	14.81	4.94
Northwest	0.17	0.08	1.94	0.97
Rocky Mountain	0.03	0.01	3.84	0.85
Southwest	0.13	0.04	6.98	2.33
TOTAL	**2.09**	**0.61**	**32.49**	**10.18**

In sum, the Baseline Case resource mix was adjusted (primarily by adding storage), transmission was added and certain customer loads were shifted. **Figure 44** compares the resource mix and storage deployment assumption for the Integration Strategies with the Baseline Case portfolios, by region. The Integration Strategies scenario was designed to investigate what changes to the Baseline Case future might be necessary in order to increase system flexibility and achieve renewable penetration consistent with state policy targets assumed in this study.

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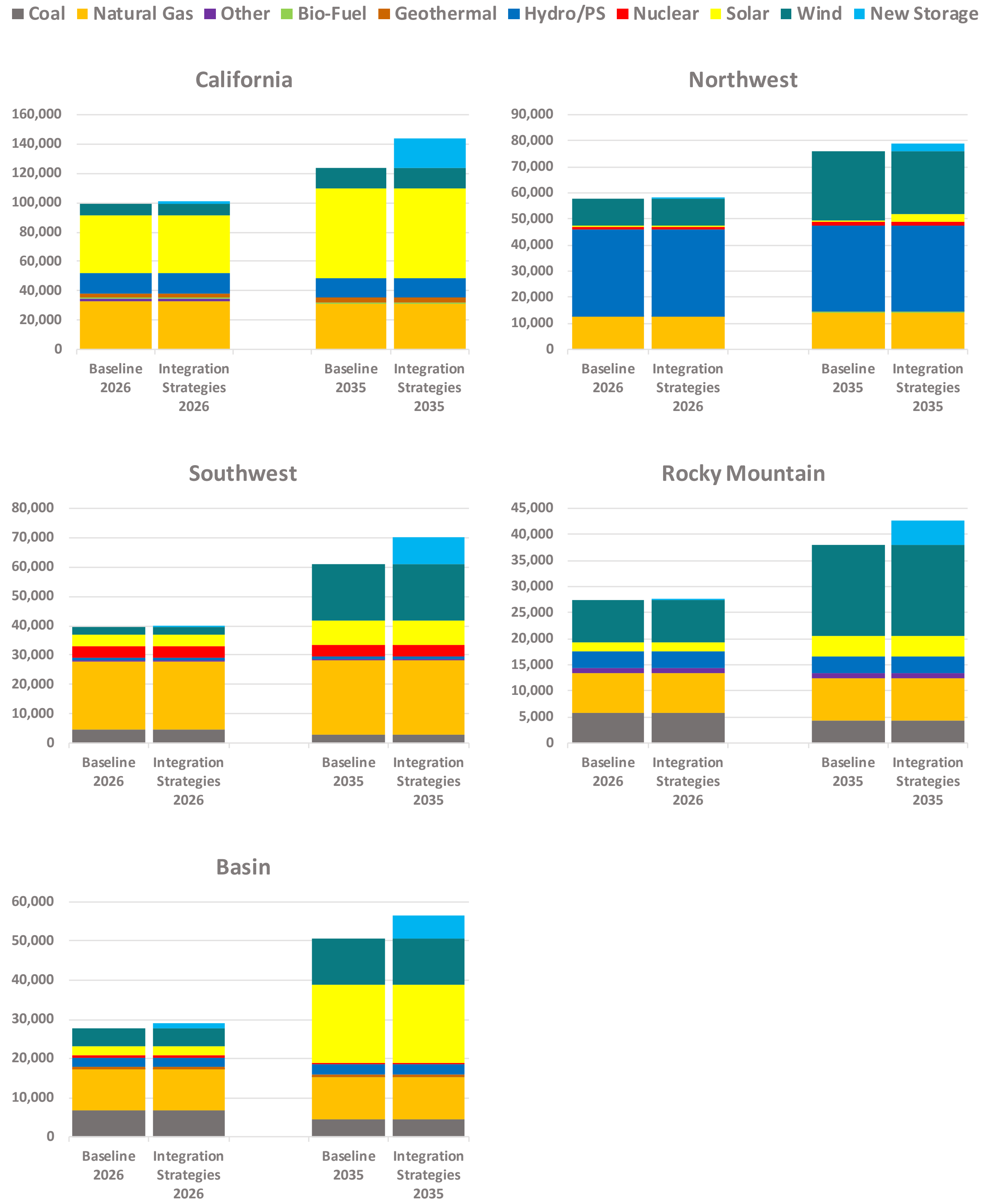
Figure 44: Summary of Cumulative Generation (MW) in Baseline and Integration Strategies Cases



6.2 Limited Regional Coordination Scenario Assumptions

The Baseline Case assumes a highly coordinated future system where today's bilateral trading construct no longer exists and power trade is optimized, free of transmission hurdles, in real-time and day-ahead timeframe. Indeed, this future may not come to pass, so this scenario was designed to investigate a future with a less coordinated system and transmission operations more in line with today's system. To attempt to reflect less optimal operations and transmission use, thereby reducing system flexibility, this scenario assumes the following changes to the Baseline Case:

- **Transmission service wheeling charges are added –** Hurdle rates are applied to all day-ahead transactions and no-cost wheeling between areas is only available to those entities currently or planning on participating in the Western EIM (at the historical usage level). This no-cost wheeling between areas only applies to the real-time dispatch step. All day-ahead exchanges face the full cost of transmission wheeling (the non-firm rate).

- **Path limits are limited to historical maximum flows or Western EIM transfer amounts –** Historical WECC path data from 2010-2012 was used to identify historical maximum flows. In some instances, transmission capacity dedicated to Western EIM usage, today, exceeded these flows so we adopted the higher of the two values to represent less optimized usage of the transmission system.[35]

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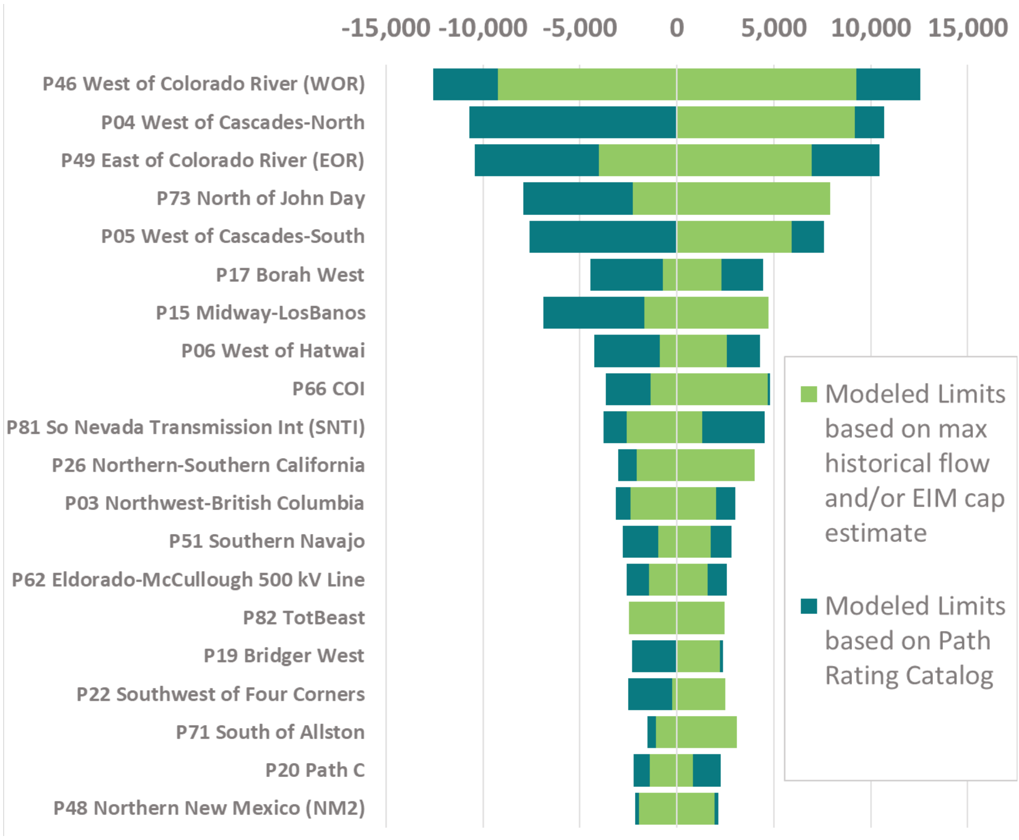
[35] For Path 65 and 66 we used BPA data, which increased data availability to 2013-2016.

Figure 45: WECC Path Limits Compared with Transfer Limit Assumed in Scenario



- **Ramping of flows on WECC paths limited to historical 1-hour maximum** – As a means to constrain system usage to sub-optimal maximums, the scenario limits 1-hour changes in path flows to historical maximum 1-hour flow changes.

This counter-factual scenario was intentionally designed to reduce system flexibility, as compared to the Baseline Case. By reflecting a less integrated and optimized system, we sought to learn about the implications of status-quo operational methods, in which most of the power in the West is traded bilaterally and there is inefficient "pancaking" of transmission rates.

6.3 Scenario Study Results

The scenario case changes above were made to the production cost modeling datasets used to study the Baseline Case in 2026 and 2035. What follows is a summary of the key results and findings from these studies.

The flexibility solutions assumed in the Integration Strategies increased system flexibility and decreased generator curtailments

Table 24 summarizes the curtailments and renewable penetrations for the Integration Strategies studies. As compared to the Baseline Case, the Integration Strategies case had deeper renewable penetrations and fewer curtailments. In 2026, the Baseline Case had 3% curtailments and achieved a 36% clean energy penetration, while the Integration Strategies case had nearly 0% curtailment and achieved a 37% clean energy penetration. In 2035, the differences between the two cases become more pronounced. In 2035, the Integration Strategies scenario had only 9% curtailments compared to 20% curtailments in the Baseline Case. The Integration Strategies scenario achieved a 2035 clean energy penetration of nearly 70%, which was much higher than the Baseline Case (52%) and sufficient to meet, and exceed, state policy requirements.

Table 24: Integration Strategies Curtailment and Clean Energy Penetration

Regional load served by clean energy[36]	2026		2035	
	Curtailment (%)	Penetration (%)	Curtailment (%)	Penetration (%)
Basin	1%	13%	12%	34%
California	0%	51%	8%	81%
Northwest	1%	26%	7%	68%
Rocky Mountain	0%	37%	11%	76%
Southwest	0%	35%	8%	55%
Western U.S.	**0%**	**37%**	**9%**	**69%**
	Clean energy target: 33%		**Clean energy target: 64%**	

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[36] Renewable energy in the model served both local and remote load and this table reports the renewable energy based on the location of the load its serving. For example, Southwest solar remotely serving California load is reported as California renewable energy in this table.

The Limited Regional Coordination scenario decreased system flexibility and increased generator curtailments

Table 25 summarizes curtailments and renewable penetrations for the Limited Regional Coordination scenarios.

Table 25: Limited Regional Coordination Curtailment and Clean Energy Penetration

Regional load served by clean energy[37]	2026		2035	
	Curtailment (%)	Penetration (%)	Curtailment (%)	Penetration (%)
Basin	23%	13%	51%	30%
California	12%	46%	33%	53%
Northwest	2%	26%	15%	56%
Rocky Mountain	3%	32%	26%	54%
Southwest	7%	34%	36%	34%
Western U.S.	**11%**	**34%**	**46%**	**49%**
	Clean energy target: 33%		**Clean energy target: 64%**	

In both study years, clean energy curtailments increased under the Limited Regional Coordination scenario as compared to the Baseline Case due to reduced system flexibility. In 2026, the Limited Coordination Scenario had 11% curtailments in the Western U.S., while the Baseline Case had 3%. Because of this, the Limited Coordination Scenario achieved a 2026 clean energy penetration lower than the Baseline Case: 34% versus 36%. These trends continue in 2035. Curtailments in the Limited Coordination scenario increase to 46% compared to 33% in the Baseline Case, and a 49% renewable penetration is achieved compared to the 53% clean energy penetration in the Baseline Case. These results illustrate the degree of system flexibility and increased ability to achieve policy requirements that is achieved through regional coordination.

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[37] Renewable energy in the model served both local and remote load and this table reports the renewable energy based on the location of the load its serving. For example, Southwest solar remotely serving California load is reported as California renewable energy in this table.

System inflexibility events are less severe in the Integration Strategies scenario and more severe in the Limited Regional Coordination scenario

In this study, renewable curtailment is used as one measure of grid inflexibility. In **Figure 46** and **Figure 47** we provide duration curves for regional curtailments for all three studies in the 2026 and 2035 study periods, respectively. The duration curves, which rank hourly curtailments from largest to smallest, show that the Integration Strategies scenario drastically reduces the magnitude and frequency of curtailments in most regions for both study periods. The opposite is true for the Limited Coordination scenario, which has more frequent and larger curtailments than the Baseline Case.

Figure 46: Curtailment Duration Curves for All 2026 Studies

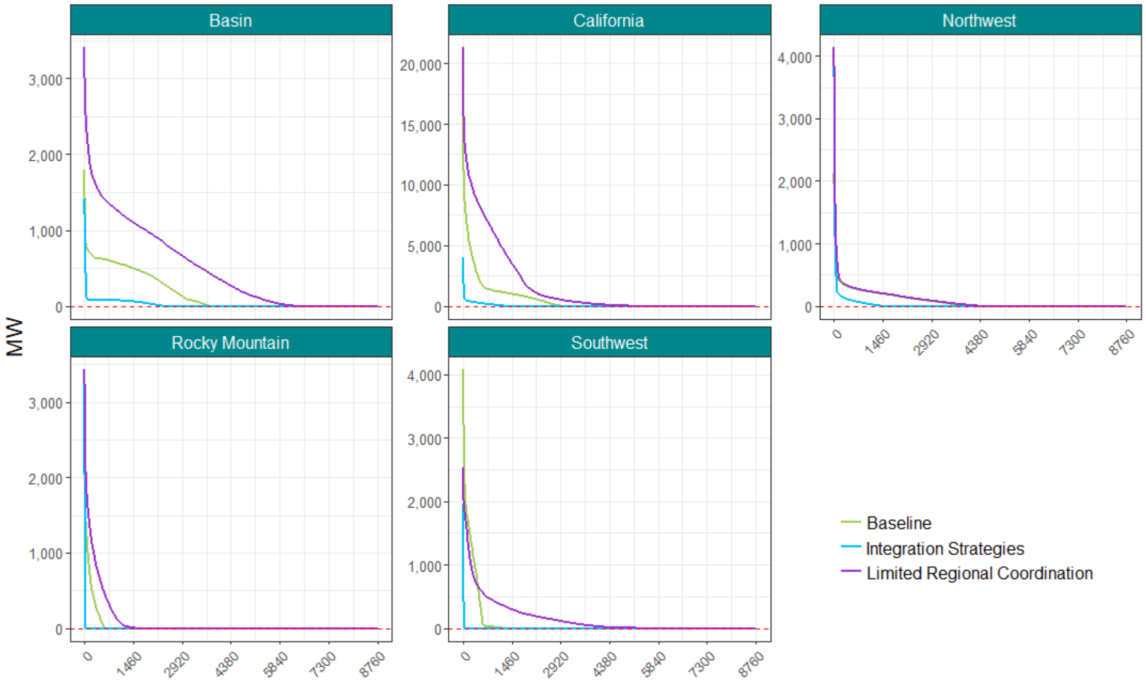
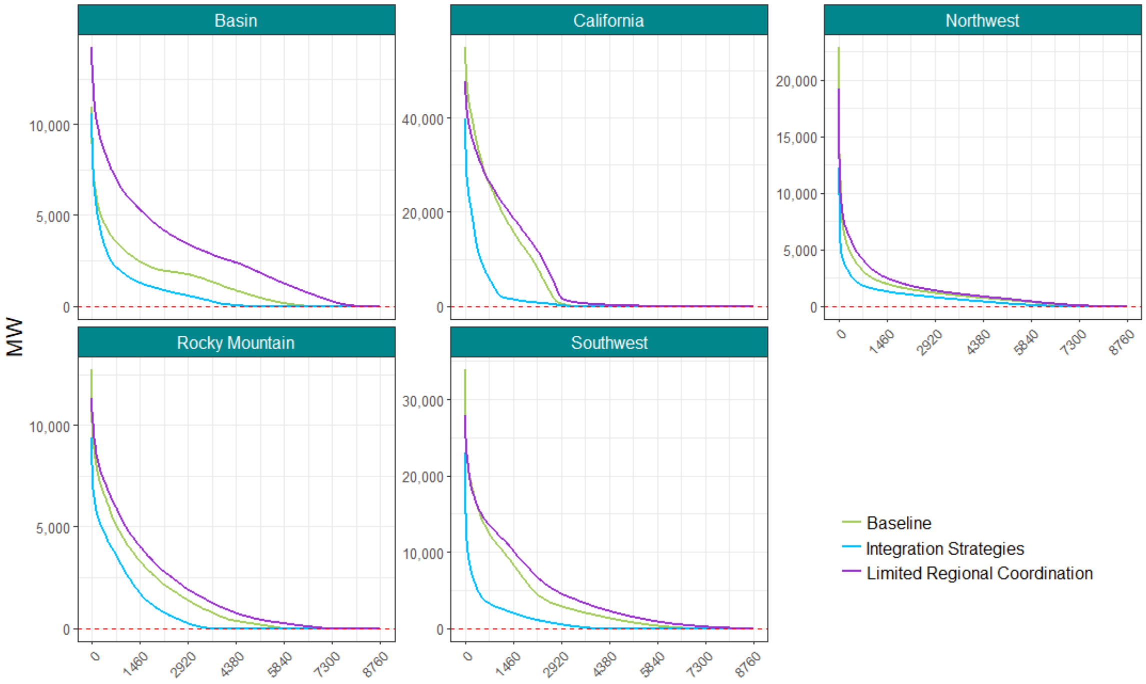


Figure 47: Curtailment Duration Curves for All 2035 Studies



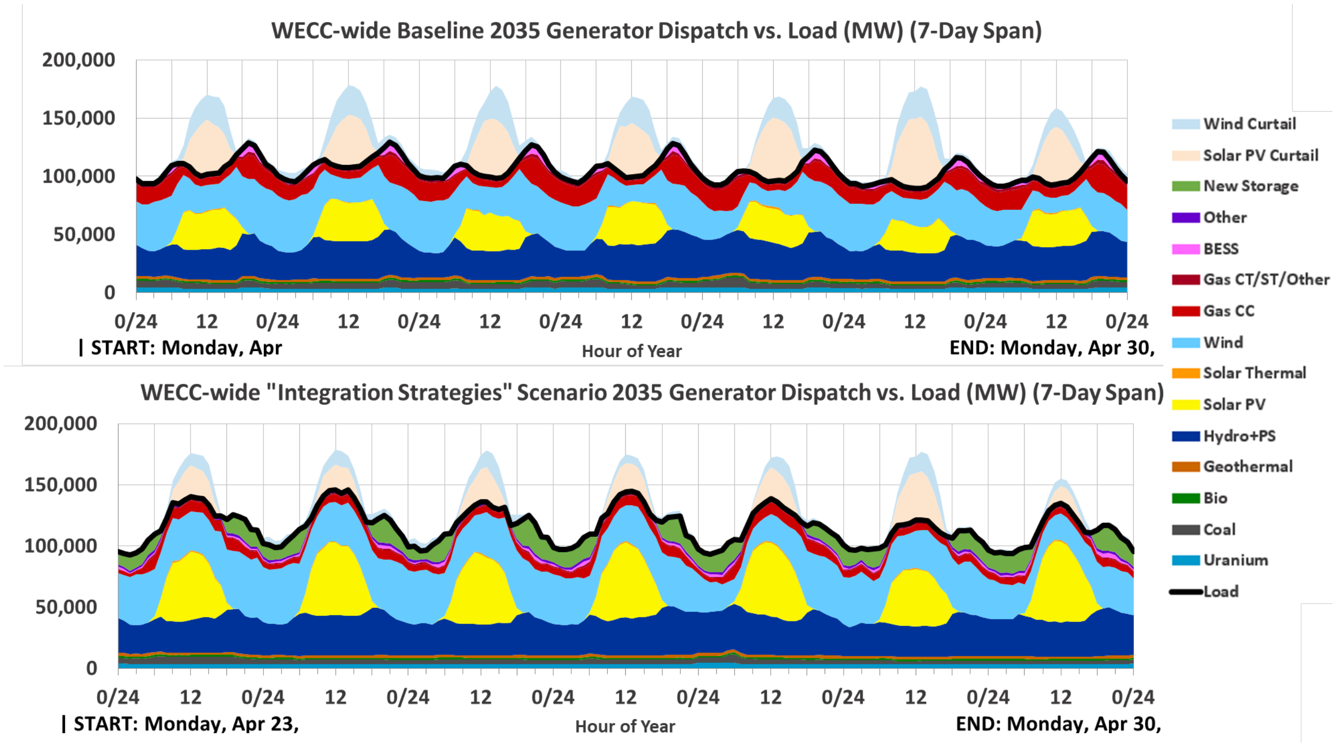
Flexibility solutions modeled in the Integration Strategies case helped to mitigate curtailments by adding mid-day load

In the Baseline Case, the majority of curtailments occur during the mid-day solar production period. The Integration Strategies scenario included large amounts of energy storage and new EV charging shapes, both of which add to mid-day load profiles (provided the storage is charging, which is an economic decision made by the model). The EV charging shapes were modeled as a fixed shape so they provided firm incremental mid-day load that was able to absorb renewable energy that would have otherwise been curtailed. The energy storage provided that same benefit but had the added ability to discharge generation in the afternoon and evening hours, which offset the need to dispatch thermal generators during that time.

Figure 48 shows 1-week of hourly operations in late April, 2035 for the Western system Baseline and Integration Strategies scenario. Several differences jump out, demonstrating the points above. The Baseline Case has more curtailments than the Integration Strategies case. This is partially due to the new load from mid-day EV charging and energy storage charging. The system load clearly peaks in the middle of the day in the Integration Strategies case, whereas in the

Baseline Case it peaks in the evening right after the sun goes down. Another obvious difference is the energy storage discharge in the Integration Strategies case: the discharge offsets largely combined-cycle output that ran in the Baseline Case.

Figure 48: WECC-wide system Operations for 1-week in Late April, 2035 - Baseline and Integration Strategies[38]



The Integration Strategies scenario achieved clean energy penetrations consistent with state energy policy

All three studies achieved clean energy penetrations consistent with the estimated clean energy target for the 2026 study period. However, the Limited Coordination scenario had the lowest penetration of the three, which suggests that meeting state policy goals will be more difficult if regional coordination (in the form of optimized markets) does not come to pass.

The finding above is exacerbated in 2035. The Limited Coordination scenario continues to fall short of policy targets, even shorter than the Baseline Case. The Integration Strategies scenario,

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[38] Load varies between the two study cases based on assumed changes to EV charging shapes and energy storage charging profiles. The gross retail load modeled is consistent across both scenarios.

on the other hand, does meet the policy target (exceeding the 64% target by 5%). This indicates that, in the long-run, market coordination *alone* is not sufficient to achieve the deep penetrations of renewables that are consistent with state policies. The system will require new renewable resources but also flexibility strategies similar to those considered in the Integration Strategies scenario, including new transmission, a diverse resource mix, new energy storage, and load management/participation.

7.0 PRODUCTION COSTS AND CARBON EMISSIONS

Production cost modeling used to evaluate the Baseline Case, Integration Strategies scenario, and Limited Regional Coordination scenario seeks to minimize system operational cost for the study year. These operational or "production costs" for the Western system are reported in **Table 26**.

Table 26: Study Case Production Cost Results

Study Case	WECC-wide		U.S. States	
	2026	2035	2026	2035
	Production Cost (B$)	Production Cost (B$)	Production Cost (B$)	Production Cost (B$)
Baseline	$11.1	$10.0	$9.6	$7.9
Integration Strategies	$10.7	$7.8	$9.2	$5.7
Limited Regional Coordination	$12.1	$11.3	$10.6	$9

Table 27 reports carbon emissions from the production cost simulations studies performed for the three study cases. These emissions may differ from those reported in Section 5.1 because the results are based on different simulation tools.

Table 27: Study Case Carbon Emission Results

Study Case	WECC-wide		U.S. States	
	2026	2035	2026	2035
	CO_2 Emissions (Million Metric Tons)	CO_2 Emissions (Million Metric Tons)	CO_2 Emissions (Million Metric Tons)	CO_2 Emissions (Million Metric Tons)
Baseline	161	134	132	94
Integration Strategies	159	108	131	69
Limited Regional Coordination	165	151	137	109

The WECC-wide emission results show that (1) emissions decline from 2026 to 2035 at a rate of 3 MMT per year in the Baseline Case; (2) the Integration Strategies scenario has 19% lower emissions than the Baseline Case by 2035 (because of its higher renewable penetration due to reduced curtailments); and (3) the Limited Regional Coordination case has 13% higher emissions than the Baseline Case because of its less efficient operations and transmission usage.

8.0 FINDINGS AND DISCUSSION

This Western Flexibility Assessment was a wide-ranging investigation, spanning 10 study years, four modeling tools, three cases, and innumerable data inputs and assumptions. The study focused on a Baseline Case, which reflected recent policy direction of Western states, along with two scenarios increasing and decreasing the flexibility of the power system. Using policy-adjusted resource portfolios, the study investigated flexibility challenges and potential solutions, while capturing the dynamic nature of interregional power flows and transmission-related aspects of system flexibility.

Some of the most important findings from this work include:

- Modeling results indicate that states can achieve near-term (2026) policy targets – at least a 33% west-wide clean energy target – without major changes to system flexibility. Western renewable curtailments were 3% in 2026, and system flexibility does not appear to be a significant technical barrier based on the various studies performed in this assessment.

- Study results also indicate that mid-2020 policy targets are achievable *without* a coordinated wholesale market in the West. However, not developing coordinated markets in the West reduces system flexibility and makes achievement of the clean energy targets less efficient. The cost, in the 2026 timeframe, of not developing coordinate markets amounts to increased curtailment (increasing from 3% to 11%), increased CO_2 emissions (2 MMT/year higher), and higher operational costs ($1B/year increase).

- As renewable penetrations increase in the 2030s, the flexibility cost of *not* having efficient wholesale markets becomes severe. In this timeframe, modeling indicates that continuing “status quo” levels of wholesale market coordination can cause curtailments to increase above a scenario in which regional markets do materialize. Not adding market coordination-based flexibility to the system causes a $1.3B/year increase in operational costs, and a 13% increase in CO_2 emissions. Coordinated wholesale electricity markets and full use of existing transmission infrastructure can be an effective way to increase a given system’s ability to integrate renewable resources.

- Long-term policies – which amount to a 64% clean energy target by 2035 – are difficult to achieve even with coordinated wholesale markets, however beneficial. The Baseline Case, which assumed a fully coordinated Western market, achieved a 2035 clean energy penetration of only 52%. This result suggests that, while market coordination does indeed provide *significant* operational and transmission efficiencies (as outlined above), additional flexibility-enhancing actions and investments are likely to be required to achieve clean energy targets in the 2030s.

- While this study did not consider all sources of system flexibility, the study considered adding flexibility in the form of new transmission, a more diverse resource mix, new energy storage, and managed charging of EVs. A scenario implementing these strategies achieved a clean energy penetration of 69%, which exceeded the 64% clean energy target. As compared to the Baseline Case, these flexibility strategies resulted in fewer curtailments (down to 9% from 20%), fewer CO_2 emissions (19% reduction) and lower system-wide operating costs (22% reduction).

- In the 2020s, modeling suggests that during times of overgeneration, regions will often sell excess power to neighboring regions, which reduces curtailments. However, in the 2030s, most regions have high penetrations of renewables, and as a result, there are fewer buyers for excess generation because there are frequent conditions in which multiple regions *simultaneously* have excess power. Ultimately, this observation suggests that in the near-term, regions can increase system flexibility by exporting excess energy to their neighbors, but in the long-run, opportunities for such exports may decline as deep renewable penetrations spread across the Western system.

- Interregional power transfers are likely to increase in the coming years. Additionally, results indicate that diurnal flow patterns may become the new norm. Certain transmission lines in the West historically have unidirectional flow patterns. However, in the 2020s and 2030s, results indicate that flows on many transmission lines in the West will be bidirectional, in great magnitudes, within a given day. Lines that once changed flow directions seasonally, or never, change flow directions hourly in the 2020s. Diurnal flow patterns are a significant departure from historical flow, and the trend is representative of the degree of interregional coordination and power exchange required to achieve high renewable penetrations in the West.

- The long-term policy targets assumed in this study created significant demand for new wind and solar generation across the West, amounting to 9 GW of incremental additions, per year, during the 2025-2035 timeframe. While this study did not include an independent assessment of land use, this level of deployment did not exceed assumed state-level technical potential limits.

- By 2035, based on the Baseline Case assumptions and modeling in this study, 80% of the West's energy needs could be provided by non-emitting resources – wind, solar, geothermal, hydro, and nuclear.

- The net amount of gas-fired generation, after considering retirements and additions, on the Western system does not change significantly during the study period. The Western resource mix is diverse throughout the study period. Like today, certain regions rely more heavily on certain technologies. However, during the study period, Western states rely on wind, solar, gas, hydro, and nuclear for most of their energy needs.

- The transmission analysis in this study, which focused on bulk-power system flows, indicates that the near-term system is robust and there is very little congestion on the system in the 2020s. If the system is used up to its reliability limits, and if economic-based congestion management is used to manage generator dispatch and system flows, the bulk power system can accommodate clean energy penetrations in line with 2026 state policy targets with minimal congestion.

- However, based on the resource siting assumptions used in this study, and the assumed transmission network, 2035 policy targets were difficult to achieve without modeling incremental transmission additions, even with economic-based congestion management. This result suggests that, in the long-run, the West might require significant incremental transmission upgrades to achieve policy goals.

- Targeted congestion analysis was performed for the Northwest region and based on the study results for the 2026 and 2035 nodal simulations, congestion in the Northwest grid is minimal. Result indicates that if the system is used up to its reliability limits and a flow- or market-based congestion management system is used to manage flows (such as what is assumed in our simulations), the bulk transmission interfaces in the

Northwest can handle significant renewable penetrations without facing severe congestion.

- This study included a deeper dive investigation into Northwest resource adequacy to answer core study questions and confirm the adequacy of the Baseline Case. Consistent with other works on the topic, absent any action, the Northwest region is likely to have a capacity shortage. Study results indicate that if no new resources are built, a 1,100 MW capacity shortage occurs no later than 2030. The magnitude of the capacity need varies based on assumptions about interim resource development.

- This study's evaluation of the Northwest region's adequacy need was highly sensitive to load assumptions. For 2027, the base studies assumed a 30,754 MW net peak demand for the region (adjusted for EE, EV charging, and distributed generation). A sensitivity study increasing this value by 14% to 35,015 MW significantly impacted the results. With this higher load forecast has a need for at least 4,000 MW of firm resources, in addition to the capacity supplied by 16,000 MW of incremental renewable resources required for public policy purposes.

- The firm capacity needs of the Northwest can be met with gas-fired generation; in addition to other resource options are also effective at meeting capacity needs in the Northwest region, including Montana wind, long-duration storage of at least 12-hours, and increased access to market purchases. Solar and short-duration storage (4-hr) have some capacity value, but this value diminishes as the size of region's capacity deficit increases.

- Results indicate that when Northwest generation shortages do occur, they are for extended periods and effect large amounts of load. In all studies, the average amount of lost load during curtailment events was more than 10 GW. In certain cases, load loss events last as long as 25 hours.

These findings are supported by the assumptions, modeling, and results described in the body of this report. There are several important questions not addressed in this work that are worthy of continued research, including:

- How do the resource build-outs impact power prices?

- How might power pricing and the value of ancillary services change as renewable penetration increases?
- Are flexibility solutions not considered in this study, such as lower operating limits on generators, equally as valuable as those solutions considered?
- What are the economic tradeoffs associated with the various flexibility solutions and is there an optimal portfolio of flexible resources (including transmission and demand-side actions)?
- To what degree might this study's results change if a more flexible scheduling and dispatch behavior was assumed for renewables?
- Given the apparent need for intra- and inter-regional power exchange, what role might transmission play in that picture and how does it perform relative to other flexibility measures? For instance, might expanded transmission ties with the Plains states be a flexibility solution worth considering?

This exploratory study was not designed to lead to any specific policy recommendations. It was an informational effort addressing long-term system flexibility under futures in which state policy goals are achieved. However, in addition to the study findings, above, several recurring and policy-oriented themes appeared.

- While today's system is not as balkanized as it once was, thanks to the Western EIM and joint-dispatch, allowing the full use of the transmission system, with efficient price signals and congestion management, can help increase system flexibility. This finding is consistent with many other recent studies on the topic. In the short-term, operational modeling suggests policy achievement is possible without more coordinated markets. However, in the long-term, absent coordinated markets, achieving renewable penetrations in line with state policies appears to be difficult, in terms of operational cost and efficiency.

- The results for the Northwest adequacy portion of this assessment were highly sensitive to load forecast and resource-built assumptions. This finding points to the importance of load forecasting in the Northwest.

- This study attempted to use historical path flow data collected by WECC to learn about how system power flows are changing over time. The most recent data available was 2012, which limited the usefulness of the analysis. WECC and its members should make more recent data readily available to help carry out its reliability mission in the West.

- The economic curtailment of renewables will be a tool that system operators use often in the coming decades. Operators will continue to use this solution frequently, even with aggressive shifting of loads and investments in energy storage. PPAs, which are one of the most important contracts that ensure state policies are met, need to consider and allow for flexible operations of renewable resources. At a minimum, the costs of this solution need to be considered alongside other flexibility tools.

- Targeted transmission upgrades were an important source of flexibility in this study. Often times transmission is ignored as a flexibility solution. However, the tool helps to ensure that congestion-driven inflexibility is minimized or eliminated.

- Sources of system flexibility that proved effective in this study are proxies for similar flexibility solutions not studied. For example, this study explored the “ideal” management of EV charging loads, but achieving the same result is possible with other programs that incent customer load-shifting behavior, such as time-of-use rates. Another example is storage: this study focused on 4-hour lithium-ion battery storage, and 12-hour pumped storage. Other existing or future storage technologies may be just as effective.

- Exporting surplus power to neighboring states is, at times, a viable flexibility strategy for states seeking to increase their renewable penetration. However, as neighboring areas join in and begin to increase *their* renewable penetration to significant levels, the ability to export excess power diminishes for both states since they both have more frequent periods of excess power. The Baseline Case study results suggest this phenomena may begin to impact the West in the 2030 timeframe. Given that the scenario causes a once promising flexibility source – exports – to “dry up”, sub-regional studies, including those performed at a state or utility-level, should consider representing policy requirements of neighboring states and regions. This work demonstrates how operational conditions in neighboring regions can impact an individual state’s policy and investment decisions.

9.0 TECHNICAL APPENDIX

9.1 Prior Work

This effort is one of many studies investigating system flexibility and renewable integration. However, because of its timing, it is one of the first efforts to consider the implications of the array of recently implemented and project state policies. Relevant studies are summarized in **Table 28**.

Table 28: Relevant Studies

Report	Author	Relevance
Western Interconnection Flexibility Assessment (2015)	NREL and E3	Region-by-region assessment considering flexibility implications of high renewables future; stochastic representation of variable generation
Resource Adequacy in the Northwest (2019)	E3	Examines expanded Northwest region and its capacity challenges in 2018, 2030, and 2050 under varying decarbonization levels
Pacific Northwest Low Carbon Scenarios (2017-18)	E3	Multi-sector evaluation, focused on the Northwest region, investigating implications of achieving carbon emission goals using least-cost planning methods
Western Wind and Solar Integration Study (2010-14)	NREL	A three-phase study investigating the ability to integrate large amounts of wind and solar into the Western grid, considering a number of new perspectives including wear-and-tear on the thermal fleet, and transmission reliability
Low Carbon Grid Study (2014)	NREL	California-focuses study looking into ways to achieve deep reductions in greenhouse gas emissions, also considering system flexibility and the impacts of drought.

While not an exhaustive list, these efforts address topics considered in this analysis. While a study-to-study comparison across these efforts is not in the scope of this report, recognize that each of these works attempts to address the challenge of renewable integration from a unique perspective, study method, or footprint. Further, a number of these efforts led to conclusions that are similar to what is ultimately drawn from this project.

9.2 Modeling Tools

The study's multi-step modeling approach utilized four main software tools. Each is briefly described below.

- **Aurora™ (v13.3.1011)** – utility-grade production cost and capacity expansion model from Energy Exemplar (formerly EPIS). The tool is commonly used to develop utility integrated resource plans and has the capability to run as a security-constrained economic dispatch model in both zonal and nodal format. It also has a long-term capacity expansion module that can be used to evaluate policy impacts, new market rules, and changes in market fundamentals. The long-term capacity expansion mode can be used to forecast the addition and retirement of resources based on market economics and numerous constraints, such as carbon caps (or price) and RPS requirements. The tool is commonly used in industry, especially in the Northwest. The NWPCC, BPA, Puget Sound Energy, Portland General Electric, public utility districts, PacifiCorp, among other utilities, use this software for the purposes of forecasting prices, developing resource plans, and evaluating policy issues.
- **GENESYS (v15)** – The Generation Evaluation System (GENESYS) is a stochastic/Monte Carlo model that simulates the operation of the Northwest power system to determine the adequacy of the region's power supply. It is used by the NWPCC, BPA, and other regional stakeholders for numerous purposes, including adequacy assessments, hydro flow studies, and economic analysis of hydro dispatch changes. The tool is an hourly simulation model that captures statistical variations in temperature/load, river flows, wind generation, solar generation, and generator forced outages and unique operational constraints of the Northwest hydro system. The data and the model are maintained by the NWPCC, and the tool is unique because it accurately represents hydro system constraints (e.g., environmental requirements), properly accounting for the sustained peaking capability (2-10 hours) of the system under varying hydro conditions. The tool is the ideal adequacy evaluation model for the Northwest system because it is the most accurate representation of the hydro systems ability to contribute to extended hour-peaking needs. It captures 80-years of hydro and temperature data, and also includes sampling of wind and solar. A GENESYS study relies on more than 5,000

simulations to determine loss of load probability (LOLP) and loss of load expectation (LOLE) metrics.[39]

- **GridView™ (v10.2.67, 2019-07-30)** – Nodal production cost model tool which simulates the hour-to-hour system operation subject to real-world constraints such as transmission limits, generation operating characteristics, and load levels. A highly detailed transmission system is represented in the model, including substations, transformers, and transmission lines. For this study, the tool was used primarily to assess hourly operations, transmission flows, and ability to deliver renewables consistent with policy goals.

- **PowerWorld™ Simulator (Version 20 build 483)** – Full AC power flow simulator and steady-state contingency analysis tool. Results were used to evaluate the reliability of the bulk power system under high load and high renewable penetration stressed conditions based on the results of the nodal production cost model simulations.

9.3 Model Set-up

The models used in this assessment can be set-up in varying ways. This short section outlines how we set-up the four tools used in this assessment.

AURORA

- The base dataset was the NWPCC Mid-Term AURORA zonal database dated January 3, 2019, with updates outside of the Northwest region sourced from the AURORA "US_Canada 2018_v3" Data Package dated October 2018, along with other data sources such as the Energy Information Administration (EIA) and the Western Electricity Coordinating Council (WECC).
- New resource additions were available for every state-region combination as well as potential out-of-state resource options, all of which considered:
    - Fixed cost (capital cost, property tax, and insurance) and fixed O&M cost trajectories for the entire study period based on location.
    - Assumed capacity values by generation type, location, and development status.

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[39] The NWPCC is undertaking a redevelopment of the GENESYS model and this model was not available for this study based on its timing requirements.

- Transmission constraints represented between all regions.
- Modeling included planning reserve margin (PRM), firm imports, firm exports, and operating reserve requirement constraints for each region.
- Operational simulation sampled every chronological hour in one week of every month in the study period.
- AURORA's Minimize Cost Mixed-integer program (MIP) was utilized to determine the mix of resources (both existing and new build options) over the study period that satisfied all energy, policy, and demand requirements while minimizing the system cost.
- The capital expansion modeling included retirement logic that could advance generators' retirement dates if their operational cost exceeded the market price at their location.

GENESYS (GENeration Evaluation SYStem Model)

- The base dataset was the preliminary NWPCC 2024 Median GENESYS model dated March 27, 2019, applicable only to the Pacific Northwest.
- Contractual imports and exports were provided by BPA to reflect contracts in the BPA 2018 BPA White Book.
- Modeling used 69 historical years (1949-2017) of correlated hourly Columbia Gorge wind and streamflow data.[40]
- Hourly solar production based on 12 historical years. The software randomly selected from these sets of hourly data for each simulation.
- Transmission constraint modeling reflected sub-regional transmission constraints in Northwest region footprint.[41]
- Hydro assumptions reflected the Northwest hydro's real-life 2-, 4-, and 10-hour sustaining peaking capabilities based on non-power related constraints such as those to protect, mitigate, and enhance fish and wildlife populations that could be threatened by the hydroelectric system.
- Load forecasts based on 69 separate hourly shapes, each representing peak load and energy variability for years 1949-2017.

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[40] The model includes 20 different temperature-capacity factor correlated versions of the historical Columbia Gorge wind data. The software randomly selected from these sets of hourly data for each simulation

[41] West- and east-side of the NWPCC footprint (PNW West and PNW East), with east-to-west flow limited to 17,000 MW and flow in the opposite direction limited to 12,000 MW, and imports from Canada & California limited to 3,400 MW

GridView™

- The base dataset was the CAISO 2028 Default Portfolio PCM dated February 2, 2019, which was built from the WECC 2028 Anchor Data Set (ADS) production cost model.
- Transmission constrained modeled at the nodal resolution, capturing all constraints above 200 kV, with select bulk electric system (BES) elements below 200 kV.
- Wind and solar generation modeled with hourly generation profiles based on National Renewable Energy Laboratory (NREL) weather and simulated output data.
- Ancillary services and contingency reserves modeled with varying levels of granularity, including BAA, reserve sharing group, and the region.
- Used 7-day Look Ahead and Multi-Interval Optimization (MIO) logic to improve simulated dispatch, especially for storage and hydro resources.

PowerWorld™

- The base dataset was the WECC 2028 Heavy Summer 1 ADS Planning Case as of February 28, 2019.
- Monitored elements included everything with voltages at or above 200kV, including transformers with a high-side winding voltage at or above 200kV.
- Contingency analysis included all P0 and P1 contingencies involving the above-mentioned monitored elements and evaluated violations consistent with reliability standards adopted by the North American Electric Reliability Corporation (NERC) Transmission System Planning Performance Requirements and Transmission System Planning Performance WECC Regional Criterion.[42]

We used the model set-ups described above for both the Baseline Case and the scenario cases.

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[42] NERC TPL-001-4: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission%20System%20Planning%20Performance%20Requirements&jurisdiction=United%20States

WECC Regional Criterion: https://www.wecc.biz/Reliability/WECC-0100%20TPL-001-WECC-CRT-3%20-%20Posting%202%20-%20for%20redline%204-29-2015.doc

9.4 Hydro Modeling

This study leveraged the NWPPC's hydro modeling methodologies in the capital expansion, GENESYS, and production cost modeling. The following sub-sections summarize these methodologies, by model.

Hydro in the GENESYS modeling

The hydro data came from the preliminary NWPCC 2024 Median GENESYS model dated March 27, 2019. The sources listed below provide background material regarding the hydro modeling in GENESYS.

- NWPCC GENESYS webpage.[43]
- NWPCC Background on GENESYS model.[44]
- The GENESYS Northwest Model, BPA Hydro Modeling Conference, February 21-22, 2012.[45]

The GENESYS simulation considers both non-time dependent and time dependent hydro data (shown in **Table 29**) in its security constrained economic dispatch optimization in order to simulate hydro operation which takes into account the economics of the NWPCC generation as well as constraints intended to protect, mitigate and enhance fish and wildlife populations that could be threatened by the hydroelectric system.

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[43] https://www.nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/genesys-–-generation-evaluation-system-model

[44] https://www.nwcouncil.org/sites/default/files/p1_219.pdf

[45] https://www.bpa.gov/Doing%20Business/TechnologyInnovation/ConferencesReservoirSystemModeling/5_3_Fazio.pdf

Table 29. GENESYS Hydro Data

Non-time dependent hydro data	Time dependent hydro data
• Physical top and bottom of reservoir • Minimum and maximum turbine flow • Plant data tables ○ Max flow vs. storage ○ Max generation vs. head ○ Elevation vs. storage ○ Tail water elevation vs. outflow ○ Power factor vs. load	• Natural stream flows – 80 years of historical data • Rule curves • Min and max outflow • Min and max elevation • Bypass spill

Hydro in the capital expansion and production cost modeling

The hydro data came from the NWPCC Mid-Term AURORA zonal database, dated January 3, 2019, which included 80 different sets of monthly hydro energy budgets and the on- and off-peak maximum and minimum output constraints. Each of the 80 sets corresponded with the historical hydro conditions in years 1929 through 2008 and the bounds of the hydro dispatch determined by a GENESYS simulation. The capital expansion and production cost modeling utilized the monthly hydro energy budgets and the on- and off-peak maximum and minimum hydro output constraints determined by GENESYS using the hydro conditions in the year 2000. The process for developing and using these hydro constraint assumptions is summarized below.

1. NWPCC fed consistent load, conservation (energy efficiency), wind and solar generation, and thermal resource data into its GENESYS and AURORA, as shown in **Figure 49**.
2. The GENESYS simulation is run and comes up with 80 different variants of hydro operation.
3. The monthly hydro energy budgets and the on- and off-peak maximum and minimum hydro outputs of each variant of hydro operations is extracted from GENESYS and fed into the AURORA simulation, as shown in **Figure 50.** This study used the hydro operations corresponding with the hydro conditions of the year 2000.

4. The AUROR simulation adheres to the monthly hydro energy budgets and the on- and off-peak maximum and minimum hydro output constraints in order to mimic the constrained dispatch produced by GENESYS, as shown in **Figure 51**.

Figure 49: NWPCC Methods for AURORA-GENESYS Interface[46]

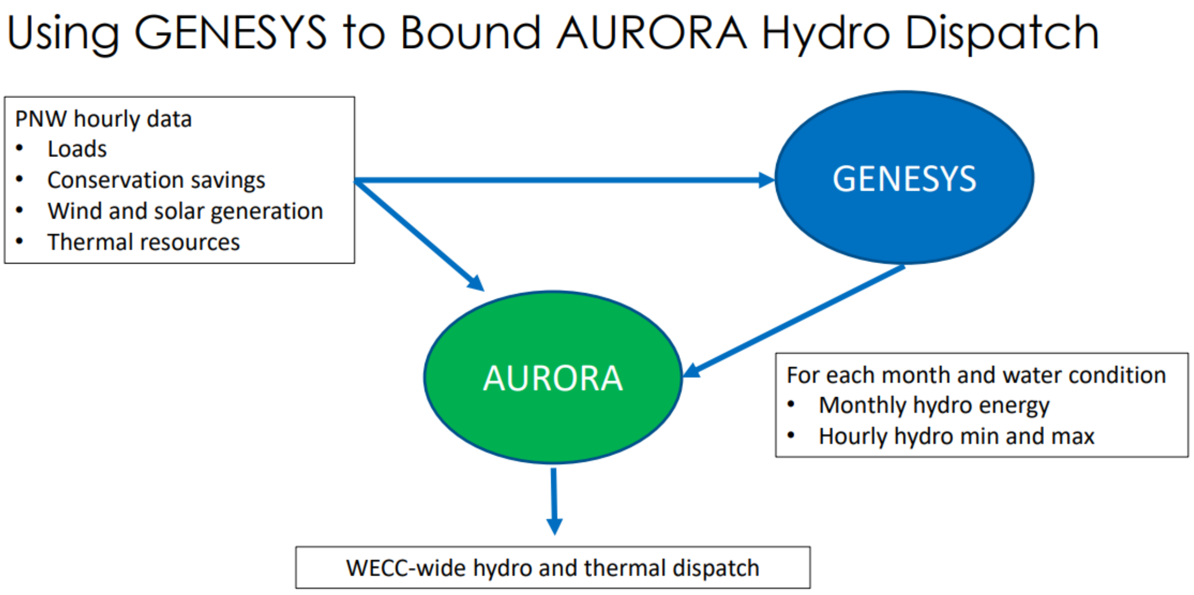
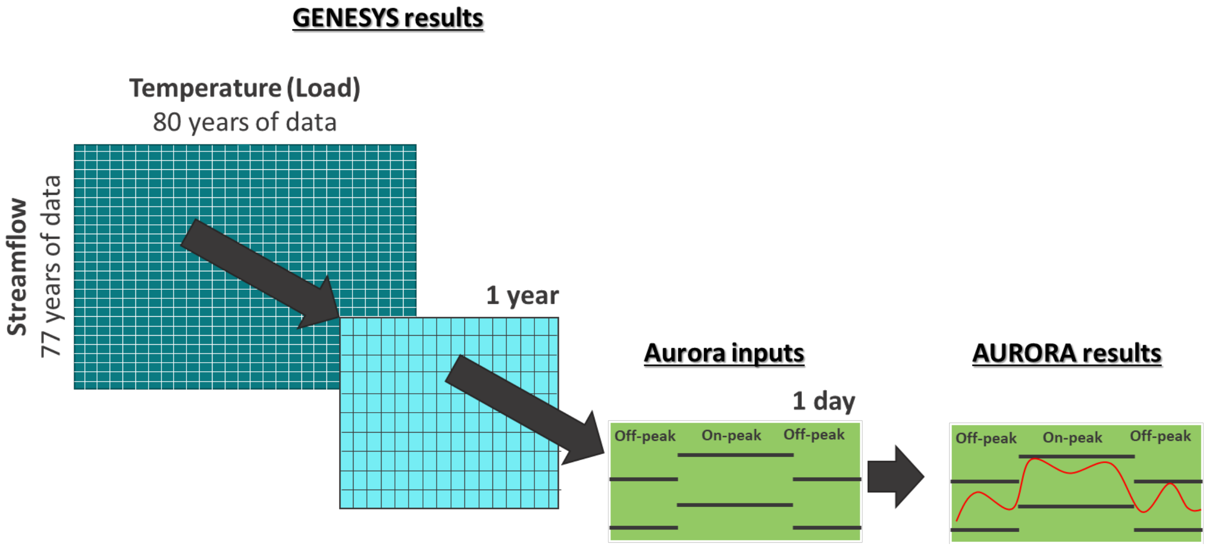


Figure 50: Extracting hydro operation constraints from GENESYS for AURORA simulation



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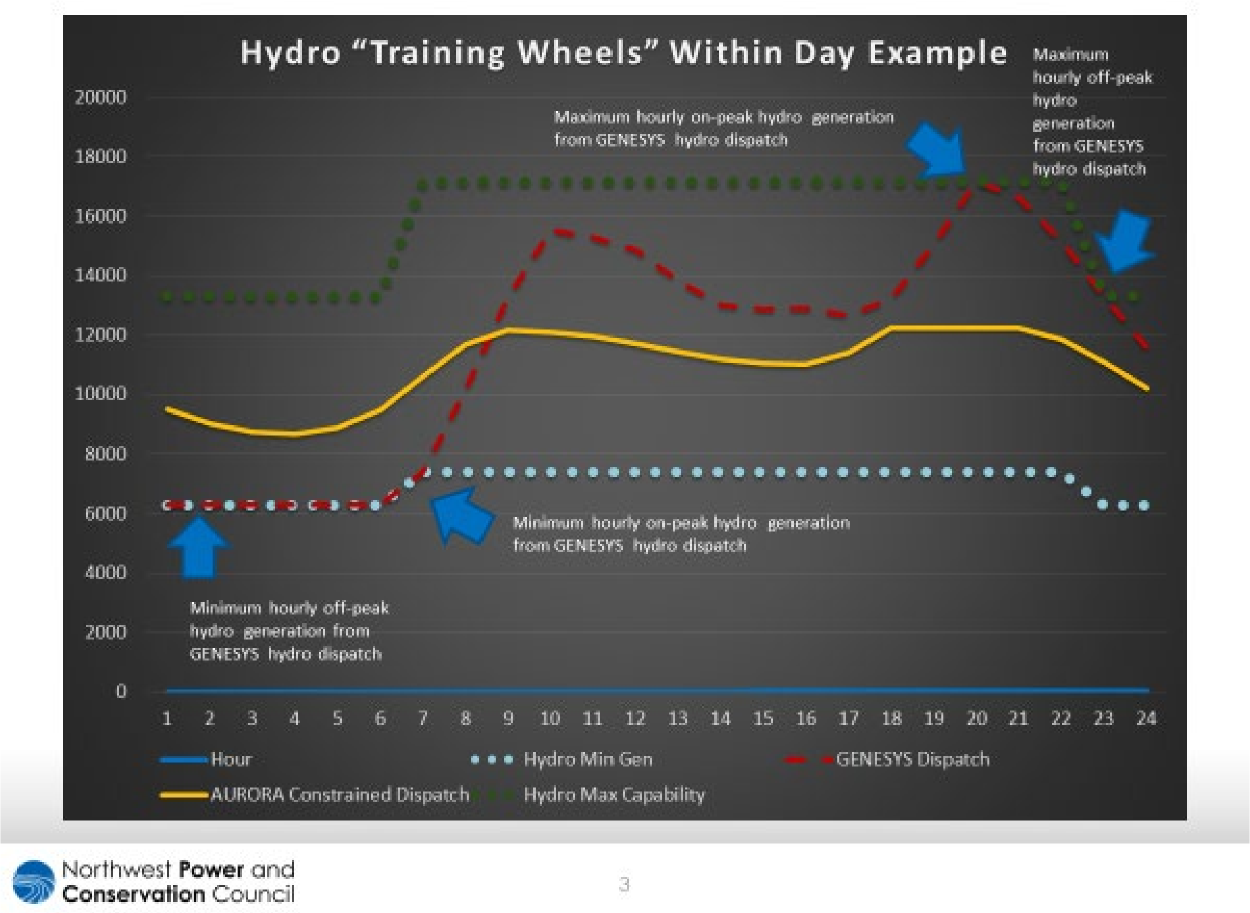
[46] NWPCC. Source is available here: https://www.wecc.biz/Administrative/Adequacy%20Briefing_J%20Fazio.pdf

Figure 51. Illustrating How On- and Off-Peak minimum and maximum hydro output extracted from GENESYS simulation provides operating bounds for the AURORA simulation[47]



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[47] Presented in NWPCC System Analysis Advisory Committee (SAAC) meeting on April 11, 2019: https://www.nwcouncil.org/meeting/system-analysis-advisory-committee-modeling-techniques-and-assumptions-aurora-april-11-2019

9.5 Policy Constraints

RPS & Clean Energy Policies

The study represented a broad range of RPS & clean energy policies, from those recently enacted, to those proposed or announced, to potential clean energy requirements driven by procurement trends and voluntary targets in some areas. **Table 30** provides a summary of the assumed RPS and clean targets, including the reasonably assumed trajectory to meet the deadlines enacted by each state. More details regarding these policies are described below. Based on these policies, renewable energy generally included wind, solar, bio-fuel, and geothermal power throughout the system, but also included nuclear and hydro power serving Washington and Arizona.

Table 30. Assumed RPS/Clean Energy Target by State

<table>
<tr><th rowspan="2"></th><th rowspan="2">Year</th><th>California</th><th colspan="6">Northwest</th><th colspan="2">Intermountain</th><th colspan="2">Rockies</th><th colspan="2">Southwest</th></tr>
<tr><th>CA</th><th colspan="2">OR</th><th colspan="2">WA</th><th>ID</th><th>MT</th><th>NV</th><th>UT</th><th>CO</th><th>WY</th><th>AZ</th><th>NM</th></tr>
<tr><td></td><td>2020</td><td>33%</td><td colspan="2">20%</td><td colspan="2">15%</td><td>4%</td><td>15%</td><td>22%</td><td>0%</td><td>30%</td><td>0%</td><td>10%</td><td>20%</td></tr>
<tr><td></td><td>2021</td><td>33%</td><td colspan="2">20%</td><td colspan="2">15%</td><td>8%</td><td>15%</td><td>22%</td><td>0%</td><td>30%</td><td>0%</td><td>11%</td><td>20%</td></tr>
<tr><td></td><td>2022</td><td>33%</td><td colspan="2">20%</td><td colspan="2">15%</td><td>12%</td><td>15%</td><td>26%</td><td>0%</td><td>30%</td><td>0%</td><td>12%</td><td>20%</td></tr>
<tr><td></td><td>2023</td><td>33%</td><td colspan="2">20%</td><td colspan="2">20%</td><td>16%</td><td>15%</td><td>26%</td><td>0%</td><td>32%</td><td>0%</td><td>13%</td><td>20%</td></tr>
<tr><td></td><td>2024</td><td>44%</td><td colspan="2">20%</td><td colspan="2">25%</td><td>20%</td><td>15%</td><td>34%</td><td>0%</td><td>36%</td><td>0%</td><td>14%</td><td>20%</td></tr>
<tr><td></td><td>2025</td><td>44%</td><td colspan="2">27%</td><td colspan="2">30%</td><td>24%</td><td>15%</td><td>34%</td><td>0%</td><td>40%</td><td>0%</td><td>15%</td><td>25%</td></tr>
<tr><td rowspan="10">Study Period</td><td>2026</td><td>44%</td><td>27%</td><td rowspan="10">Cap and Invest</td><td>35%</td><td rowspan="10">Carbon Cap and 80% RPS by 2035</td><td>28%</td><td>15%</td><td>34%</td><td>0%</td><td>44%</td><td>0%</td><td>15%</td><td>30%</td></tr>
<tr><td>2027</td><td>52%</td><td>27%</td><td>40%</td><td>32%</td><td>15%</td><td>42%</td><td>0%</td><td>48%</td><td>0%</td><td>20%</td><td>35%</td></tr>
<tr><td>2028</td><td>52%</td><td>27%</td><td>45%</td><td>36%</td><td>15%</td><td>42%</td><td>0%</td><td>52%</td><td>0%</td><td>25%</td><td>40%</td></tr>
<tr><td>2029</td><td>52%</td><td>27%</td><td>50%</td><td>40%</td><td>15%</td><td>42%</td><td>0%</td><td>56%</td><td>0%</td><td>30%</td><td>45%</td></tr>
<tr><td>2030</td><td>60%</td><td>35%</td><td>55%</td><td>44%</td><td>15%</td><td>50%</td><td>0%</td><td>60%</td><td>0%</td><td>35%</td><td>50%</td></tr>
<tr><td>2031</td><td>63%</td><td>35%</td><td>60%</td><td>48%</td><td>15%</td><td>50%</td><td>0%</td><td>64%</td><td>0%</td><td>40%</td><td>53%</td></tr>
<tr><td>2032</td><td>66%</td><td>35%</td><td>65%</td><td>52%</td><td>15%</td><td>50%</td><td>0%</td><td>68%</td><td>0%</td><td>45%</td><td>56%</td></tr>
<tr><td>2033</td><td>69%</td><td>35%</td><td>70%</td><td>56%</td><td>15%</td><td>50%</td><td>0%</td><td>72%</td><td>0%</td><td>50%</td><td>59%</td></tr>
<tr><td>2034</td><td>72%</td><td>35%</td><td>75%</td><td>60%</td><td>15%</td><td>50%</td><td>0%</td><td>76%</td><td>0%</td><td>55%</td><td>62%</td></tr>
<tr><td>2035</td><td>75%</td><td>45%</td><td>80%</td><td>64%</td><td>15%</td><td>50%</td><td>0%</td><td>80%</td><td>0%</td><td>60%</td><td>65%</td></tr>
</table>

- The study represented very recently enacted RPS/clean energy policies in Washington, Colorado, New Mexico, and Nevada.[48] Nuclear and hydro generation counted toward the Washington clean energy standard.
- The Baseline Case assumes that California, Oregon, and Washington all have carbon cap-and-trade programs (by 2026) with a common allowance trading platform.
    - The assumed carbon price in the study was based on the 42 MMT case of the CPUC RESOLVE 2018 IRP Model, starting at $24.76/Ton and growing to $43.08/Ton (nominal dollars) from 2026 through 2035.
- While Arizona and Idaho do not have major incremental energy policies, procurement trends, and voluntary targets by utilities in those states prompted us to assume incremental clean energy requirements for this study. In Arizona, we assumed that nuclear generation would count toward a potentially future clean energy standard.
- The study assumed California and Montana policies at their enacted levels, with no incremental requirements assumed.[49]
- Special notes, by state:
    - CO: Assume Governor Polis goes 100% RPS by 2040; Xcel committed to 100% by 2050.
    - NM: 50 percent by 2030 and 80 percent by 2040.
    - AZ:
        - AZ Energy Modernization Plan (ACC), includes Palo Verde in plan.
        - SRP RPS is 20%, include hydro, then match with rest of AZ for years with >20%.
    - WA: Include Nuclear and part of Northwest hydro.
    - CA: Look at CA clean energy standard; will add some type of electrification.
    - OR: 50% by 2040 for large utilities; the state's two investor-owned utilities must phase out coal generation by 2035.
    - ID: 100% by 2045, assumed incremental 4% each year from 2020 to 2035.

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[48] Notably, these policies were not yet final when the study work was performed. As such, the policy targets are only approximate to what was ultimately legislated in these states.

[49] No mandatory RPS or clean energy policy existed in Utah and Wyoming, so the study did not impose incremental requirements for load in these states. Utah does have a mandatory RPS, but it is only mandatory if cost effective, thus no RPS was modeled.

Nuclear and Hydro Applicability to Washington RPS

- 63% of Columbia Generating Station output was assumed to contribute toward the Washington RPS. This was based on the ratio of BPA load in Washington to the total BPA load in Washington and Oregon, as a proxy for how much of the plant's output serves Washington load.
- Hydro located in Washington and within the territories of Bonneville Power Administration, Chelan County PUD, Douglas County PUD, Grant County PUD, and Seattle City Light territories was assumed to only contribute to those territories' RPS.

GHG Reduction Policy

- Oregon and Washington were assumed to join California's cap-and-trade program, which was represented by (1) a carbon emissions price on thermal generation in California, Oregon, and Washington and (2) a carbon adder wheeling charge on flows into the combined footprint of California, Oregon, and Washington as illustrated in **Figure 52**.
- Assumptions were based on the CEC RESOLVE 2018 IRP Model (updated September 7, 2017) and "42mmt_Ref_20181101_2017_IEPR" Case and are shown in **Table 31**.

Figure 52. Illustration of Carbon Adder Wheeling Charge in GHG Reduction Policy Modeling

Table 31. Carbon Emission Price and Carbon Adder Wheeling Charge Assumptions, by Year

Assumption	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Carbon Emission Price (2019$/Ton)	23.02	24.22	25.49	26.83	28.24	29.72	31.27	32.91	34.63	36.44
Full Carbon Adder Wheel (2019$/MWh)	9.83	10.34	10.89	11.46	12.06	12.69	13.36	14.06	14.79	15.57

9.6 Forecasting Load and Behind-the-Meter Load Modifiers

Table 32 summarizes the data sources used for forecasting the growth of unadjusted demand, energy efficiency (EE), behind-the-meter (BTM) solar PV generation, and electric vehicle (EV) demand.

Table 32. Sources for forecasting load and behind-the-meter load modifiers

Forecast	Northwest	California	Rest of the West
Unadjusted Demand	NWPCC 7th Power Plan	CEC 2018 IEPR Update (Mid-Baseline), IOU-specific hourly shapes	WECC Loads and Resources Data (circa 2018)
Energy efficiency (EE)	NWPCC 7th Power Plan (reduced to WECC L&R forecast to match 7th Power Plan “Net Conservation” Load)	CEC 2018 IEPR Update (Mid-AAEE), IOU-specific AAEE hourly shapes	WECC L&R Data (circa 2018)
BTM Solar PV (DG)	NREL REEDS State-level forecast, spread to area-level based on area share of states	IOU’s: CEC 2018 IEPR Update (Mid-AAPV) Non-IOU’s: NREL REEDS State-level forecast (less IOU’s load share) based on area share of states	NREL REEDS State-level forecast spread to area-level based on area share of states
Electric Vehicle (EV)	NWPCC 7th Power Plan Impact of Electric vehicles (EV or PHEV) – High Forecast	CEC 2018 IEPR Update High Forecast of EV Electricity Demand	AEO 2019 Mountain Region PEV-driven energy demand, less Idaho EV per NWPCC 7th Power Plan

Growth of Unadjusted Demand and Energy Efficiency

The unadjusted, gross load forecast is summarized in **Table 33** and **Table 34**. The energy efficiency adjustments applied on top of the demand forecast is provided in **Table 35.**

Table 33. Forecasted Annual Peak Demand Before Adjustments

Peak Demand (MW)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	69,488	72,303	76,734	1.0%
Northwest	34,093	34,849	35,791	0.5%
Basin	11,038	11,278	11,542	0.4%
Rocky Mountain	13,265	13,936	14,777	1.1%
Southwest	31,548	33,406	35,676	1.2%
Total	**153,425**	**159,700**	**165,769**	**0.8%**

(Intentionally left blank)

Table 34. Forecasted Annual Energy Prior to Adjustments

Energy (GWh)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	339,909	353,082	374,804	1.0%
Northwest	195,654	199,976	205,276	0.5%
Basin	61,838	63,005	64,195	0.4%
Rocky Mountain	75,516	79,636	87,695	1.2%
Southwest	140,046	146,634	154,841	1.0%
Total	**812,963**	**842,334**	**883,811**	**0.8%**
Average Hourly Load (MWa)	**2026**	**2030**	**2035**	**CAGR (%/yr) 2026-2035**
California	38,802	40,306	42,786	1.0%
Northwest	22,335	22,828	23,433	0.5%
Basin	7,059	7,192	7,328	0.4%
Rocky Mountain	8,621	9,091	10,011	1.2%
Southwest	15,987	16,739	17,676	1.0%
Total	**92,804**	**96,157**	**100,892**	**0.8%**

Table 35. Forecasted Energy Efficiency Adjustments

Additional Energy Efficiency (MWa)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	2,174	3,207	4,623	7.8%
Northwest	3,096	3,642	3,328	0.7%
Basin	0	0	0	0.0%
Rocky Mountain	0	0	0	0.0%
Southwest	0	0	0	0.0%
Total	**5,270**	**6,849**	**7,951**	**4.2%**

Growth of Distributed Generation

Table 36 summarizes the forecasted growth of DG and **Table 37** shows that growth compared with the forecasted load energy.

Table 36. Forecasted distributed generation (BTM Solar PV)

BTM Solar PV (MWa)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	3,465	4,221	5,244	4.2%
Northwest	95	153	250	10.1%
Basin	196	254	298	4.3%
Rocky Mountain	138	166	199	3.7%
Southwest	463	531	595	2.5%
Total	**4,358**	**5,324**	**6,585**	**4.2%**

Table 37. Forecasted distributed generation (BTM Solar PV) as a percentage of load energy

BTM Solar PV energy as a % of load energy	2026	2030	2035	CAGR (%/yr) 2026-2035
California	9%	10%	12%	3.22%
Northwest	0%	1%	1%	9.63%
Basin	3%	4%	4%	3.89%
Rocky Mountain	2%	2%	2%	2.19%
Southwest	3%	3%	3%	1.52%
Total	**5%**	**6%**	**7%**	**3.35%**

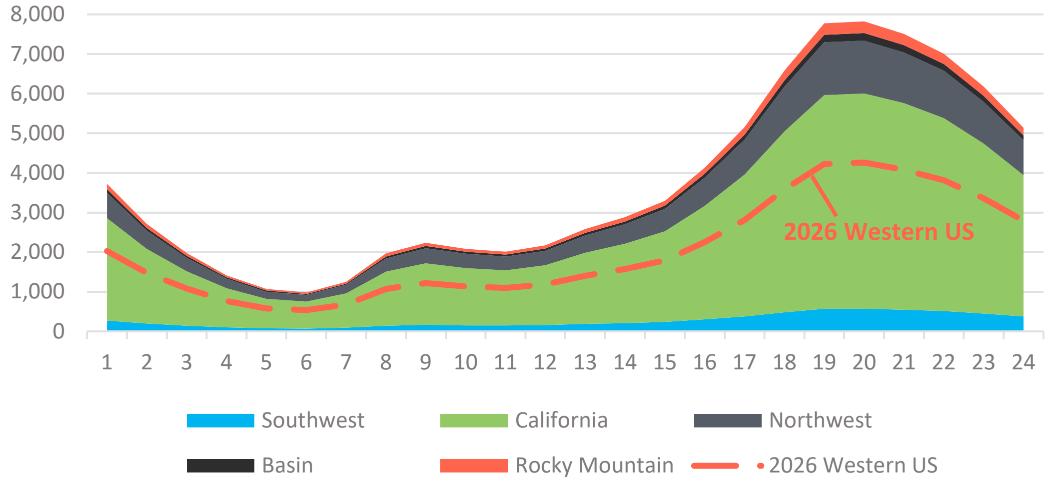
Growth of Electric Vehicle Demand

- **Table 38** summarizes the cumulative electric vehicle (EV) population growth.
- EV hourly charging shapes had weekday- and weekend-specific profile developed by the California Energy Commission (CEC) and NREL using the Electric Vehicle Infrastructure Projection Tool (EVI-Pro)[50] and was used in the CEC 2018 IEPR Update. **Figure 53** shows how the average day's profile for EV load changes during the 2026-2035 study period and **Table 39** summarizes the forecasted annual EV load energy.
- EV load is assumed to be incremental to any EV load imbedded in baseline load forecast.

Table 38. Cumulative EV population growth

Region	New EV Population (cumulative in thousands)				Source
	2020	2025	2030	2035	
California	1,000	2,500	3,900	5,400	CEC - 2018 IEPR High Demand
Northwest	234	611	1,096	1,500	NWPCC - Mid-Demand Scenario
Southwest, Rocky Mountain, Basin	108	455	880	1,418	Calculated by ES using EIA AEO 2019, CEC
Total	**1,342**	**3,566**	**5,876**	**8,318**	Energy required and shapes based on CEC tools

Figure 53. Average Day's EV Charging Load in 2035



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[50] "California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025": https://www.nrel.gov/docs/fy18osti/70893.pdf

Table 39. EV Load Forecast[51]

EV Demand (MWa)	2026	2030	2035	CAGR (%/yr) 2026-2035
California	1,474	1,897	2,592	5.8%
Northwest	360	511	638	5.9%
Basin	45	70	107	9.1%
Rocky Mountain	55	89	141	10.0%
Southwest	101	164	258	9.8%
Total	**2,034**	**2,731**	**3,736**	**6.3%**

Demand Response Assumptions

- The capital expansion and product cost modeling represented incremental demand response (DR) as identified in IRPs up through 2035.
- GENESYS modeling had NWPCC existing & planned DR through 2024:
  - Winter: 180 MW max response; 7,200 MWh max energy/year; 4-hr response.
  - Summer: 630 MW max response; 25,200 MWh max energy/year; 4-hr response.

9.7 Existing & Planned Resources

Existing Resources

Existing generation, as of January 1, 2019, was based on the following databases: EIA, WECC ADS, and, CAISO Transmission Planning Process. Planned or potential retirement dates of thermal generators were included in the Baseline Case and were sourced from IRPs and the data sources listed above. Capacity expansion modeling logic was allowed to advance, but not delay, assumed retirement dates.

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[51] The Northwest forecasted EV load is consistent with the 7th Plan which assumes 1.5 million vehicles by 2035

Planned Resources

- IRPs, other announcements, and expertise from the study's Technical Advisory Committee were used to determine assumptions for highly uncertain resources (e.g., Site-C, Colstrip).
- Based on IRPs, we assumed that new resources planned before 2026 are constructed. In the case of California, we assumed all resources identified in the California Public Utility Commission (CPUC) Preferred System Plan from the 2017-18 IRP cycle are built in the amounts, technologies, and locations as specified in that plan. The process used to establish the Baseline Case resource portfolio is outlined in **Figure 54.**
- **Figure 55** summarizes the Western U.S. resource mix at the end of 2025, by type, as compared with today (2019).

Figure 54: Process to Define Resources in the Baseline Case

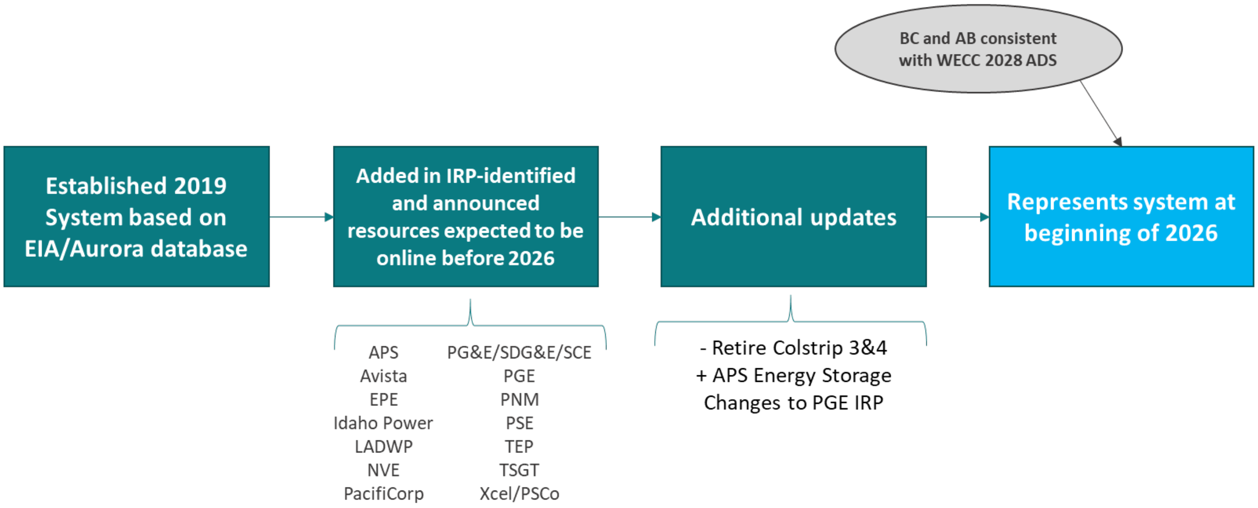
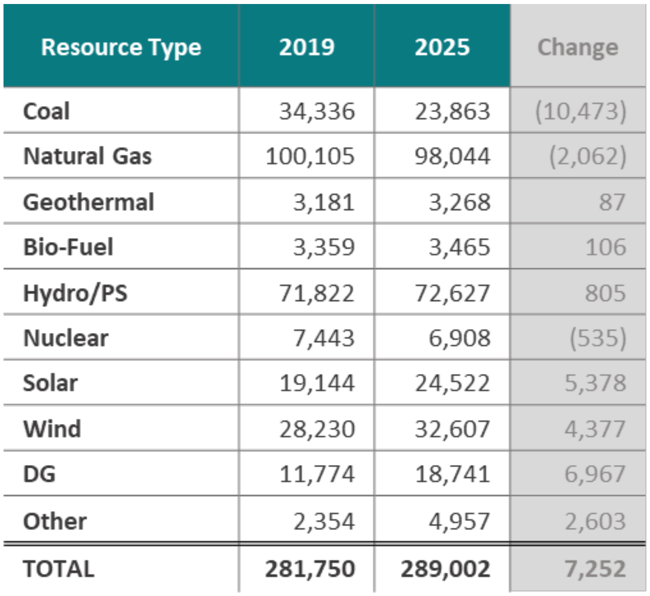


Figure 55: Summary of Existing and Planned Resources in Western U.S. (MW)



Resource Type	2019	2025	Change
Coal	34,336	23,863	(10,473)
Natural Gas	100,105	98,044	(2,062)
Geothermal	3,181	3,268	87
Bio-Fuel	3,359	3,465	106
Hydro/PS	71,822	72,627	805
Nuclear	7,443	6,908	(535)
Solar	19,144	24,522	5,378
Wind	28,230	32,607	4,377
DG	11,774	18,741	6,967
Other	2,354	4,957	2,603
TOTAL	**281,750**	**289,002**	**7,252**

9.8 New Resources Options

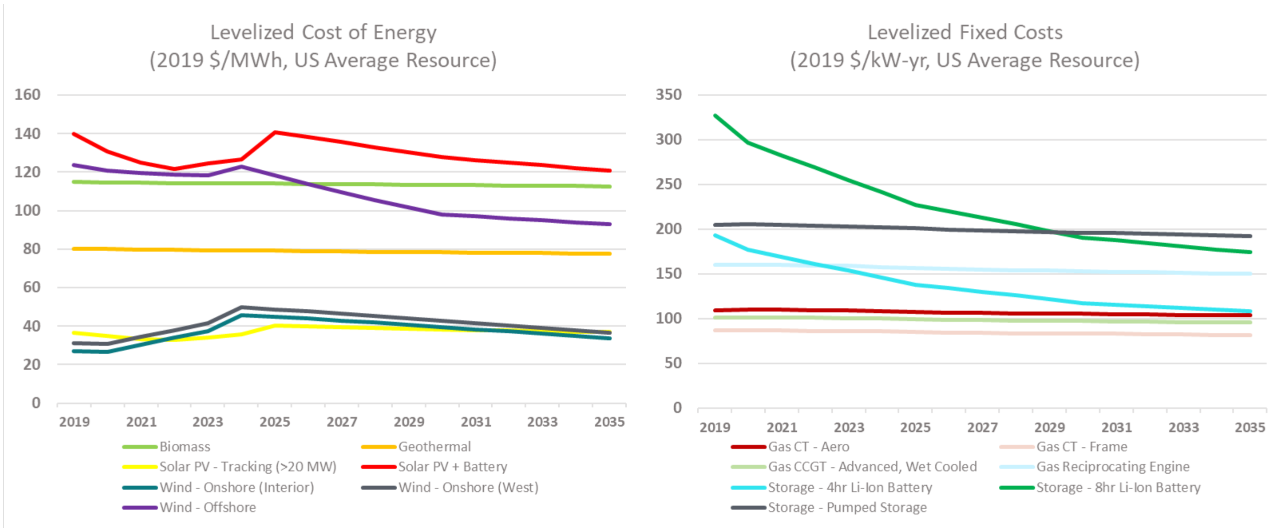
New resource options and their modeling assumptions were developed for every state and region combination. In addition, specific out-of-state new resource options were assumed. New resource types included biomass, natural gas aero-derivative combustion turbine, natural gas frame combustion turbine, natural gas combined cycle, geothermal, solar photovoltaic (PV), 4- and 8-hour lithium-ion storage, 12-hour pumped storage, and wind (onshore and off-shore). The following sub-sections provide more details about the modeling assumptions for these new resource options.

Cost trajectories by resource type benchmarked to today's prices

- Each new resource option had a fixed cost (capital cost, property tax, and insurance) and fixed O&M cost trajectories for the entire study period based on their location and the load each resource might serve. Unless existing transmission capacity was already available or was assumed to be available based on assumed thermal retirements, the fixed cost of out-of-state new resource included the fixed cost of new transmission (e.g., Montana coal). **Figure 56** provides the Levelized Cost of Energy and Levelized Fixed Cost Assumptions for the new resource options.

- Present-day public capital cost and PPA values were used to benchmark 2018 installed cost estimates.
- Assumed that PTC expires and ITC continues at 10%.
- Cost Assumption Data Sources:
  - WECC/E3 Capital Cost Calculator.
  - NREL 2018 Annual Technology Baseline (ATB).
  - PacifiCorp 2019 IRP Resource Table.
  - PacifiCorp 2017R RFP Results and subsequent regulatory filings.
  - Xcel regulatory filings for Colorado Energy Plan.
  - Lazard Levelized Cost of Storage 4.0.
  - "Projecting the Future Levelized Cost of Electricity Storage Technologies"; Schmidt, o. et. Al.; January 2019.
  - Cost and Performance Characteristics of New Generating Technologies; EIA; January 2019.
  - 2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark; Fu, Ran et. al., November 2018.
  - 2017-18 CPUR IRP Input Assumptions (RESOLVE Model Documentation).

Figure 56. Levelized Cost of Energy and Levelized Fixed Cost Assumptions for New Resource Options



Out-of-State New Resource Options & Transmission Availability Assumptions

- The study also considered plausible out-of-state resource options. **Table 40** summarizes the out-of-state new resource options by resource type/location (left column) and the remote destination available for that resource (right column). The study considered transmission cost adders for these options.

Table 40: Out-of-State Resource Options in Capacity Expansion

Resource Location & Type	Out-of-State Load Location
Arizona pumped storage and solar PV	California
Idaho wind and solar PV	California, Oregon, and Washington
Montana wind and pumped storage	Oregon and Washington
Nevada geothermal and solar PV	California
New Mexico wind	Arizona and California
Oregon wind, solar PV, and pumped storage	California and Washington
Washington wind and pumped storage	Oregon
Wyoming wind	California, Colorado, Oregon, and Washington

Technical Potential Capacity Limits

- Technical potential was determined by state and/or resource type as outlined below. **Table 41** summarizes the resulting technical potential assumptions.
    - California:
        - Geothermal based on RESOLVE IRP model potential and adjusted for assumed IRP build of 438; Biomass build adjusted by 270 MW.
        - Wind/solar based RESOLVE IRP potential.
    - Pumped Storage: Technical potential based on active projects in S&P Financial’s market data plus 750 MW per state.
    - Solar & Wind: Lowest of: 25,000 MW or value in NREL RE Potential Study.[52]
    - BESS: No technical limit, assumed 25,000 MW.
    - Biomass: WREZ potential, thinned for states with at least 300 MW potential.
    - Geothermal: WREZ potential, thinned for states with at least 300 MW potential.

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[52] NREL “U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis”: https://www.nrel.gov/docs/fy12osti/51946.pdf

Table 41. Technical Potential Capacity Limits by State

State	Type and Potential (MW)					
	Biomass	Geothermal	Solar	Wind	Pumped Storage	BESS
Alberta	0	0	1,000	25,000	0	25,000
Arizona	300	0	25,000	11,000	4,440	25,000
British Columbia	1,000	300	25,000	25,000	0	25,000
California	1,022	1,362	77,248	7,000	5,902	25,000
New Mexico	0	0	25,000	25,000	750	25,000
Mexico	0	0	25,000	25,000	0	25,000
Nevada	300	1,400	25,000	7,000	2,300	25,000
Montana	0	0	25,000	25,000	1,430	25,000
Washington	0	0	25,000	18,000	3,255	25,000
Idaho	300	300	25,000	18,000	1,150	25,000
Oregon	600	800	25,000	25,000	1,643	25,000
Utah	0	300	25,000	13,000	3,100	25,000
Wyoming	0	0	25,000	25,000	1,850	25,000
Colorado	0	0	25,000	25,000	790	25,000

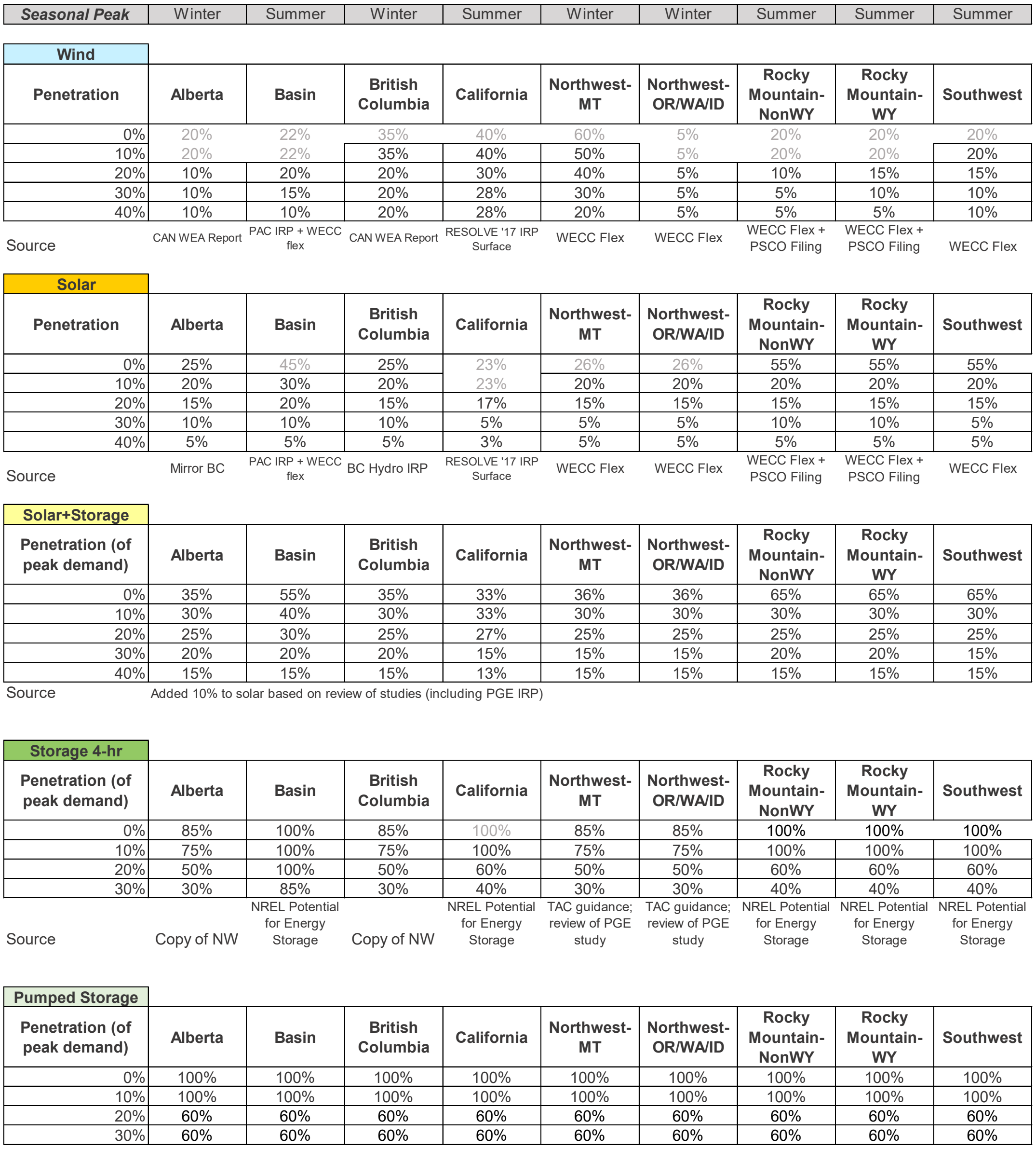
9.9 Resource Capacity Value Assumptions

- Resource capacity values were based on regional or sub-regional location, the location's peak load season, and resource type.
- The capacity value for new wind, solar, and storage resource options was assumed to decrease commensurate with their energy penetration in each portion of the Western system, to represent the decline in capacity value for the marginal. The development of these assumptions took into account where penetrations are project to be in 2026, and what penetrations could get to for each of these resource types by 2035.
- **Table 42** provides the capacity value assumptions for the existing and planned resources, while **Figure 57** provides the capacity value assumptions for new wind, solar, and storage resource options.

Table 42: Assumed Capacity Value of Existing and Planned Resources in Capacity Expansion Modeling

Resource Group	Northwest (MT)	Northwest (OR/WA/ID)	California	Basin	Rocky Mountain (CO)	Rocky Mountain (WY)	Southwest	Alberta	British Columbia
Thermal & Nuclear	100%	100%	100%	100%	100%	100%	100%	100%	100%
Hydro	50%	50%	83%	78%	86%	78%	70%	27%	94%
Solar	26%	26%	23%	45%	55%	55%	75%	26%	26%
Wind	60%	5%	40%	22%	20%	20%	20%	20%	35%
Other (geo, bio)	85%	85%	85%	85%	85%	85%	85%	85%	85%
Storage	85%	85%	100%	100%	100%	100%	100%	85%	85%
DR	100%	100%	100%	100%	100%	100%	100%	100%	100%
Solar + Storage	85%	85%	100%	100%	100%	100%	100%	100%	100%

Figure 57. Assumed Capacity Value of New Wind, Solar, and Storage Resource Options in Capacity Expansion Modeling



Seasonal Peak	Winter	Summer	Winter	Summer	Winter	Winter	Summer	Summer	Summer

Wind

Penetration	Alberta	Basin	British Columbia	California	Northwest-MT	Northwest-OR/WA/ID	Rocky Mountain-NonWY	Rocky Mountain-WY	Southwest
0%	20%	22%	35%	40%	60%	5%	20%	20%	20%
10%	20%	22%	35%	40%	50%	5%	20%	20%	20%
20%	10%	20%	20%	30%	40%	5%	10%	15%	15%
30%	10%	15%	20%	28%	30%	5%	5%	10%	10%
40%	10%	10%	20%	28%	20%	5%	5%	5%	10%
Source	CAN WEA Report	PAC IRP + WECC flex	CAN WEA Report	RESOLVE '17 IRP Surface	WECC Flex	WECC Flex	WECC Flex + PSCO Filing	WECC Flex + PSCO Filing	WECC Flex

Solar

Penetration	Alberta	Basin	British Columbia	California	Northwest-MT	Northwest-OR/WA/ID	Rocky Mountain-NonWY	Rocky Mountain-WY	Southwest
0%	25%	45%	25%	23%	26%	26%	55%	55%	55%
10%	20%	30%	20%	23%	20%	20%	20%	20%	20%
20%	15%	20%	15%	17%	15%	15%	15%	15%	15%
30%	10%	10%	10%	5%	5%	5%	10%	10%	5%
40%	5%	5%	5%	3%	5%	5%	5%	5%	5%
Source	Mirror BC	PAC IRP + WECC flex	BC Hydro IRP	RESOLVE '17 IRP Surface	WECC Flex	WECC Flex	WECC Flex + PSCO Filing	WECC Flex + PSCO Filing	WECC Flex

Solar+Storage

Penetration (of peak demand)	Alberta	Basin	British Columbia	California	Northwest-MT	Northwest-OR/WA/ID	Rocky Mountain-NonWY	Rocky Mountain-WY	Southwest
0%	35%	55%	35%	33%	36%	36%	65%	65%	65%
10%	30%	40%	30%	33%	30%	30%	30%	30%	30%
20%	25%	30%	25%	27%	25%	25%	25%	25%	25%
30%	20%	20%	20%	15%	15%	15%	20%	20%	15%
40%	15%	15%	15%	13%	15%	15%	15%	15%	15%
Source	Added 10% to solar based on review of studies (including PGE IRP)								

Storage 4-hr

Penetration (of peak demand)	Alberta	Basin	British Columbia	California	Northwest-MT	Northwest-OR/WA/ID	Rocky Mountain-NonWY	Rocky Mountain-WY	Southwest
0%	85%	100%	85%	100%	85%	85%	100%	100%	100%
10%	75%	100%	75%	100%	75%	75%	100%	100%	100%
20%	50%	100%	50%	60%	50%	50%	60%	60%	60%
30%	30%	85%	30%	40%	30%	30%	40%	40%	40%
Source	Copy of NW	NREL Potential for Energy Storage	Copy of NW	NREL Potential for Energy Storage	TAC guidance; review of PGE study	TAC guidance; review of PGE study	NREL Potential for Energy Storage	NREL Potential for Energy Storage	NREL Potential for Energy Storage

Pumped Storage

Penetration (of peak demand)	Alberta	Basin	British Columbia	California	Northwest-MT	Northwest-OR/WA/ID	Rocky Mountain-NonWY	Rocky Mountain-WY	Southwest
0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
10%	100%	100%	100%	100%	100%	100%	100%	100%	100%
20%	60%	60%	60%	60%	60%	60%	60%	60%	60%
30%	60%	60%	60%	60%	60%	60%	60%	60%	60%

9.10 Curtailment Cost Assumptions

The study assumed curtailment costs for wind, solar, and hydro resources. Wind and solar generators had negative curtailment costs based on assumptions for production tax credit (PTC) value and the market for delivered renewable energy credits (REC). To simplify the assumptions, the study assumes wind installed after 2020 has no PTC value. **Table 43** summarizes the curtailment cost assumptions. [53]

Table 43. Curtailment Cost assumptions

Fuel Type	Installation Year or Other Description	Curtailment Cost ($/MWh)	Reasoning
Wind	2015 or before	-15	$15/MWh REC value (Assumed PTC period expired)
	After 2015 & through 2020	-40	$15/MWh REC and $25/MWh PTC value
	After 2020	-15	$15/MWh REC value
Solar	All	-15	$15/MWh REC value
Hydro	NWPCC	-300	Already bounded to the NWPCC GENESYS operating limits
	Non-NWPCC	-50	Assumptions from CAISO 2028 Default PCM

9.11 Transmission Topology & Service Charges

The production cost and power flow modeling were nodal and included extensive representations of the Western Interconnection's transmission system. The production cost

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[53] Hydro had very high negative curtailment costs so as not to disrupt its constrained operation. Hydro bounded by NWPCC operating limits had the lowest curtailment prices since their output already represented levels within their reliable 2-, 4-, and 10-hour sustaining peaking capabilities and, therefore, they'd be the least likely to curtail their output.

and capital expansion models assumed zero transmission service wheeling charges to represent that a regional, WECC-wide market had been achieved by 2026. The capital expansion and GENESYS modeling used zonal topologies shown in **Figure 58** and **Figure 59**, respectively.

Figure 58. Topology of capital expansion modeling

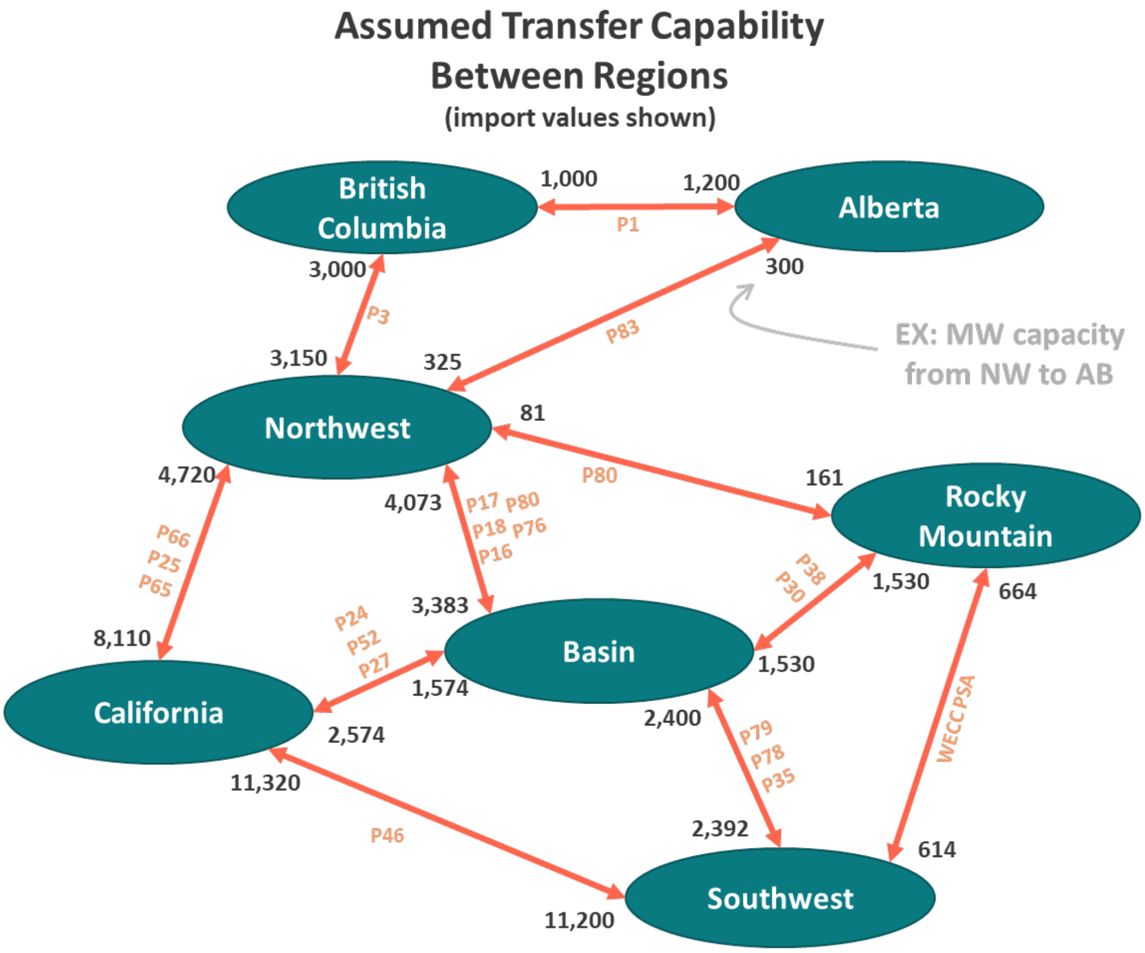
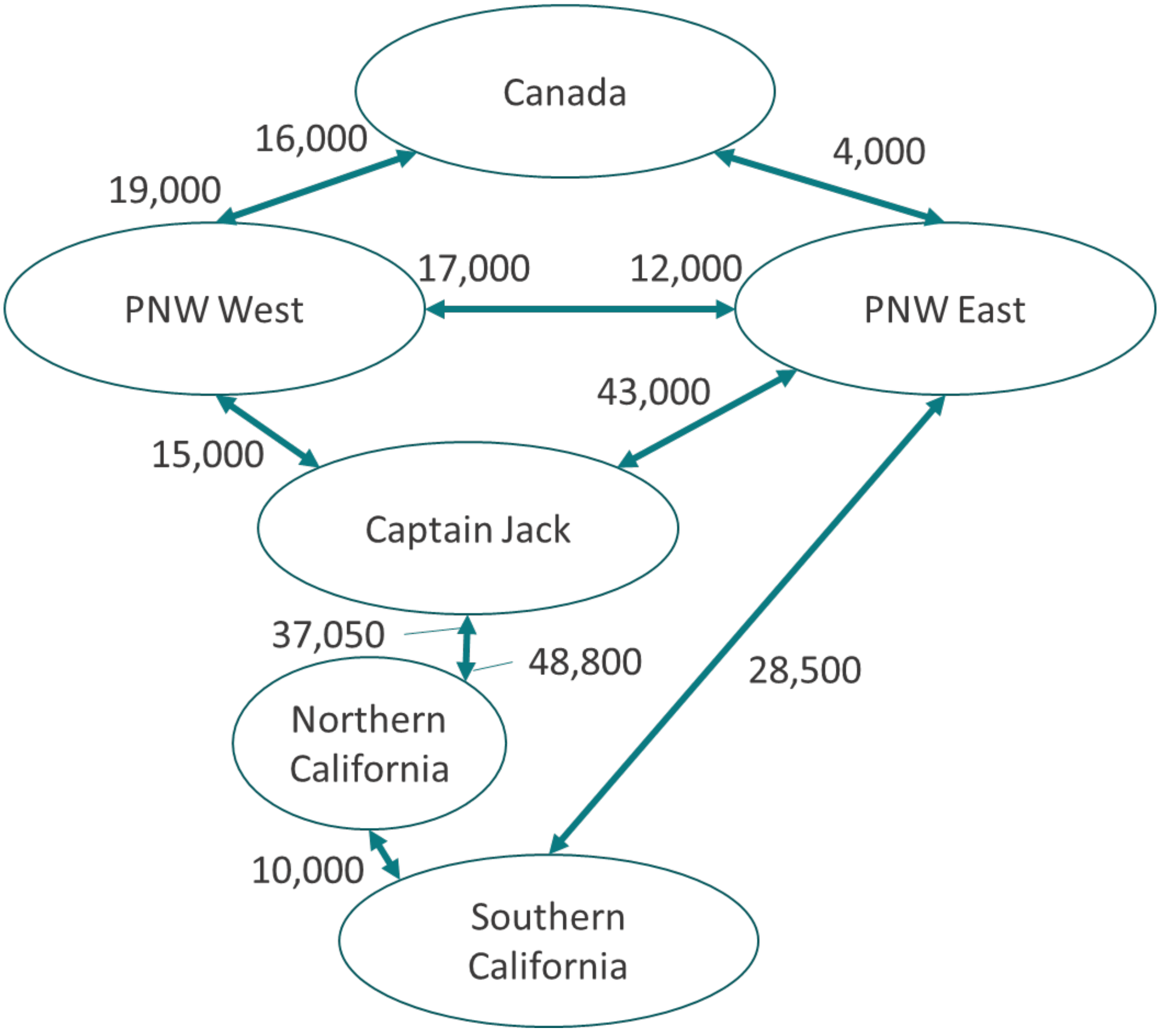


Figure 59. Topology of GENESYS modeling



9.12 Operating Reserve & Ancillary Services Modeling

Capital Expansion Modeling

- Operating reserve requirements were assumed to be 6.5% of the hourly load in each region. This approximated the FERC 789 requirement for contingency reserves (the greater of 3% of generation plus 3% of load or the largest single generator's output), plus a small amount (0.5%) extra that would not overlap with the estimated 1.5-2.5% of load requirement for regulation and load following ancillary services (i.e., the resources contributing toward the contingency resources were assumed to simultaneously contribute all but 0.5% of the regulation and load following requirement).

Production Cost Modeling

- Ancillary services and contingency reserves were modeled with varying levels of granularity, including BAA, reserve sharing group, and the region.
    - Contingency reserve requirements from FERC Order 789 and WECC BAL-002-WECC-2 reliability standards were represented, half of which were assumed to be spinning reserves and were explicitly modeled.[54] BAA's in the U.S. were assumed to share the spinning requirement with others in their reserve sharing groups while locally carrying 25% of their own spinning reserve requirement.
    - Regulation and load following ancillary service requirements were assumed for each region. The regulation up & down requirements were each 1.5% of load while the load following up & down requirements were 2.5% & 1.5% of load (respectively).
    - The frequency response obligation for the Western Interconnection was assumed to be 2,505 MW based on the net of the Resource Contingency Protection Criteria and Credit for Load Resources in the NERC 2018 Frequency Response Annual Analysis (FRAA).[55]
- **Table 44** summarizes the generation types available to provide ancillary services.

Table 44. Resources Assumed Eligible to Contribute Ancillary Services

Ancillary Service	What can contribute
Spinning Reserve, Regulation Up, & Load Following Up	• Natural gas and other gas-fired thermal generators • Storage and hydro resources
Regulation Down & Load Following Down	• Natural gas and other gas-fired thermal generators • Storage and hydro resources • Wind and solar resources
Frequency Response	• Natural gas-fired thermal generators • Storage and hydro resources

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[54] The non-spinning reserve requirement was not modeled explicitly due to the lack of quick-start resource data.

[55] https://www.nerc.com/comm/OC/Documents/2018_FRAA_Report_Final.pdf

9.13 Planning reserve modeling

Table 45 summarizes the assumed planning reserve margin (PRM), firm import, and firm export constraints for each region based on recent NERC Long-Term Reliability Assessments, NWPCC Resource Adequacy Assessments, and remote resource power purchase agreements (PPAs).

Table 45. Planning Reserve Margin Assumptions

Region	Planning Reserve Requirement (%)	Firm Imports (MW)	Firm Exports (MW)	Sources & Considerations
Alberta	**11%**	0	0	NERC 2018 LTRA
Basin	**13%**	Through 2030: 159 After 2030: 81	0	PacifiCorp share of Craig 2 (81 MW) and Hayden 1 +2 (78 MW) through 2030
BC	**11%**	0	0	NERC 2018 LTRA
California	**15%**	9,891 MW	0	CA CPUC 2017-18 IRP. Import based on CAISO 2017 allocation of import capability for RA (11,310 MW), reduced to account for Palo Verde and Hoover Shares.
Northwest	**13%**	3,000 MW	Winter: 1,000 MW Summer: 2,000 MW	Import based on import from CA in NWPCC 2023 Adequacy Assessment. Export based on PNUCC 2018 Northwest Regional Forecast
Rocky Mountain	**17%**	0	Through 2030: 159 After: 81	Craig 2 and Hayden 1 +2 - PacifiCorp share
Southwest	**15%**	0	1500 MW	Hoover and PV Shares

9.14 Fuel prices

The Northwest Power and Conservation Council Henry Hub natural gas price forecast was preferred over other forecasts because of its intra-year volatility, shown in **Figure 60**. **Table 46** provides the average annual Henry Hub natural gas price assumptions for more reference. Forecasted Baseline case coal prices using data from the 2018 EIA Annual Energy Outlook (AEO).

Figure 60. Henry Hub Natural Gas Price Forecast (2019$/mmBtu), provided by NWPCC

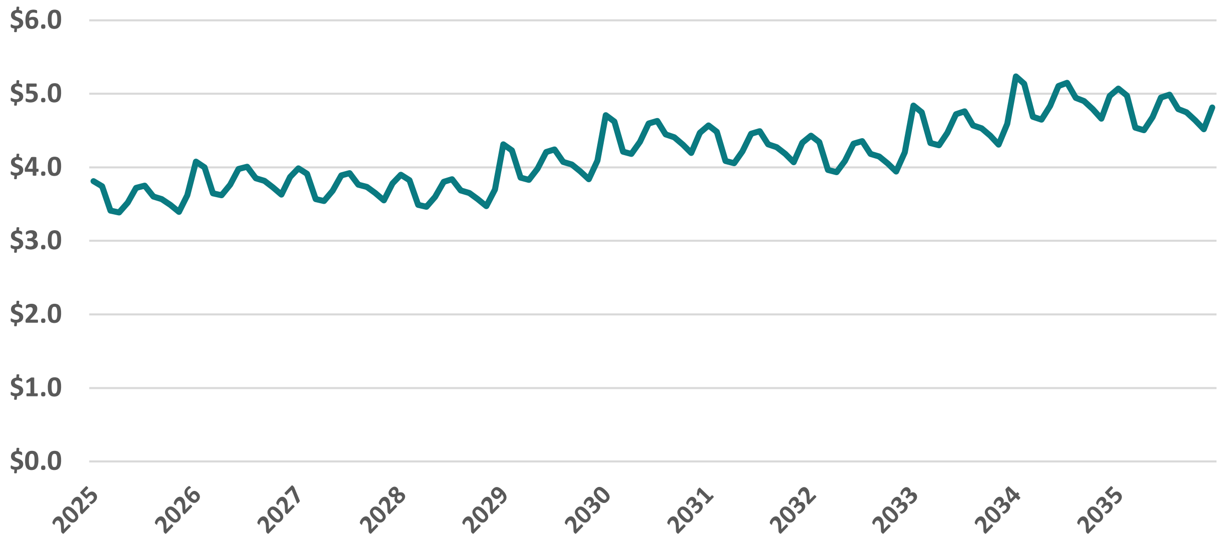

Table 46. Annual Averages of Henry Hub Natural Gas Price Forecast (2019$/mmBtu)

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
3.832	3.749	3.667	4.055	4.429	4.295	4.164	4.551	4.923	4.769

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