Electrification in the Western Interconnection:

Planning for Load Growth, Flexibility, and Reliability

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1. Summary

A. Purpose

This paper was developed by WIEB staff as part of the Western Interstate Energy Board's Reserve Expenditure Plan to support a shared, region-wide understanding of how transportation and building electrification are affecting electric system planning in the Western Interconnection. As states and provinces advance emissions reduction goals, zero-emission vehicle policies, building performance standards, and related electrification initiatives, utilities are increasingly projecting sustained load growth and meaningful changes in load shape, including winter peak risk in colder regions and steeper evening ramps in high-solar systems. Although not the focus of this paper, utilities are simultaneously grappling with large load growth, primarily due to datacenters, and these large loads complicate load growth projections.

This paper includes a comparative overview of state and provincial electrification and emissions reductions policies across the Western Interconnection. The policy review provides critical context for understanding why electrification assumptions vary across utility plans and how differences in statutory targets, incentives, and building and transportation requirements translate into divergent load growth trajectories and planning needs.

Finally, this paper synthesizes findings from a review of recent Integrated Resource Plans (IRPs) across the Western Interconnection and draws on leading research to identify common modeling approaches, key divergences in assumptions, and implications for resource adequacy and system flexibility. The intent is not to prescribe a single policy pathway, but to highlight opportunities for improved transparency, data alignment, and planning consistency, so regulators, policymakers, and utilities can better anticipate electrification-driven reliability risks and investment needs while maintaining affordability and supporting state and provincial policy objectives. By placing utility forecasts alongside the policy environments in which they operate, the paper highlights where policy ambition may be outpacing planning assumptions, as well as where planning frameworks are adapting to emerging policy signals.

B. Key Findings

- **Electrification is a large driver of sustained load growth in areas of the West**, led primarily by transportation and building heating. Policymakers should expect continued upward pressure on electricity demand as these sectors scale.
- **Electrification is changing** not only how much electricity is needed, but when and where systems are most stressed. Seasonal peaks are shifting, evening ramps are steepening, and winter reliability risks are becoming more significant across the region.
- **Utilities are adopting more advanced probabilistic and hourly planning tools** to respond to these changes, but approaches and assumptions still vary widely across the interconnection. This creates inconsistency in understanding where reliability risks exist, how regional resource adequacy is evolving, and what long-term investments may be needed.
- In many jurisdictions, **policy goals and customer adoption are advancing faster than planning assumptions**. Without better alignment, shared data inputs, and common modeling frameworks, this gap may increase planning uncertainty, procurement challenges, and investment risk.

2. Introduction

A. <u>What Is Electrification?</u>

Electrification refers to the transition from fossil fuel use in transportation, buildings, and industrial processes to end-use energy supplied by electricity. For purposes of this paper, electrification encompass two major sectors:

Transportation Electrification:	Building Electrification:
Adoption of electric vehicles (EVs), expansion of public and private charging infrastructure, and the electrification of medium- and heavy-duty fleets.	Conversion of heating, cooling, and cooking from fossil fuels to electric systems, including high-efficiency heat pumps and water heaters.

As technologies such as EVs and heat pumps mature and become more readily available, the speed, scale, and concentration of adoption create new challenges in planning for the electric grid. Electrification alters not just the total magnitude of demand, but its shape, timing, and geographic distribution. In some areas, this may shift many Western utility systems from summer to winter peaks and intensify intra-day ramping.

B. <u>Distinguishing Electrification from Large-Load Growth</u>

This paper focuses on electrification, while acknowledging large-load growth as a parallel challenge. Both trends increase electricity demand across the Western Interconnection, but they are distinct drivers requiring different planning approaches.

Electrification is largely policy- and technology-driven, reflecting a broad transition of millions of end-uses such as vehicles, space and water heating, and industrial equipment from fossil fuels to electricity. Its impacts emerge gradually, are relatively forecastable through long-term planning, and primarily reshape load shapes and seasonal peaks.

> **Of Note**
>
> **Electrification** and **large-load growth** are both distinct drivers requiring different planning approaches.

Large-load growth, by contrast, is market-driven and concentrated, often stemming from data centers, hydrogen production, and other energy-intensive facilities that can connect to the grid at transmission scale with little lead time. These loads can create sudden, localized step changes in demand that challenge existing interconnection and capacity planning processes.[1]

C. <u>Western System Context</u>

The Western Interconnection spans 14 U.S. states, two Canadian provinces, and northern Baja California in Mexico, serving over 90 million people through a complex, multi-jurisdictional network

[1] The Western Interstate Energy Board launched a new webinar series through our Reserve Expenditure Plan to explore the challenges and opportunities presented by new large industrial electricity loads across the Western Interconnection. More information can be found on the WIEB website HERE.

of utilities, balancing authorities, and markets. The system consists of more than 150,000 miles of transmission lines and has a peak load of over 160 GW. The region's diverse policy landscape, climate variability, and interconnected infrastructure make it both a proving ground and a stress test for managing electrification at scale.

Against this backdrop, Integrated Resource Plans (IRPs) across the region now show 1–2% annual load growth linked to electrification. Some utilities project substantial winter peak increases by 2045, and California and Southwest utilities are already seeing both emerging winter peak pressures and increasingly steep evening ramps driven in part by EV charging. Electrification also compounds the uncertainty of resource adequacy. Many utilities are transitioning toward stochastic and hourly modeling frameworks, but approaches and assumptions differ widely. Some incorporate managed charging or building flexibility; others treat electrification as static, inflexible load. This inconsistency risks underestimating capacity needs and peak timing, particularly in cold-climate balancing areas.

D. <u>Key Reports and Context</u>

A growing body of national and regional reports provides guidance for integrating electrification into long-term planning, particularly as electrification changes not only overall demand but also load shapes, seasonal peaks, and where grid impacts emerge. Four recent studies are especially useful as a technical foundation for understanding how electrification is being incorporated into policy and utility planning, and what methodological updates are needed for credible forecasting in the West.

Lawrence Berkely National Laboratory's *Guidance on Incorporating Building and Transportation Electrification into Long-Term Load Forecasts* (2024)[2] provides a framework for utilities, especially municipal and distribution-level entities, to integrate building and transportation electrification into long-term forecasting. The report lays out a seven-step process that moves from defining use cases and scope through base-year calibration, scenario design, technology selection, incremental load-estimation, and application to planning.

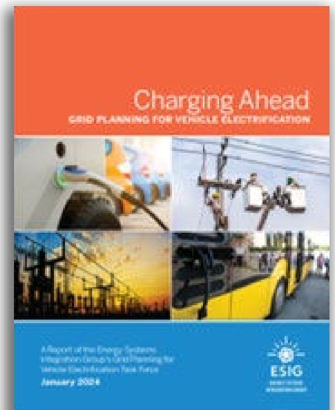

ENERGY MARKETS & POLICY

Guidance on incorporating building and transportation electrification into long-term load forecasts

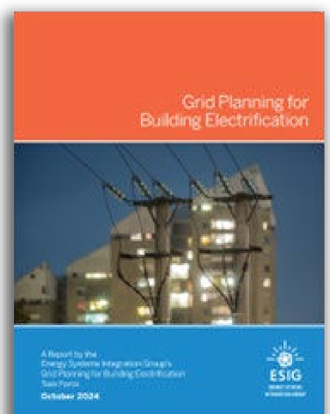
Sean Murphy, Margaret Pigman, and Natalie Mims Frick
December 2024

[2] Lawrence Berkeley National Laboratory (LBNL). New Framework for Incorporating Electrification into Long-Term Electricity Load Forecasts. December 2024. Available at: https://eta-publications.lbl.gov/sites/default/files/2024-12/muni_load_forecasting_guidance_doc_final.pdf

A core message is that traditional econometric approaches can understate electrification because they do not capture new end uses or nonlinear adoption trends. At the same time, the report demonstrates through case studies that relying on uncalibrated national models can overstate winter peaks without local validation. Across these steps, LBNL emphasizes transparent documentation and standardized assumptions so that methods and results are comparable across utilities and regions. For Western systems, this guidance is particularly relevant because consistent electrification assumptions across IRPs and resource-adequacy studies support more coherent scenario development, better representation of seasonal peaks, and stronger alignment with policy.



Planning challenges associated with transportation electrification are the focus of ESIG's *Charging Ahead—Grid Planning for Vehicle Electrification* (2024)[3]. This report emphasizes that EV adoption and charger deployment are moving quickly—often faster than grid upgrades—since public chargers and fleet depots can be built in months rather than years. ESIG argues that utilities should use locational adoption modelling that differentiates by vehicle class, charger type, and usage pattern. The reports also highlights strategies to reduce peak impacts and avoid unnecessary capacity expansion, including managed charging, time-of-use rates, and fleet load control, while stressing that successful implementation requires coordination among utilities, regulators, and charging-network developers. For Western states, where EV adoption is already high in several areas and fleet electrification is emerging elsewhere, ESIG's recommendations underscore that proactive distribution planning and coordinated siting can help shift EV load from being primarily a stressor to becoming a flexible reliability resource.



ESIG's *Grid Planning for Building Electrification* (2024)[4] similarly argues that building electrification should be treated as a major planning driver because it can reshape system load patterns and resource needs. The report emphasizes that electrification of heating, water heating, and appliances can shift peaks into colder months, raising potential winter resource adequacy risks. It notes that widespread building electrification could require 10-70% more generation capacity depending on adoption and efficiency. ESIG also warns that many planning models remain summer-centric, which can lead to underestimation of future winter constraints. As a response, the reports emphasize demand flexibility and efficiency—such as smart thermostats and improved building envelope efficiency to increase the duration of thermal storage from a building—as first line mitigations, while also recommending proactive and data-driven grid upgrades.

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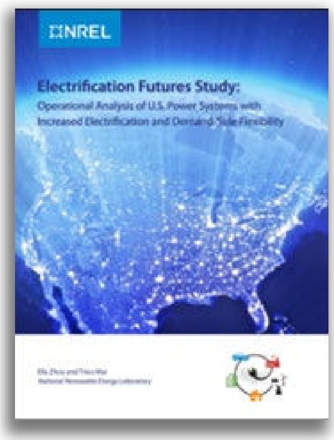
[3] Energy Systems Integration Group (ESIG). Charging Ahead: Grid Planning for Vehicle Electrification. January 2024. Available at: https://www.esig.energy/wp-content/uploads/2024/01/ESIG-Grid-Planning-Vehicle-Electrification-report-2024.pdf

[4] Energy Systems Integration Group (ESIG). Grid Planning for Building Electrification. October 2024. Available at: https://www.esig.energy/wp-content/uploads/2024/10/ESIG-Grid-Planning-Building-Electrification-report-2024.pdf

For the West, ESIG's findings highlight that climate diversity will produce uneven system impacts: some areas may become winter-peaking due to building heating switching from gas to electric heat pump while others face increased evening ramp pressures especially in the summer. Overall, the report reinforces that building electrification is not simply incremental growth, but a load-shape transformation that must be represented directly in planning.



At a broader system level, NREL's *Electrification Futures Study (EFS)*[5] provides a national assessment of how widespread electrification could affect demand, the generation mix, and reliability through 2050. This study finds that, under high-electrification scenarios in the U.S., electricity use could rise 25-40% by 2050, with transportation driving the newest load. EFS also emphasizes that electrification changes load shapes, including the emergence of winter peaks and evening ramps across multiple climates. It highlights that flexible demand (such as EV, charging storage, and thermal loads) can offset up to half of the new capacity needs if it is integrated into planning, and it points to the value of advanced hourly modeling that links end-use dynamics with grid outcomes. For Western planning, EFS serves as a benchmark for scenario analysis and reinforces the need to model not only total load, but also its temporal and spatial distribution, especially as winter resource adequacy and transmission congestion becomes a region wide concern.

Finally, Rocky Mountain Institute's (RMI) *The State of Utility Planning*[6] reviews more than 50 U.S. utility IRPs and finds that many still understate electrification and lack scenario diversity. RMI reports that numerous plans assume static load shapes or outdated policy environments, undermining credibility as electrification accelerates. In particular, fewer than one-third of IRPs model high-electrification scenarios or flexible load management, and many utilities continue to rely on legacy econometric methods that underpredict load growth by ignoring EV and building electrification trends. RMI therefore calls for scenario-based planning, clearer documentation of assumptions, and greater stakeholder transparency so that forecasts reflect evolving policy and technology trajectories. For the West, this largely serves as a reality check: despite ambitious policies, many IRPs lag actual electrification and policy momentum, suggesting a need for regulators and regional entities to encourage scenario-based planning and data consistency.

Across these reports, a consistent picture emerges: electrification is accelerating faster than many existing planning frameworks account for, and it will transform not only the magnitude of demand but also its shape, timing, and geographic concentration. The literature collectively supports more transparent assumptions, more scenario-driven planning, and more explicit treatment of electrification-driven load shape changes in Western utility and regional planning processes.

E. <u>Limitations and Scope</u>

This paper is intended to synthesize planning trends and emerging themes related to electrification across the Western Interconnection, rather than to produce a definitive forecast of future load

[5] National Renewable Energy Laboratory (NREL). Electrification Futures Study (EFS). May 2021. Available at: https://docs.nrel.gov/docs/fy21osti/79094.pdf

[6] Rocky Mountain Institute (RMI). The State of Utility Planning, 2025 Q3. October 15, 2025. Available at: https://rmi.org/the-state-of-utility-planning-2025-q3/

growth or reliability outcomes. The analysis draws on publicly available Integrated Resource Plans and policy materials that vary in scope, modeling approaches, and update cycles, and reflects a snapshot in time based on plans published between 2021 and 2025 and policies in effect or formally adopted at the time of review. Rapidly evolving state and provincial electrification policies, differences in how utilities incorporate those policies into planning assumptions, and the absence of independent validation of utility forecasts introduce additional uncertainty. The regional focus of this paper also limits its ability to capture distribution-level constraints and local infrastructure readiness, and large-load growth is treated as a parallel but separate issue. A more detailed discussion of these limitations is provided in Section 6. Limitations.

3. State Policies and Goals

A. Policy Overview

Electrification and emissions reduction policies across the Western Interconnection vary widely in ambition, design, and implementation[7]. States and provinces with aggressive mandates—such as California, Colorado, Washington, Oregon, and British Columbia—have adopted binding 100% emission-free energy standards, zero-emission vehicle (ZEV)[8] requirements, and building performance standards that explicitly accelerate electrification. Emerging policy states and provinces such as Alberta, Nevada, New Mexico, and Utah are aligning clean-heat programs and EV infrastructure investments with broader decarbonization goals. Other states, including Arizona, Idaho, Montana, and Wyoming, prioritize fuel diversity, cost containment, and continued investment in fossil resources and carbon capture. This asymmetry translates into divergent trajectories for load growth, peak timing (for example, winter peaks versus evening ramps), and resource adequacy needs across the region.

At a high level:

- **Aggressive States and Provinces:** *California, Colorado, Washington, Oregon, and British Columbia* have codified 100% carbon-neutral targets and are advancing zero-emission vehicle (ZEV) and building performance standards that will substantially increase electricity demand over the next two decades.
- **Emerging Policy States and Provinces:** *Alberta, Nevada, New Mexico, and Utah* have adopted renewable energy goals and greenhouse gas (GHG) reduction plans and are now developing coordinated EV and building electrification programs.
- **Incremental or Resource-Diversity States:** *Arizona, Idaho, Montana, and Wyoming* continue to prioritize affordability, reliability, and fuel flexibility, relying on incentives and voluntary measures rather than mandates.

Table 1 below summarizes electrification and emissions reduction policies in the West. This policy diversity makes interregional coordination critical to maintaining reliability and resource adequacy as electrification accelerates unevenly across the West.

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[7] Terminology for these goals varies by jurisdiction with some referring to these as "clean energy", "renewable", "net-zero", etc. For the purposes of this report WIEB uses "emissions reduction policies" to describe these policies collectively.
[8] Zero-emission vehicles (ZEVs), primarily battery-electric (BEVs) and hydrogen fuel-cell (FCEVs), produce no direct tailpipe pollutants. While they eliminate exhaust during operation, their total environmental impact includes upstream emissions generated during the production and distribution of the electricity or hydrogen fuel.

Table 1: Summary of Electrification and Emissions Reduction Policies in the West[9]

State/ Province	Emissions Reduction Policy Target	Vehicle Electrification	Building Policy
AB	30% renewable by 2030	100% ZEV by 2035 (national standard)	NECB 2020 for new construction and NECB 2023 Alberta Edition
AZ	No target	Tax credits and rebates; no defined goal	No state code; currently uses 2018 IECC as its base
BC	100% net-zero by 2050	100% ZEV by 2035 (national standard)	Zero-carbon buildings by 2030
CA	100% zero-carbon energy by 2045	100% of new car sales to be zero-emission by 2035	Title 24, Part 6 – supports zero-net energy goals
CO	100% net-zero GHG emissions by 2050	Clean Cars Standard – 82% of new light-duty vehicle sales electric by 2032	2024 IECC + Model Low Energy and Carbon Code (HB22-132)
ID	No state target; Idaho Power goal of 100% carbon-free by 2045	No tax rebates or credits; Idaho Power EV programs	2018 IECC with amendments for residential and commercial projects
MT	emissions reduction target repealed	No ZEV targets	2021 IECC with amendments
NV	50% renewable energy by 2030	ZEV targets for state fleet	Targets for state buildings
NM	80% renewable by 2040	ZEV targets for state, heavy-duty, and light-duty vehicles	2021 IECC with amendments; Sustainable Building Tax Credit
OR	100% net-zero energy by 2040	90% ZEV sales by 2035	State requirements + incentives
UT	Beehive GHG Reduction Plan	Tax credits for EV infrastructure	Electric-ready home initiatives
WA	100% clean energy by 2045	100% EV sales by 2035	Zero-GHG homes by 2031; Clean Building Performance Standard (HB 1257)
WY	Carbon capture for coal plants	No ZEV goals or policies	Voluntary building codes

[9] Acronym Notes: Greenhouse Gas (GHG); Zero-emission Vehicle (ZEV); National Energy Code of Canada for Buildings (NECB); International Energy Conservation Code (IECC)

B. <u>Policy Landscape by Sector</u>

1. Emission Reduction and GHG Targets

a. **100% Net-Zero Carbon Commitments for Electricity Generation**
California, Washington, Oregon, and British Columbia require 100% zero-carbon electricity by 2040–2045. New Mexico targets 80% renewables by 2040, while Colorado aims for 100% carbon-free electricity by 2050. Other states (e.g., Idaho, Wyoming) have no binding emissions reduction targets but utilities may participate in voluntary programs that are not state administered.

b. **GHG Reduction Goals**
Several states have statutory economy-wide GHG targets, such as 45% below 2005 levels by 2030 (New Mexico) and net-zero by 2050 (Washington and Oregon). Others emphasize technology pathways rather than emissions targets, for example, Wyoming's focus on carbon capture efforts and Utah's Beehive Plan which hopes to reduce CO_2 intensity by 2050.

2. Transportation Electrification

a. **ZEV and EV Sales Mandates**
California's Advanced Clean Cars II standard (100% ZEV sales by 2035) has been adopted or aligned with by Washington, Oregon, Colorado, Nevada, and New Mexico. Medium- and heavy-duty ZEV rules are also expanding across these jurisdictions. Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming participate in the REV West initiative[10], supporting coordinated highway corridor charging. British Columbia requires 100% ZEV light-duty sales by 2035 and has implemented stringent charging infrastructure requirements for new developments.

b. **Incentives and Infrastructure**
Many states offer rebates or tax credits for EV purchases and utility-administered charger incentives. Idaho and Nevada have developed EV infrastructure baseline plans and public fast-charging corridors. Arizona utilities and municipalities offer time-of-use (TOU) rates to encourage off-peak charging, an early example of flexible load management at scale.

3. Building Electrification and Efficiency

a. **Building Codes and Standards**
Washington has Zero-GHG emission building requirements by 2031. Oregon is implementing performance-based building code with progressive efficiency improvements toward 2030 goals. Colorado has adopted 2024 IECC with clean-heat performance standards for gas utilities. Idaho and Montana maintain IECC-based codes with local amendments and limited enforcement. California continues to strengthen Title 24 codes and local "reach codes" that effectively ban new gas hookups in many municipalities.

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[10] Regional Electric Vehicle (REV) West is a partnership of Governors from eight western states—Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming—who signed a Memorandum of Understanding (MOU) to provide a framework for creating an Intermountain West EV Corridor that will make it possible to drive an EV across major transportation corridors in the west.

b. **Clean Heat and Electrification Targets**
Colorado and New Mexico have Clean Heat Standards requiring gas utilities to reduce GHG emissions through electrification, efficiency, and renewable gas. British Columbia's CleanBC Plan mandates zero-emission new buildings by 2030. Utah and Arizona rely primarily on market incentives and voluntary programs to encourage adoption.

4. Demand Management and Load Flexibility

a. **Time-of-Use (TOU) and Demand Response**
TOU rates are increasingly widespread, with active programs in Arizona, Colorado, Idaho, Utah, Washington, and Oregon. Utilities offer targeted demand-response incentives for customers who can reduce load during system peaks. California's Demand Side Grid Support Program and Load Shift Pilot integrate distributed flexibility resources into system operations.

C. Implications for Electrification Planning

Across the Western Interconnection, differences in state and provincial electrification policies are creating a wide range of load growth trajectories. This uneven policy landscape complicates regional load forecasting and makes it more difficult to anticipate how electrification will affect power flows and shared resource adequacy needs.

At the same time, in many jurisdictions, electrification policy goals are advancing faster than the assumptions reflected in current Integrated Resource Plans. In particular, targets for electric vehicle adoption and building electrification often exceed what utilities are modeling in the near term, increasing the risk that capacity and transmission needs may be underestimated as electrification accelerates.

Despite these challenges, there are clear opportunities for greater harmonization. By using common modeling frameworks, improving data sharing, and aligning rate design and demand-side strategies, states and utilities can better coordinate how electrification is reflected in planning and ensure more consistent and reliable outcomes across the Western Interconnection. The next section dives deeper into utility IRPs in the West and how they account for electrification in the modeling and planning assumptions.

4. Integrated Resource Planning and Electrification Modeling Across the Western Interconnection

Integrated Resource Plans (IRPs) across the Western Interconnection increasingly recognize electrification as a core driver of long-term load growth and system transformation. Nearly every major Western utility incorporates transportation and building electrification into demand forecasts, reflecting the combined influence of federal incentives (e.g., the Inflation Reduction Act), state and provincial policy goals, and customer adoption trends.

This paper reviewed 28 IRPs from states across the Western Interconnection to assess the extent to which utilities are incorporating electrification into their planning processes. The reviewed IRPs were published between the years of 2021 and 2025 and include forecast horizons spanning 10 to 23 years. This section summarizes the forecasting frameworks utilities are using and how electrification is considered within them.

A. <u>Electrification Modeling Across Utilities</u>

Utilities across the Western Interconnection employ a range of modeling approaches to integrate electrification into their IRPs, reflecting differences in policy environments, data availability, and regulatory guidance. While the tools and assumptions vary, several methodological trends are shaping how planners quantify electrification and its impacts on long-term system needs.

Hybrid econometric and end-use frameworks have become standard for comprehensive load forecasting in systems with mature data and established load research. These bottom-up, load-shape driven models blend econometric drivers with detailed end-use representations, simulating class-level hourly behavior to represent EV charging, building heating, and industrial load shifts across multiple policy or adoption scenarios. This approach allows planners to analyze how specific technologies and behavioral patterns influence load shapes, peak timing, and seasonal reliability. This method also supports hourly integration with capacity expansion tools, improving the alignment between demand forecasting and resource planning.

Top-down, policy aligned methods remain prevalent where planning is centrally coordinated. In this approach, utilities adopt statewide or jurisdictional demand forecasts, such as those developed through regulatory processes, ensuring consistency with statutory decarbonization goals and statewide electrification targets. Electrification is integrated primarily through policy-defined scenarios rather than utility-specific econometric modeling, reinforcing alignment and transparency across the planning framework.

Hybrid econometric and scenario-based approaches are increasingly used where rapid electrification and economic transformation are key uncertainties. These top-down, scenario-driven models layer econometric forecasts with sectoral and macroeconomic growth scenarios, incorporating drivers such as data center expansion, EV fleet deployment, industrial electrification, and population migration. They emphasize how different policies or economic futures change the magnitude and timing of electrified load, often testing system sensitivity to temperature extremes, market shifts, and flexibility constraints.

Simplified or implicit econometric approaches remain in use among smaller, multistate utilities. These forecasts rely on Statistically Adjusted End-Use (SAE) models or traditional regression based econometric frameworks to project total energy and peak demand, capturing electrification effects indirectly through macroeconomic, weather, and appliance efficiency variables. Inputs are typically derived from historical load data, demographic forecasts, and elasticity assumptions, producing a consistent but aggregated view of load growth across customer classes. This approach remains suitable for systems with smaller service territories or limited electrification mandates, where historical trend extrapolation continues to provide a reasonable planning basis.

These approaches are not mutually exclusive. IRPs often combine elements from multiple categories with one primary forecasting method. Across these approaches, annual energy growth forecasts range from roughly 0.8 percent in mature, efficiency-saturated systems to about 3.5 – 3.7 percent in high-growth territories. This dispersion reflects varying customer bases and underscores how modeling scope and policy ambition translate directly into projected load growth and resource need. For the Western Interconnection overall, total annual demand is forecast to grow 20.4%, from 942 TWh in 2025, to 1,134 TWh in 2034. That increase is more than double the 9.6% growth forecast in resource plans filed in 2022, and over four times the historical growth rate of 4.5% between 2013 and 2022, due primarily to new large load projections and electrification.[11]

> **Of Note**
>
> For the Western Interconnection overall, **total annual demand** is forecast **to grow 20.4%**, from 942 TWh in 2025, to 1,134 TWh in 2034.

B. <u>Transportation and Building Electrification</u>

Transportation and building electrification are principal sources of incremental load growth across the Western Interconnection through 2045. Modern IRPs treat these loads not as isolated sensitivities, but as structural demand drivers requiring explicit modeling of adoption, hourly profiles, and system interactions. Planners are refining both the magnitude of these loads and the shape of their impact on net demand, incorporating evolving policy mandates, incentives, and customer behavior.

Electric Vehicles

Nearly every major IRP now includes explicit EV adoption forecasts derived from a combination of state EV mandates, federal tax incentives, and observed market trends. Forecasting typically occurs at the vehicle-type level (light-duty, medium/heavy-duty, and fleet or transit), each with distinct charging behaviors. Adoption trajectories are typically benchmarked to state policy targets (e.g., California's 100% ZEV sales by 2035, Washington's Clean Cars 2030, or Colorado's EV plan) or market adoption trends and incorporated into low, base, and high EV adoption scenarios to quantify uncertainty and test resource adequacy under accelerated electrification conditions. Load impacts are often expressed both in annual energy terms and in hourly peak contribution, often showing new late-evening peaks that challenge existing resource portfolios. Planners increasingly incorporate managed charging and time-of-use assumptions to evaluate the extent to which flexible charging can flatten evening ramps. In some IRPs, EV load is explicitly integrated into production cost or capacity expansion models as a controllable or partially deferrable resource to assess operational flexibility, rather than as a static demand increase.

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[11] WECC. Western Assessment of Resource Adequacy, 2024. January 2025. Available at: https://feature.wecc.org/wara/

Building Electrification

Planners are increasingly incorporating space- and water-heating electrification using heat pump adoption models or electrification multipliers applied to baseline residential and commercial demand. Methodologies differ in complexity, with some IRPs embedding electrification directly within end-use models, modifying appliance saturation and efficiency assumptions over time, and others applying exogenous load modifiers derived from state building codes or external energy efficiency forecasts (e.g., the CEC IEPR or NEEA regional data). Several IRPs have introduced weather normalized hourly datasets and stochastic heating load simulations to assess resource adequacy under variable climate futures. These techniques improve alignment between load forecasts and resource adequacy modeling by explicitly linking temperature variability to capacity requirements. Generally, building electrification is often modeled as both a growth driver and a load shape shifter, and is understood to reduce natural gas end-use dependence while also introducing new seasonal and diurnal demand risks.

Underlying these efforts is a shift toward shared data frameworks and cross-agency coordination. Utilities increasingly align their electrification assumptions with state transportation departments, building code agencies, and regional efficiency organizations, and reference federal datasets (e.g., NREL's Electrification Futures Study, EIA Annual Energy Outlook) to validate assumptions. This integration of multi-sector data sources represents a fundamental evolution in how planners connect end-use adoption with system-level capacity planning, treating electrification as a core determinant influencing nearly every major planning metric.

C. <u>Resource Adequacy and System Implications</u>

Electrification is fundamentally transforming how resource adequacy is assessed and managed across the Western Interconnection. As loads become more variable, weather-sensitive, and flexible, planners are moving from static reserve margin targets toward probabilistic, multi-slice frameworks that evaluate system performance under a broader range of conditions.

Transition to Probabilistic Frameworks

Traditional deterministic methods anchored to a fixed planning reserve margin (PRM) (e.g., 15%) are being replaced by probabilistic frameworks that explicitly quantify reliability risk through metrics such as loss-of-load expectation (LOLE), loss-of-load hours (LOLH), and expected unserved energy (EUE). Tools such as SERVM, PRAS, and GE-MARS are standard in IRPs and are used to simulate hourly system performance across thousands of scenarios. These tools support 24-hour or multi-slice resource adequacy modeling, which evaluates reliability across discrete time periods rather than a single annual peak. This framework aligns capacity planning with the changing temporal nature of risk (e.g., late-evening net-load ramps driven by EV charging or early-morning heating loads during cold snaps). It also allows planners to better capture the full distribution of reliability risk introduced by load uncertainty, renewable intermittency, and climate volatility.

Planning Reserve Coordination and WRAP Integration

The Western Resource Adequacy Program (WRAP), established by the Western Power Pool, is a coordination mechanism for improving consistency and transparency in resource adequacy planning across the Western Interconnection. Under WRAP, participants conduct forward-showing assessments that measure each entity's resource sufficiency using aligned data, assumptions, and PRAS-based probabilistic modeling, including contributions from imports, storage, and flexible demand across multiple hours and seasons. Some IRPs reference WRAP participation as a driver for methodological alignment, improved data sharing, and greater reserve planning consistency among participants. While voluntary and complementary to existing state and provincial requirements, WRAP's common framework and shared metrics are fostering gradual convergence in resource adequacy planning. This reflects an incremental but meaningful shift toward regionally coordinated resource adequacy planning, where decisions are guided by shared modeling, transparent data, and collective risk optimization rather than isolated reserve thresholds.

D. Peak Demand and Winter Peak Risk

Electrification is reshaping both the magnitude and seasonal distribution of peak demand across the Western Interconnection. Utilities in the West that have historically only planned for a single summer coincident peak, driven mostly by air conditioning and cooling loads, are now seeing growing winter peaks. However, the rapid adoption of transportation and building electrification is now broadening the range of hours and seasons in which system stress occurs.

> **Of Note**
>
> In northern and hydro-dominant areas such as the Pacific Northwest, British Columbia, and Alberta, winter peaks are becoming more pronounced.

In northern and hydro-dominant areas such as the Pacific Northwest, British Columbia, and Alberta, winter peaks are becoming more pronounced as heat pump adoption and declining natural gas end-use increase the system's sensitivity to cold weather. Recent IRPs report measurable temperature-dependent load variability, where several degrees of deviation from normal winter conditions can add hundreds of megawatts of incremental demand at the regional/provincial level. To capture this effect, planners are embedding temperature sensitivity coefficients and stochastic weather scenarios into their load and resource adequacy models, replacing traditional fixed degree day adjustments with probabilistic correlations between temperature and load. These methods allow planners to better evaluate the tail-risk potential of extended cold periods or low hydro conditions that can coincide with increased electrification.

In the southwest and California, summer capacity stress remains dominant, but the shape and timing of risks is changing. High solar penetration has flattened mid-afternoon peaks, shifting the system's critical period to the late evening ramp hours (approximately 6-10 p.m.) when declining solar output coincides with residential cooling, appliance use, and increasingly, EV charging. Evening ramps are particularly sensitive to behavioral uncertainty, such as the extent to which residential charging occurs upon arrival versus under managed or time-of-use programs, which can shift several thousand megawatts of load within a few hours. At the same time, California is experiencing a gradual emergence of growing winter peaks, reflecting higher electric heating adoption and shorter solar days. Many IRPs now incorporate hourly or sub-hourly slice-based modeling to capture these ramp hour dynamics, test system performance across diurnal load transitions, and explicitly evaluate how storage dispatch, demand response, and managed charging programs can mitigate ramp hour shortfalls.

> **Of Note**
>
> California is experiencing a gradual emergence of growing winter peaks, reflecting higher electric heating adoption and shorter solar days.

These electrification patterns produce a spatially and seasonally differentiated reliability landscape across the West. To manage new system peaks, modern planning frameworks must capture the full distribution of reliability risk across hours, seasons, geographic constraints, and behavioral drivers, while also reflecting the compounded influence of electrification, weather volatility, and flexible resource deployment.

E. Flexibility Considerations

As electrification broadens the range of hours and seasons in which system stress occurs, flexibility has become a central focus of modern resource adequacy and system planning. Planners increasingly quantify flexibility needs alongside capacity, assessing a system's ability to ramp, sustain, and recover across critical periods such as late-evening net-load ramps, extended cold spells, and multi-day renewable shortfalls.

Planners are incorporating flexible capacity into long-term analysis through a combination of energy storage, resource coordination, and demand-side management approaches. Energy storage and hybrid resources are being modeled as short duration, fast responding assets that can assist with evening ramps and contingency events, with capacity accreditation based on contributions to reducing loss-of-load probability during higher-risk hours. Hydro and resource coordination are represented through probabilistic dispatch modeling and regional programs, such as WRAP, which can quantify multi-hour and multi-day flexibility. In the Northwest and Canada, several IRPs evaluate coordinated hydro and battery operation to address duration-limited events during winter conditions. Demand-side flexibility, including managed EV charging, dynamic pricing, demand response, and flexible end-uses such as heat pumps and water heating, is typically represented as a controllable or load modifying element within capacity expansion or production cost models.

Collectively, these representations allow planners to examine how supply- and demand-side flexibility contributes to reliability under varying load, weather, and resource conditions. Several IRPs include explicit flexibility indicators, such as net-load ramp duration, hourly dispatchability, or sustained ramp coverage, as complementary planning metrics alongside traditional reliability indicators like LOLE and PRM. By quantifying flexibility in probabilistic terms, planners can evaluate tradeoffs between storage investment, transmission expansion, and demand-side management, helping to inform procurement targets and policy frameworks.

The growing emphasis on flexibility is helping bridge the gap between long-term capacity planning and short-term operational reliability, ensuring that resources selected for resource adequacy needs also deliver measurable flexibility when conditions deviate from forecast norms. In summary, as electrification continues to reshape demand, flexibility will serve as both the constraint and the solution, shifting planning from capacity-centric to capability-based portfolios across the Western Interconnection.

5. Recommendations

As electrification continues to serve as a primary driver of long-term load growth across the Western Interconnection, both utilities and state regulators and policymakers face increasing pressure to standardize methods, improve transparency, and modernize planning practices. IRPs are evolving to better capture the magnitude, shape, and uncertainty of electrified demand, yet wide variation remains in how assumptions are developed, documented, and integrated into resource and transmission planning. The following recommendations highlight priority areas where modeling practices, data coordination, and regulatory oversight can support more consistent and reliable planning outcomes.

A. Recommendations for Utilities

1. Adopt standardized electrification forecasting frameworks.

a. Apply LBNL's seven-step process to develop transparent, scenario-based load forecasts that distinguish between transportation, building, and industrial electrification.[12]
b. Use consistent base-year calibration and document assumptions to support regional comparability.

2. Model flexibility explicitly as a resource.

a. Model EV charging, smart thermostats, and demand response as controllable capacity within resource adequacy modeling and, if beneficial to the utility, develop programs to implement these flexible resources.
b. Expand time-of-use and dynamic pricing to align customer behavior with system conditions.
c. Incorporate probabilistic methods (e.g., LOLE, EUE) and slice-based analysis to capture ramping and seasonal reliability risk.

3. Plan for winter and shoulder-season reliability.

a. Evaluate heating electrification impacts on peak timing and resource sufficiency.
b. Update reserve margins and operational strategies for multi-season risk.

4. Integrate electrification forecasting alongside large loads.

a. Maintain separate modeling tracks (i.e., policy-driven electrification vs. project-driven large-loads) but ensure both inform transmission and generation planning.
b. Coordinate with economic-development agencies to identify pending policy and economic driven demand growth. Compare assumptions against independent benchmarks, such as state EV registration data or building codes.

[12] Lawrence Berkeley National Laboratory (LBNL). New Framework for Incorporating Electrification into Long-Term Electricity Load Forecasts. December 2024. Available at: https://eta-publications.lbl.gov/sites/default/files/2024-12/muni_load_forecasting_guidance_doc_final.pdf

5. Enhance transparency and coordination.

a. Provide clear, side-by-side comparisons of electrification and load growth assumptions across IRP cycles, explaining drivers of major changes.
b. Publish electrification assumptions, adoption scenarios, and flexibility contributions within IRPs.
c. Share data with state agencies, transportation departments, and regional entities such as WPP's WRAP and WECC for consistent regional planning inputs.

6. Invest in data infrastructure.

a. Expand metering granularity and end-use load research to validate modeled electrification profiles.
b. Develop open data standards for EV charging and building loads.

B. Recommendations for Regulators and Policymakers

1. Require electrification scenario inclusion in IRPs.

a. Direct utilities to test at least one high-electrification and one high-flexibility case reflecting state or provincial policy trajectories.
b. Ensure these scenarios inform resource adequacy and transmission plans, not just narrative appendices.

2. Promote coordination through WRAP and WECC.

a. Encourage consistent use of probabilistic adequacy frameworks and shared assumptions on electrification and flexibility across balancing areas.
b. Support data sharing protocols that allow cross-jurisdictional comparison of load growth, flexibility potential, and resource sufficiency.

3. Advance rate-design reform.

a. Encourage utilities to explore time-of-use and dynamic pricing to align customer behavior with system conditions.
b. Pilot EV managed charging programs and tariff structures that reward load shifting.

4. Support integrated planning and permitting.

a. Streamline approval processes for grid upgrades tied to electrification (distribution expansion, interconnection, and storage).
b. Coordinate building, transportation, and energy agencies to synchronize policy targets with utility planning cycles.

5. Align data and modeling requirements.

a. Establish minimum standards for electrification modeling (data sources, time resolution, documentation).
b. Facilitate joint state-utility technical working groups to exchange modeling methods and review results.

6. Limitations

This paper is intended as a synthesis of planning trends, not a comprehensive forecast of future load or reliability outcomes. Key limitations include:

- **IRP-based scope:** This paper relies on publicly available Integrated Resource Plans (IRPs) and supporting materials, which vary widely in scope, modeling sophistication, documentation detail, and update cycles across utilities and jurisdictions. Differences in forecasting methodologies, electrification adoption assumptions, treatment of managed load, weather normalization, and resource adequacy metrics limit direct comparability across plans.
- **Snapshot in time:** The analysis reflects IRPs published between 2021 and 2025 and policies in effect or formally adopted at the time of review. It does not represent a real-time or continuously updated assessment of electrification planning across the Western Interconnection.
- **Policy timing and implementation lag:** State and provincial electrification policies are evolving rapidly, and there are often lags between policy adoption, regulatory implementation, and incorporation into utility planning assumptions. As a result, some IRPs may reflect policy environments that have since changed or are still under development, and future planning cycles may materially differ from the assumptions captured in this paper.
- **No independent validation of forecasts:** This paper does not independently validate utilities' end-use load profiles, electrification adoption trajectories, or probabilistic resource adequacy inputs. Findings reflect how electrification is represented within utility planning frameworks rather than an assessment of forecast accuracy.
- **Regional-level focus:** The analysis emphasizes interconnection-wide trends and does not fully capture distribution-level constraints, feeder-specific impacts, or local infrastructure readiness that may materially affect electrification implementation.
- **Large-load growth treated separately:** While large-load growth is acknowledged as a parallel driver of demand, it is not analyzed in detail here. In some areas, electrification and large-load development may interact in ways that compound local reliability and infrastructure challenges.

7. Conclusions

Electrification is reshaping the Western Interconnection at a system level, altering long-standing assumptions about demand growth, peak timing, and reliability risk. As transportation and building electrification advance under diverse state and provincial policy frameworks, utilities across the West are projecting sustained load growth alongside increasingly complex load shapes, including emerging winter peak exposure and steeper intraday ramps. These trends strain planning approaches historically optimized around summer peak conditions and static reserve margins.

This review of policies, IRPs, and planning methodologies finds that utilities are actively modernizing forecasting and resource adequacy practices, but that substantial variation persists in how electrification is represented. Differences in adoption assumptions, temporal resolution, weather sensitivity, and treatment of flexible demand contribute to inconsistent assessments of reliability risk across the interconnection. In many jurisdictions, electrification-related load growth and load shape impacts appear to be advancing faster than they are fully incorporated into planning frameworks, increasing the likelihood that capacity, flexibility, and transmission needs are understated.

Maintaining system reliability as electrification-driven load growth continues will require closer alignment of utility planning assumptions, supported by improved data sharing, shared modeling practices, and regional coordination. Standardized, scenario-based electrification modeling and clearer treatment of flexibility alongside traditional capacity metrics are critical to improving visibility into future system needs, reducing planning uncertainty and supporting reliable and cost-effective outcomes across the Western Interconnection.

Appendix

List of IRPs Reviewed

Utility	IRP Year
Alberta Electric System Operator	2024
Arizona Public Service	2023
Avista	2025
BC Hydro	2021 w/ 2023 updates
Black Hills Colorado Electric	2022
Black Hills SD&WY	2021
El Paso Electric Company	2025
Idaho Power	2025
Los Angeles Department of Water and Power	2023
Montana-Dakota Utilities	2024
NERC (LTRA)	2024
NorthWestern Energy	2023
NV Energy	2024
PacifiCorp (Rocky Mountain Power)	2025
PacifiCorp (Systemwide)	2025
PacifiCorp (Utah focus)	2025
PG&E (systemwide)	2022
Portland General Electric	2023
Public Service Company of New Mexico	2023
Puget Sound Energy	2021
San Diego Gas & Electric (SDG&E)	2022
Southern California Edison (SCE)	2022
Southwestern Public Service Company	2023
Tri-State Generation and Transmission Association	2023
Tucson Electric Power	2023
UNS Electric	2023
WECC (WARA)	2024
Xcel Energy (Public Service Company of Colorado)	2024