# Future Energy & Resource Needs Study (FERNS)


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NOTICE

Southwest Power Pool (SPP) commissioned The Brattle Group to conduct capacity expansion modeling for the Future Energy and Resource Needs Study (FERNS). This report was prepared for Southwest Power Pool, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants. There are no third-party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

The authors received valuable feedback and input from SPP staff, stakeholders, and working groups throughout the study. We would like to thank SPP staff for project management, leadership, input, and guidance; and the FERNS Technical Review Committee (TRC) members—composed of members of the Future Grid Strategy Advisory Group (FGSAG), Resource and Energy Adequacy Leadership (REAL) Team, Supply Adequacy Working Group (SAWG), Economic Studies Working Group (ESWG), and Consolidated Planning Process Task Force (CPPTF)—for their input and very helpful discussions. We would also like to thank members of the various working groups and meeting attendees who provided feedback on our presentations covering study approach and modeling inputs. Finally, the authors would like to thank their Brattle colleagues who provided modeling support and expert review, including Wonjun Chang, Kai Van Horn, and Kathleen Spees.

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# Executive Summary

Southwest Power Pool (SPP) is navigating a pivotal period of growth and transition as electrification accelerates and carbon-free resources expand across its footprint. Over the years, the regional transmission organization (RTO) has proven to be a leader in safely and reliably integrating a diverse array of renewable resources into its footprint. In 2024, 47% of the energy produced in SPP's region was carbon-free, with most of it coming from wind generation. As load growth continues to accelerate at unprecedented levels, however, the SPP region will require substantial additional generation and transmission investments to maintain grid reliability.

The Future Energy and Resource Needs Study (FERNS) examines anticipated SPP resource additions, resource adequacy challenges, and cost implications at the intersection of two key industry drivers: demand growth and increasing shares of intermittent, carbon-free resources such as wind and solar. SPP retained The Brattle Group (Brattle) to simulate optimal generation and zonal transmission expansion through 2050 while proactively analyzing resource adequacy challenges associated with 15 meteorological years, including winter storms, heat waves, renewable droughts, and weather-correlated generation outages.

The simulations project that **SPP will be able to maintain resource adequacy in a cost-effective and affordable manner**. Using Brattle's Weather Resource Adequacy Sampling (WRAS) approach, the simulations show that—even at much higher levels of intermittent generation—future resource adequacy challenges can be met through a combination of retaining (or replacing) existing fossil generation, taking advantage of the load serving capability of intermittent resources, and adding new dispatchable resources, such as battery storage. While the annual energy generated from fossil-fueled resources is projected to decline to only 10% to 30% of the total energy produced in the SPP region by 2050, the study indicates that the same fossil-fueled resources will still account for 40–60% of the capacity available during resource adequacy challenges. In other words, conventional resources will continue to play a vital role in ensuring regional reliability even as carbon-free resources account for an increasingly larger share of annual energy production.

Even without federal tax credits or similar other clean energy policies, renewable generation is projected to grow significantly because of its abundant availability in the SPP footprint and declining technology costs—resulting in approximately 70% of SPP's annual energy being generated by carbon-free resources by 2050. If existing production tax credits remain available or are readopted, the share of carbon-free generation is projected to reach approximately 90% by 2050. In each case, SPP is projected to be able to serve growing loads reliably and affordably through a combination of fossil-fueled generation, wind, solar, nuclear, hydro, and battery storage resources.

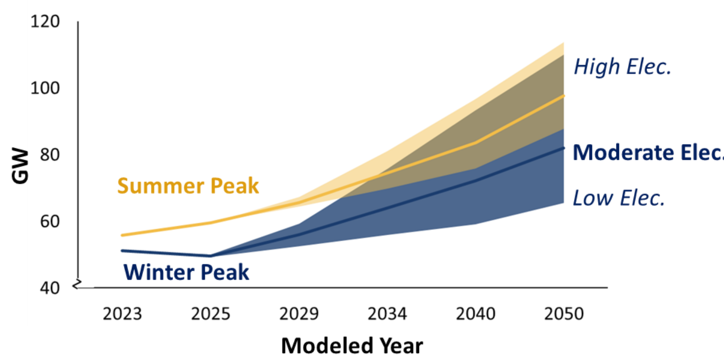
Futures in which little new fossil generation is added to serve growing electrification demand require both (1) more interzonal transmission connecting resource-rich renewable energy areas to load centers and (2) new wind, solar, and storage resources sited at locations closer to load centers. Transmission investment is thus an integral part of a cost-effective resource-adequacy solution, particularly in high wind and solar futures. The optimal expansion of transmission in the SPP footprint is, however, sensitive to how the cost of new transmission compares to the cost (and quality) of developing new generating resources closer to load. In scenarios with fewer investments in new fossil-fueled generation, more investments are made to develop renewable resources, storage, and transmission to connect renewable-energy-rich areas to load centers.

To explore these questions in greater detail, FERNS analyzed five SPP-defined scenarios as shown in Figure ES-1 below. The scenarios cover moderate and high carbon-free resource shares (ranging from approximately 70% to 90% by 2050) and low, moderate, and high load growth assumptions (with peak load growing by 55% to over 100% by 2050), as shown in Figure ES-2.

**FIGURE ES-1: FERNS STUDY SCENARIOS**

| | | Carbon Free Resource Shares | | |
|---|---|---|---|---|
| | | Low | Moderate | High |
| Electrification | Low | | A1 | B1 |
| | Moderate | | A2 | B2 |
| | High | | | B3 |

**FIGURE ES-2: SPP PEAK LOAD SCENARIOS**




The study projects that SPP will be able to maintain resource adequacy in each of five scenarios with generation additions that result in total SPP installed generation capacity ranging from 170 GW to 340 GW by 2050 (as shown in Figure ES-3 below). A supplemental land use study confirms that the SPP footprint has sufficient developable low-impact land to build the resources needed in each of the FERNS scenarios.

As shown in Figure ES-4 below, meeting the projected load growth and resource adequacy requirements is projected to be possible at reasonable costs, with only modest increases or even slight declines in the (inflation-adjusted) average $/MWh cost of modeled generation and transmission. This is achievable despite the high investment needs due to the significant load growth in combination with avoided fuel costs and tax credits (if available). The scenarios with high carbon-free resource shares show slight declines in $/MWh costs due to the assumed continued availability of federal tax credits, which are particularly valuable in the SPP footprint due to the high quality of wind and solar resources.

FIGURE ES-3: SPP TOTAL INSTALLED CAPACITY (GW)

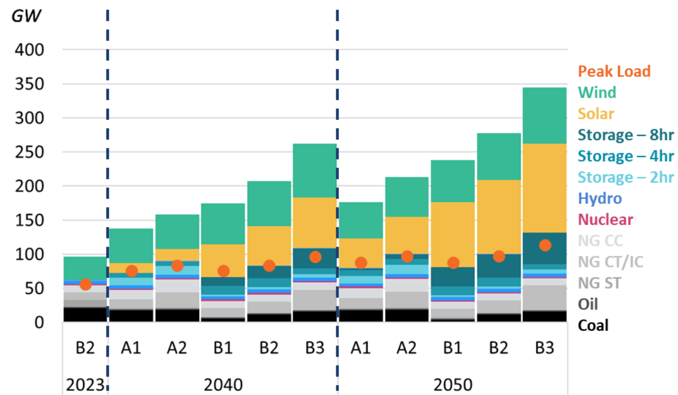
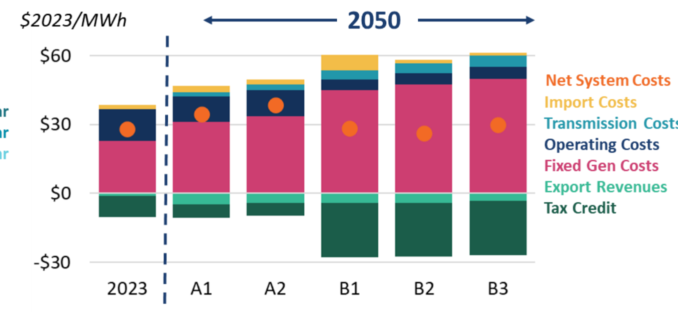



FIGURE ES-4: SPP $/MWH SYSTEM COSTS




These and other key FERNS takeaways are summarized in the text box below. The remainder of this report then describes the FERNS study approach in Section I, followed by a discussion of results in Section II, and concludes with key takeaways in Section III. Three appendices provide additional detail on modeling inputs and approach (Appendix 1), detailed scenario results (Appendix 2), and the land use study (Appendix 3).

## KEY FERNS TAKEAWAYS

- In scenarios with high load growth and high shares of renewable generation, SPP is projected to maintain resource adequacy in a cost-effective and affordable manner if fossil-fuel generation capacity is retained (or replaced) for reliability purposes and sufficient new resources, including storage, are added to the SPP system.
- A projected $88–$263 billion of generation investments will be needed to support SPP's load growth through 2050. This is possible without significant rate increases (in inflation-adjusted terms) due to load growth and fuel-cost savings, especially if federal tax credits (or similar renewable generation support) remain available.
- Between 70% and 90% of SPP's annual energy is projected to be generated from renewable resources by 2050, though conventional generation is expected to continue to serve a large share of SPP's resource adequacy needs, representing 40–60% of the region's accredited capacity. This is a function of technology costs, natural gas prices, and the availability of tax credits (or similar policies).
- Solar generation is projected to outcompete wind generation. By 2050, 20–48 GW of new wind generation is expected to be added, which compares to 42–130 GW of new solar generation. As solar generation expands, 22–59 GW of battery storage is projected to be cost-effective (and often co-located) to maintain resource adequacy.
- 4–21 GW of new regional transmission capacity (between SPP zones) is projected to be cost-effective by 2050, necessary to support the delivery of generation to load centers.
- Resource adequacy challenges evolve over time to be more frequent during: (a) winter months (particularly in high electrification futures) and (b) the early evening hours (after sunset). This implies that winter planning reserve margins will need to be significantly higher than summer reserve margins, due to low solar capacity values and high temperature-correlated fossil outages in the winter.
- The effective load carrying capability (ELCC) value of solar and short-duration storage resources is projected to decline over time, while the ELCC of wind resources increases slightly. Even the ELCC of 8-hour storage declines in the high renewable generation scenarios, indicating a need for long-duration storage. Interties with neighboring regions offer valuable resource adequacy and extreme-weather resilience benefits to the SPP footprint.
- SPP has sufficient available land to accommodate the projected 60–180 GW of wind and solar generation additions through 2050 in all scenarios evaluated.
- SPP is projected to become a more significant net exporter by 2050, particularly in the high renewable generation scenarios, due to the high-quality of renewable generation in the region.

# I. Study Approach

FERNS uses Brattle's in-house capacity expansion model, gridSIM, to simulate the cost-optimal future resource mix that ensures reliability under a range of carbon-free resource and demand electrification scenarios. FERNS modeling examines the generation investments, regional and interregional transmission, resource adequacy impacts, and system costs that SPP may face under five SPP-selected scenarios of different decarbonization and electrification (load growth) pathways.

## A. Study Overview and Scenario Design

In the coming decades, SPP will face extensive energy system changes if carbon-free resources develop at continued current rates and electrification drives unprecedented demand growth. The rate of renewable generation deployment and electrification adoption depend on many uncertain factors such as technology costs and supply chain constraints, resource costs (including federal, state, or corporate support), commercial and industrial demand, and customer technology adoption. To explore the implications of these trends, SPP has developed five FERNS scenarios, as shown in Table 1, with varying degrees of electrification and carbon-free resource deployment to study the range of cost and resource adequacy impacts under uncertain futures. Brattle was retained to simulate through 2050 the likely generation mix, investment needs and overall costs, and resource adequacy implications associated with these five scenarios. FERNS relies on detailed capacity expansion modeling to examine key insights around future impacts on the SPP electric system but does not analyze a fully decarbonized SPP scenario. While analyzing resource adequacy challenges and co-optimizing regional transmission and generation expansions, these simulations do not replace the need for more detailed nodal production cost modeling for transmission planning or the detailed probabilistic simulations necessary to determine the frequency of loss of load events for near-term resource adequacy planning.

**TABLE 1: THE FIVE FERNS SCENARIOS**

| Electrification | Carbon-Free Generation Share: Low | Moderate | High |
|---|---|---|---|
| Low | | A1 | B1 |
| Moderate | | A2 | B2 |
| High | | | B3 |

FERNS includes two moderate carbon-free generation share pathways (Scenarios A1 and A2) that explore a future without the continuation of current federal tax credits (Investment Tax Credit, ITC, or Production Tax Credit, PTC) or comparable renewable support that could lead to SPP producing 70% carbon-free resources by 2050. Three high carbon-free generation scenarios (B1, B2, and B3) reach approximately 90% carbon-free generation by 2050 under the assumption that federal tax credits (or equivalent state or corporate support for renewable generation) continue through 2050 at their current levels.

## B. Projected Load Growth

Load forecasts for three FERNS electrification scenarios—low, moderate, and high—were developed by Evolved Energy Research (EER) for SPP through 2050.[1] For each scenario, EER developed load forecasts for 2023, 2025, 2029, 2034, 2040, and 2050—each for fifteen different meteorological years (reflecting 2006–2020 historical weather conditions). Because the 15 SPP-selected historical "weather years" did not include the severe winter storms SPP experienced in 2021 and 2022, we separately added a proxy three-day winter storm event to each study year, assuming SPP would encounter such winter storms every 5–10 years.

The low electrification scenario results in peak demand growing by 56% through 2050, the moderate scenario forecasts an increase of 75%, and high electrification scenario projects an increase of 104% between 2023 and 2050. In all scenarios, SPP is projected to remain a summer peaking system on a SPP-wide gross load basis, although individual SPP zones, especially in the north, will experience dual peaking or winter peaking conditions. Based on SPP's guidance, and

1 Additional documentation on demand electrification drivers can be found in the Future Load Scenarios for Southwest Power Pool (September 2024) report prepared by Evolved Energy Research. All scenarios account for increasing data center demand, but do not account for hydrogen electrolysis demand impacts.

as shown in Table 1 above, we analyze five scenarios: (a) to assess the impacts of moderate carbon-free resource development for the low and moderate electrification futures (Scenarios A1 and A2); while (b) evaluating the implications of high carbon-free resource development for low, medium, and high electrification demand growth futures (Scenarios B1, B2, and B3). Appendix 1 provides more detail about the scenario-based study assumptions.

The hourly load shapes provided by EER are assumed to be inflexible (or reflect load shapes net of load flexibility) as the FERNS scope did not include exploring the value that **load flexibility** would provide to the SPP system to cost-effectively meet a portion of the projected future resource adequacy requirements. Grid flexibility potential studies performed for other regions, however, illustrate its large likely potential and value—estimating that load flexibility, once fully mobilized, might be able to address up to 25% of the 2040 system peak.[2]

## C. Capacity Expansion Modeling Approach

The study was undertaken with gridSIM, The Brattle Group's capacity expansion model to examine resource adequacy under future system conditions, such as is necessary for FERNS. The gridSIM optimization model minimizes the costs of serving future system needs (e.g., electrified demand) with a combination of existing generating assets, new resources, and additional transmission infrastructure. The gridSIM model co-optimizes over the study timeframe (2023 through 2050 for FERNS) annual capacity expansion, generation retirements, hourly production cost, and interzonal transmission expansion to find the cost-minimizing solution for meeting system requirements.

FERNS simulates the evolution of SPP market conditions between 2023 and 2050 for the SPP-selected intermediate years. As illustrated in Figure 1, the SPP footprint is modeled as six internal zones based on the 2023 LOLE study.[3] The gridSIM setup represents aggregated load and generation assets in each of the six zones with transfer capabilities (subject to the simultaneous export and import capabilities used in SPP's LOLE study, but economically expandable in FERNS simulations) between the SPP zones. In addition to the SPP footprint, the

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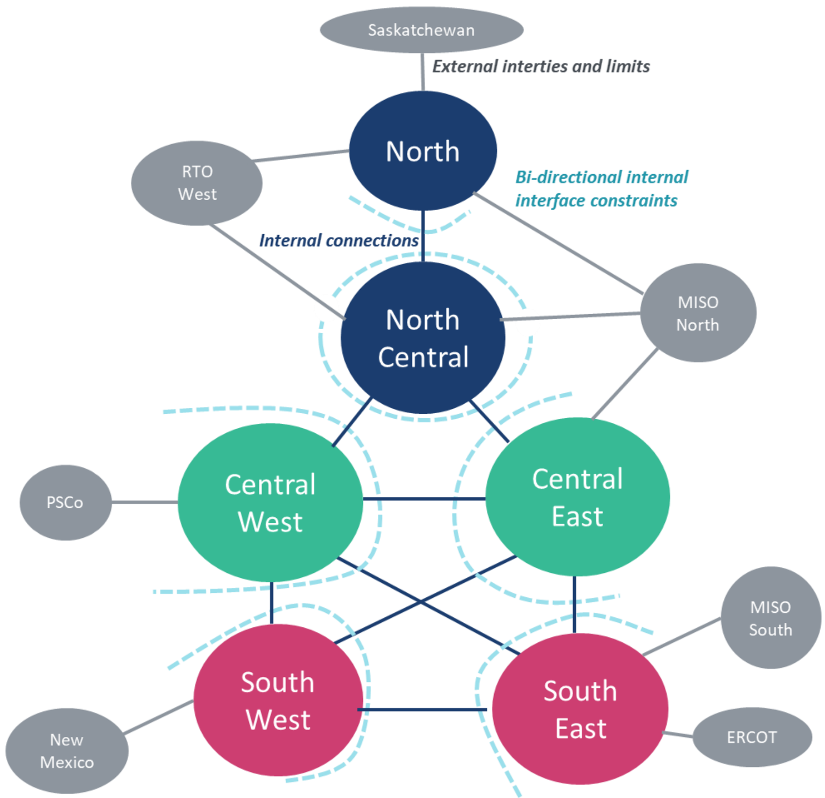
2 See Hledik, Ramakrishnan, Peters, Edelman, and Savage Brooks. "New York's Grid Flexibility Potential." The Brattle Group, prepared for NYSERDA and NY DPS, January 2025. https://www.brattle.com/insights-events/publications/brattle-experts-conduct-a-study-to-determine-new-yorks-grid-flexibility-potential-in-2030-and-2040/

3 FERNS uses the six 2023 LOLE study zones that divide each of SPPs three transmission zones in half. The SPP bubbles in the zonal diagram (North, North Central, Central West, Central East, Southwest, and Southeast) are colored in pairs based on the SPP transmission zone.

FERNS simulations also capture SPP energy transfers, and geographic diversity benefits, with seven neighboring electricity market regions based on SPP-provided transfer capabilities between the SPP footprint and each neighboring zone. More detailed information about the simulated topology is provided in Appendix 1.

**FIGURE 1: FERNS ZONAL TOPOLOGY**




FERNS considers only **generation technologies that are currently commercially available** to meet SPP's future system needs. This includes fossil generation (coal, oil, and natural gas), onshore wind, solar, battery energy storage (2hr, 4hr, and 8hr duration), hydro, nuclear, and biofuel assets. FERNS did not consider hydrogen-fueled combustion turbines, long-duration storage, or other clean dispatchable technologies like small modular nuclear reactors as potential candidates to meet future system needs. While these evolving resources could play a large role in SPP's future resource adequacy solution, the FERNS effort focuses on examining SPP's ability to meet future reliability needs based on technologies available today.

In addition to building new generation resources within each of the six SPP zones, FERNS considers **transmission expansion between SPP zones** as a potential solution to minimize total costs to meet resource adequacy requirements. Interzonal transmission plays a large role in integrating high-quality wind and solar generation in the western portions of SPP to the growing load centers in the eastern SPP footprint. The **co-optimization of transmission and generation investment** in gridSIM provides unique insights for use in future SPP grid planning efforts. Appendix 1 provides additional detail on the generation and transmission assumptions used in the study.

## D. Modeling Resource Adequacy

FERNS takes an innovative approach to modeling resource adequacy by capturing challenging conditions from variable renewables, dynamic load, and weather-dependent fossil generation outages in a highly decarbonized and electrified future on an hourly basis across a wide range of weather years. Traditional approaches to resource adequacy in expansion planning models rely on "weather-normal peak load plus a planning reserve margin" and assume the future capacity value of different resource types as input assumptions. Since neither the required planning reserve margin nor the capacity accreditations (such as the ELCC) of different resources are known for future market conditions with varying load profiles and resource mixes—such as 70% to 90% of SPP generation from intermittent wind and solar generation—traditional capacity expansion modeling efforts may not produce realistic results for a reliable future supply mix.

To avoid this shortcoming of traditional capacity expansion models, FERNS deploys Brattle's **Weather Resource Adequacy Sampling** (WRAS) tool to create a single proxy year for each future model year that captures the full range of extreme load, low renewable, and high fossil-outage conditions for all 15 SPP-supplied weather years and winter storm periods.[4] As summarized in Figure 2 (and explained in more detail in Appendix 1), the WRAS proxy year captures the high temperature correlated thermal generation outages, renewable droughts, and high load conditions (heat waves and cold snaps) encountered over the course of all 15 weather years and winter storms through twenty-six 72-hour (3-day) proxy periods—with appropriate weightings for the frequency of each 3-day period's occurrence in the 15-year weather sample.

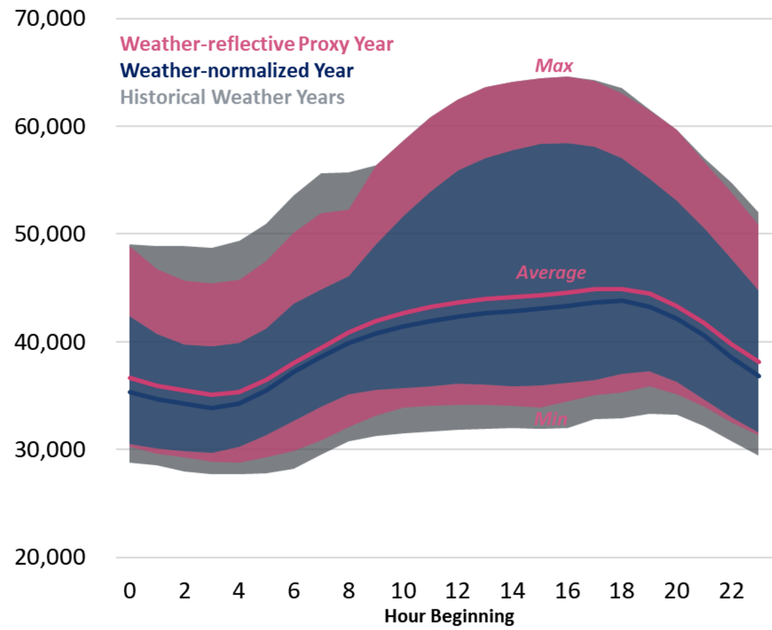
4 Weather conditions represent 2006–2020. 2021 and 2022 were not included in the sample consistent with the EER Demand Electrification report, despite being key risk years with winter storms Uri and Elliot. We adjusted WRAS parameters with input from SPP's Technical Review Committee and their analysis of SPP conditions under winter storm conditions to add a three-day winter storm period (with a likelihood off occurring once every 5–10 years) to each proxy year.

**FIGURE 2: BRATTLE'S WEATHER RESOURCE ADEQUACY SAMPLING (WRAS) TOOL**


The WRAS proxy year approach captures the full range of weather conditions over the 15-year sample, including major winter storms, while allowing for a computationally efficient model. Without the WRAS proxy year approach, the model would either need to simulate 15 full weather years of 8,760 hourly data for every study year through 2050 (which would be computationally infeasible) or rely on traditional weather-normalized, single-year simulations (which would not capture weather-related resource adequacy risks).

Figure 3 illustrates the range of daily SPP-wide loads across 15 weather years for: (1) the 2029 FERNS forecast across all 15 weather years (grey range); (2) a weather-normalized year (dark blue range); and (3) the WRAS proxy year of 26 three-day periods (pink range). The 26 periods consist of 6 three-day periods for each of the four seasons, one extreme summer heat-wave period, and one extreme winter cold-snap period. As shown in the figure, the WRAS proxy year creates hourly daily load shapes that closely capture the full range of daily load shapes across all weather years, particularly from a resource adequacy (high-load) perspective. As further shown in Figure 4 for the example of the Central-East zone of SPP, the adjusted net load duration curve (i.e., gross load adjusted for weather-correlated renewable generation and outages) of the proxy year (teal line) closely matches that of the entire set of 15 weather years (orange line). More detail about the calibration quality of the WRAS proxy year—in terms of renewable generation profiles, net load conditions (adjusted for both renewable generation and forced generation outages), and net load diversity across the SPP footprint—is provided in Appendix 1.

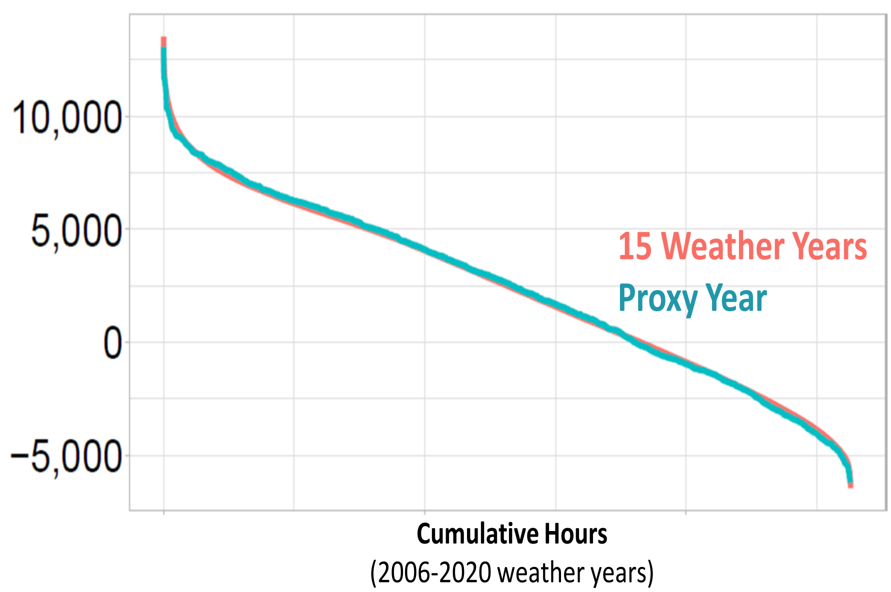
**FIGURE 3: RANGE OF DAILY SPP-WIDE 24-HOUR GROSS LOADS IN 2029 (MW)**




Note that the axis starts at 20,000 MWh to visually distinguish the different datasets

**FIGURE 4: SPP CENTRAL-EAST NET LOAD DURATION CURVE FOR 2029 (MW)**

(Adjusted for renewable generation and temperature-correlated generation outages)




By modeling hourly resource adequacy needs for future proxy years that reflect the full set of challenges associated with 15 weather years and winter storm periods, it is not necessary to pre-specify planning reserve margins and ELCC values of different resource types (such as solar, wind, and battery resources). Rather, the resource adequacy value of all resource types (including fossil generation, considering weather-correlated outages) are captured endogenously in the simulations. To do so, FERNS defines hourly resource adequacy needs as hourly loads plus a 5% capacity (operating reserve) margin, which needs to be maintained for the full range of challenging system conditions (such as heat waves, cold snaps, renewable droughts, and high generation outages) that may reoccur within the simulated weather years.

The generation capacity available to meet zonal and SPP-wide resource adequacy requirements includes dispatchable thermal resources not on outage (scheduled or forced due to temperature modeling), renewable generation output, battery storage assets with sufficient charge, or sufficient transfer capability to import surplus generation capacity from zones within the SPP footprint. Consistent with the current SPP resource adequacy framework, non-firm imports of energy from SPP's neighboring regions (e.g. MISO, RTO West, ERCOT, etc.) are not assumed to contribute to the specified hourly resource adequacy requirements. However, FERNS simulations do capture the economic and resilience value of geographic diversity between SPP and neighboring regions by allowing hourly energy trading over SPP's interties if cost effective to serve SPP demand with imports (and neighboring regions have available generating capacities) or export SPP generation to neighboring regions.

A key benefit of this approach is the endogenous modeling of available capacity on an hourly basis across the full range of expected resource adequacy challenges, which eliminates the need to assume future ELCC values for renewable generation and storage—a difficult task particularly in future years with different load profiles, high renewable generation shares, and a varying mix of wind, solar, and storage resources.

As a result of the modeled resource additions, each FERNS generation expansion scenario is resource adequate on an hourly basis at both a zonal and SPP-wide level. The FERNS modeling uses a $50,000/MWh "resource adequacy violation charge" to represent tradeoffs between adding generation capacity or allowing for load shedding (or operating reserve depletion) during the most challenging hours across all weather years. At this level of charge, resource adequacy violations occur only during the modeled extreme winter periods (i.e., once every 5–10 years) across the FERNS scenarios. The RA violation charge has to exceed typical estimates of the Value of Lost Load (VOLL) because the 1-in-10-year resource adequacy standard is more stringent than what could be justified economically based on VOLL.

## E. Additional Modeling Inputs

All assumptions used in FERNS were developed in close collaboration with SPP staff, the FERNS Technical Review Committee, and input from several SPP working groups (REAL, SAWG, FGSAG, ESWG, SPC). FERNS inputs are, where applicable, consistent with the assumptions of recently completed or ongoing SPP efforts, such as Integrated Transmission Planning (ITP) 2025 and the 2023 LOLE Study and supplemented with public data as needed. Table 2 summarizes model inputs and key sources. Additional documentation on the modeling approach, data inputs, and assumptions is provided in Appendix 1.

**TABLE 2: SUMMARY OF KEY FERNS INPUTS AND DATA SOURCES**

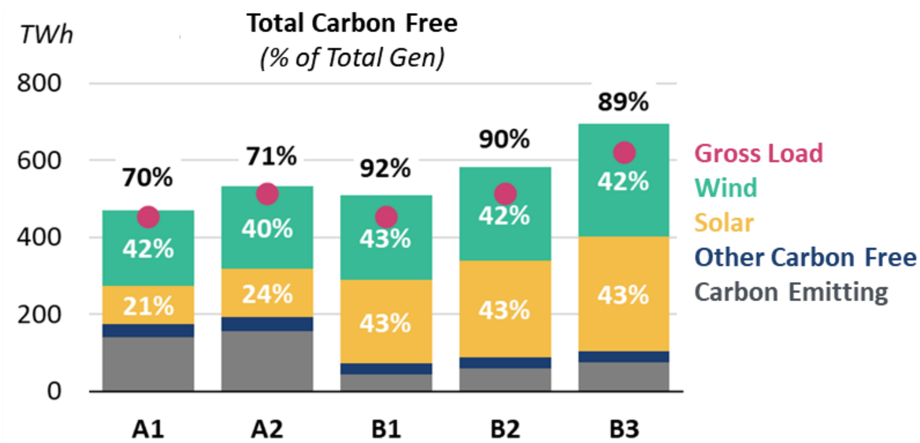
| Data Element | Description and Source Notes |
|---|---|
| **Energy Zones** | Six internal energy zones consistent with 2023 LOLE Study zones (North, North Central, Central West, Central East, Southwest, and Southeast) |
| **Transmission Topology and Limits** | Interface limits between each internal zone and the rest of SPP consistent with 2023 LOLE study limits (ATC and FCITC); the simulations will optimally expand the transmission limits based on cost assumptions developed from SPP transmission cost estimates and MISO forward looking costs |
| **Imports and Exports** | Fixed import and export limits with neighboring regions provided by SPP staff. Hourly energy transfers based on simplified modeling of external zones to capture regional variations in load, renewables (over the same 15 weather years and cold snaps) and associated diversity benefits |
| **Load Growth** | Low, moderate, and high scenarios developed by Evolved Energy Research (EER) for SPP FERNS Demand Electrification that represents a range of electrification scenarios and 15 weather years |
| **Hourly Load Shapes** | Hourly shapes developed by EER for SPP FERNS Demand Electrification that vary by (weather) year, SPP zone, end-use, and scenario for 2023, 2025, 2029, 2034, 2040, 2050 |
| **Existing Generator Data** | SPP data (2025 ITP) for existing units' capacities, heat rates, and additional operational characteristics by region |
| **Scheduled Additions/Retire-ments (near term)** | SPP data (2025 ITP) and Interconnection Queue studies to identify resource decisions already made (as model input) by capacity, location, date. (Necessary additional future generation additions and retirement decisions are optimized by the model) |
| **Cost Trajectory for New Generation** | Capital, fixed, and variable cost projections for new generators by resource type and SPP zone from SPP IHS forecasts; zonal costs and intra-zonal transmission adders as function of resource availability and transmission headroom/cost by zone informed by SPP interconnection studies |
| **Hourly Renewable Generation** | Hourly renewable profiles for all SPP zones and external regions, for all 15 weather years available in the load dataset, based on Imperial College London ("Renewables.Ninja") dataset and benchmarked to National Renewable Energy Laboratory (NREL) regional values |
| **Fuel Prices** | Natural gas, coal, and oil prices (by SPP zone) from SPP IHS forecasts and 2024 and 2025 ITP; additional fuel types supplemented from other public sources like the NREL |
| **Reserve Margin and Resource Adequacy Framework** | FERNS uses an hourly approach to determine resource adequacy needs (based on hourly loads, operating reserves, renewable profiles, and generation outages associated with 15 weather years and cold snaps). FERNS defines RA requirements as hourly load plus a 5% capacity (operating reserve) margin, which needs to be maintained across the full range of challenging system conditions (such as heat waves, cold snaps, renewable droughts, and high generation outages). A $50,000/MWh "resource adequacy violation charge" represents tradeoffs between adding generation capacity or allowing for load shedding (or operating reserve depletion) approximately once in ten years during the most challenging hours across all weather years |
| **Tax Credits and Clean Energy Policies** | IRA-based PTC for solar and wind (and ITC for battery storage) or equivalent (state or corporate) support, assumed for the entire study horizon in Scenarios B1, B2, and B3. Assumed eliminated for Scenarios A1 and A2. No other clean energy policies are assumed for the SPP footprint |

# II. Results and Key Findings

## A. Generation Capacity

Today, SPP already generates 47% of its electrical energy from carbon-free resources.[5] The FERNS analysis projects continued development of wind, solar, and storage resources to reach SPP-wide carbon-free energy shares for 2050 ranging from approximated 70% of total annual generation in the moderate carbon-free generation scenarios (A1 and A2) to approximately 90% in the high carbon-free generation scenarios (B1, B2, and B3), as shown in Figure 5 below.

**FIGURE 5: SPP-WIDE ENERGY GENERATED BY RESOURCE TYPE IN 2050[6]**




All scenario results yield comparable shares of wind resources (approximately 40% of total generation output) in 2050, but vary significantly in fossil and solar generation shares—with 43% solar generation in Scenarios B1, B2, and B3 (assuming continued tax credits or equivalent state or corporate renewable generation support policies), but only half as much solar generation in Scenarios A1 and A2 (without further tax credits or equivalent support). Without federal tax credits (or comparable support), SPP is projected to generate approximately 30% of annual energy from fossil resources by 2050 (A1, A2), whereas that share is only 10% with continued support for renewable generation and storage (scenarios B1, B2, and B3). As also shown in Figure 5, in these "B" scenarios with high-renewable generation, SPP becomes a

5 Southwest Power Pool, Fast Facts: An Overview of the SPP System at https://www.spp.org/about-us/fast-facts/

6 Other carbon free resources include nuclear, hydro, and biogen. Total (%) shows % of total generation from carbon free resources.

significant net exporter of renewable energy—as indicated by the difference between SPP gross load (pink dots) and total SPP generation (the top of the bars).

### KEY TAKEAWAYS

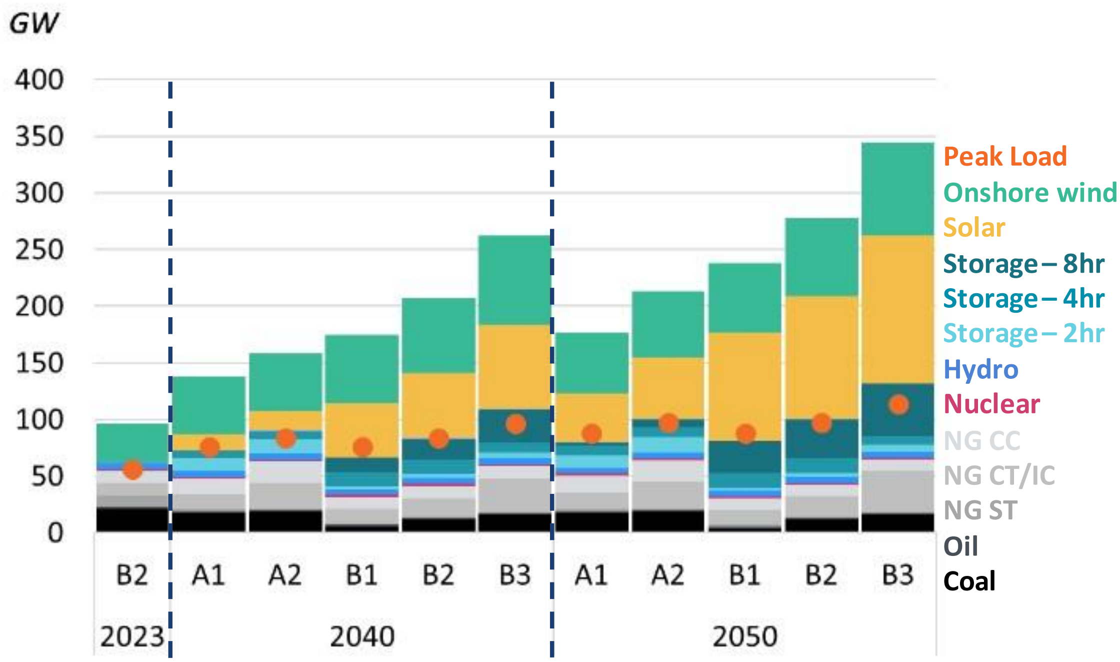
**Assuming federal tax credits (or equivalent state or corporate renewable generation support policies) continue, SPP is projected to generate approximately 90% of annual energy from carbon-free resources by 2050. Without federal tax credits (or similar policies) SPP will reach 70% carbon-free generation. Most of the existing fossil generation capacity is retained but only between 2 and 26 GW of new fossil generation is projected to be developed in SPP by 2050—in part because renewables and storage are more cost effective based on SPP's projected technology and fuel costs, particularly if tax credits remain available.**

Each of the five FERNS scenario results in different optimal mix of generation technologies, all of which are able to maintain reliability, even in the highest demand and renewable generation futures. However, to meet the varying levels of projected load growth and maintain resource adequacy, SPP will need to add substantial amounts of new generating capacity.

In the near term, through the late 2020s, all scenarios have comparable installed capacity mix due to already-scheduled retirements and already-planned generation additions. As shown in Figure 6 below, the installed capacity mix investments start to diverge in the 2030s for the different FERNS scenarios with significant differences by 2040 and 2050.

The study results project that most of SPP's conventional generation capacity will be retained (or replaced) through 2040 and 2050 in the moderate carbon-free share (Scenarios A1, A2) and highest demand growth (B3) futures, even if less energy is generated annually from that capacity in the scenarios with continued federal tax credits. Only in the high carbon-free scenarios with low or moderate load growth (Scenarios B1 and B2), is a portion of SPP's existing installed level of fossil generation capacity replaced with lower-cost renewable and storage resources as shown in Figure 6.

FIGURE 6: SPP TOTAL INSTALLED GENERATION CAPACITY ACROSS FERNS SCENARIOS




Between 2040 and 2050, an increasing amount of solar capacity is added in all Scenarios (particularly B1, B2, and B3)—and paired with battery storage to maintain reliability. As also shown in Figure 6, the SPP region is projected to rely on shorter (2–4 hour) duration storage (paired with less solar capacity) in the "A" scenarios and longer (8+ hour) duration storage in the "B" scenarios. Figure 6 further demonstrates that installed wind generation capacity is very similar across the scenarios, suggesting SPP will reach wind saturation regardless of federal renewables support. Appendix 2 provides additional detail for these generation-related simulation results.

The significant projected solar generation development during the 2040s (with very little new wind generation) is in part driven by SPP cost assumptions. As documented in Appendix 1, SPP's generation technology cost assumptions are on the low end for both solar and storage (compared to publicly available cost projections), but on the high end for wind generation. In combination with SPP's relatively high gas price projections, these assumptions will be a significant determinant of the FERNS optimal resource mix results. For example, lower gas prices and higher solar costs would reduce the share of solar and storage but increase reliance on natural gas and wind generation. Sensitivity analyses would be necessary to understand the extent of the trade-off between cost assumptions and optimal resource mix.

### KEY TAKEAWAYS

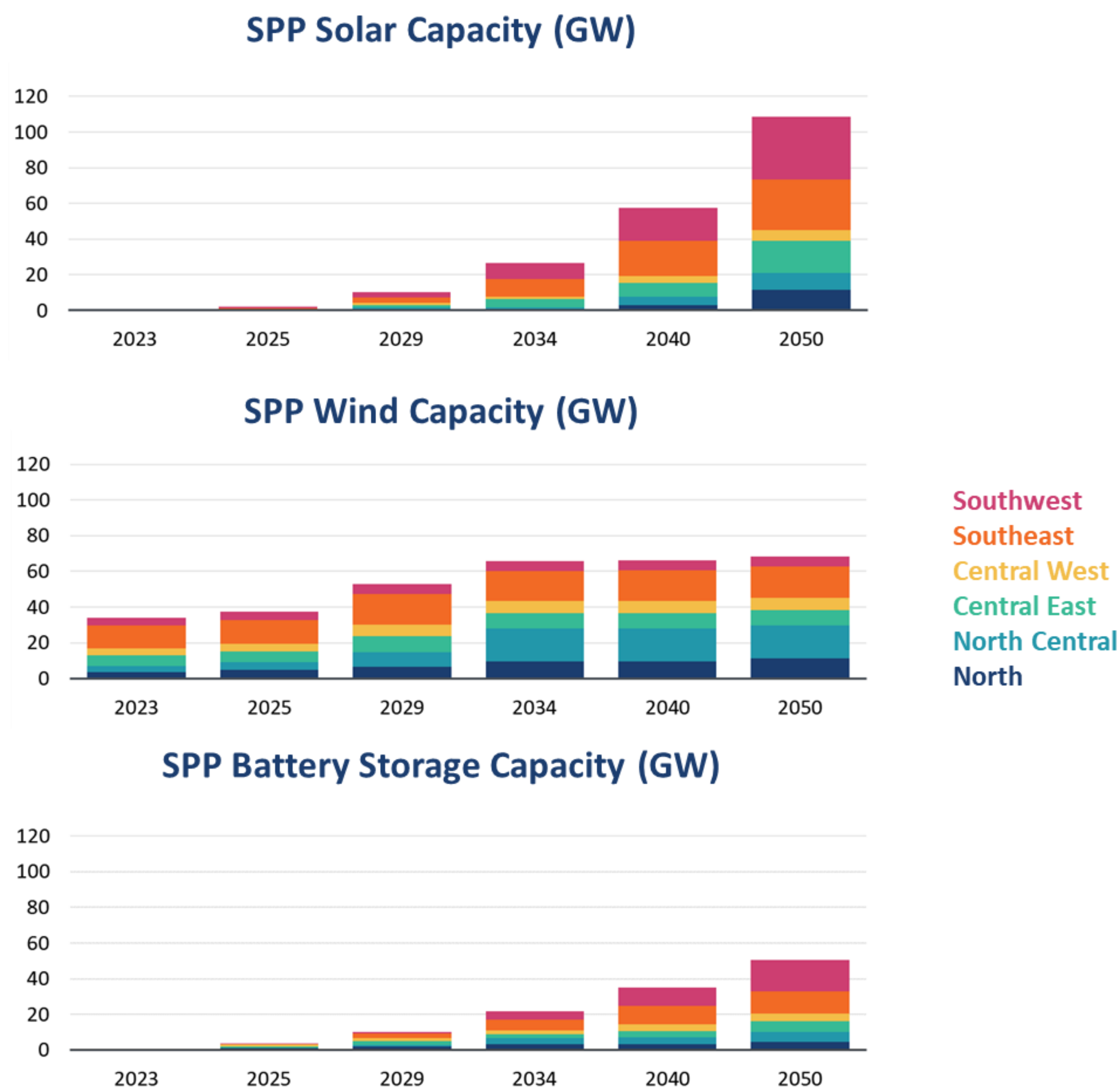
**The SPP footprint will retain or replace installed fossil generation capacity in most (and add 2–26 GW of conventional generation in some) of the scenarios through 2050. Beyond that, wind generation is the primary new resource added through 2035, after which solar tends to outcompete wind. Across SPP, 20–48 GW of new wind and 42–130 GW of new solar capacity is projected to be added by 2050, with significant variances across the FERNS Scenarios. Because these results depend on SPP's technology and fuel cost assumptions, future modeling efforts should explore sensitivities around cost inputs.**

**Adding solar resources increases the value of battery storage, which could lead to 22–59 GW of storage capacity installed by 2050. Results indicate that longer duration storage will be necessary in high-renewable futures starting in 2040 (which the simulations approximate by overbuilding 8-hr storage).**

Today, most of SPP's wind generation is concentrated in the Southeastern portion of the footprint, with some in Central East and the rest dispersed throughout the other zones. The eastern zones account for the highest shares of SPP load, and there is little solar and storage capacity installed throughout SPP today.

As Figure 7 shows for Scenario B2, the SPP generation mix is projected to evolve over time such that wind additions will plateau in the mid 2030s, after which additional capacity is developed closer to loads in the Southeast and in North Central, to take advantage of high-quality resources. Starting in the mid 2030s, a large amount of solar generation is projected to be developed—reaching 110 GW for the SPP region by 2050—concentrated primarily in the southwestern, southeastern, and central east zones of the SPP footprint.

FIGURE 7: TOTAL INSTALLED RENEWABLE GENERATION AND STORAGE BY ZONE (SCENARIO B2)




Storage is economically added in solar-rich regions to take advantage of the daily generation patterns. The optimal development of storage resources is thus highly correlated with zonal solar generation, pointing to the colocation of solar and storage resources to reduce transmission needs and overall costs. Solar and storage resource investments in the Southwest, however, are optimally combined with transmission capability to allow additional exports of southwestern generation to serve load centers in the other SPP regions. Additional zonal resource mix results are included in Appendix 2 for the remaining FERNS scenarios.

## B. Land Availability

FERNS capacity expansion results are validated with a land-use analysis to ensure the projected generation expansion has feasible availability for such resource development within the SPP footprint. The land-use analysis, attached as Appendix 3, relies on NREL's geospatial dataset[7] and The Nature Conservancy's Power of Place data[8] to conduct a viability screening of the FERNS generation development results. The NREL dataset provides generation potential for solar and wind accounting for certain physical land-use limitations, while the Nature Conservancy data identifies buildable areas for each resource type based on a wide range of environmental and social development restrictions.

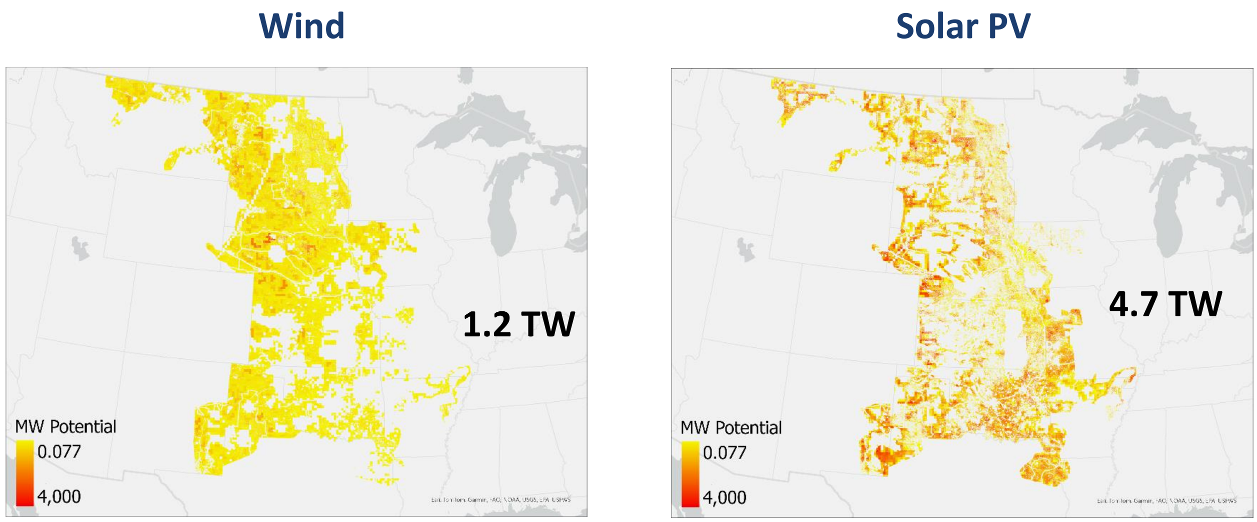
The land-use study estimates the total wind and solar capacity that could be developed in each of the six SPP zones under different land use restrictions. While additional analysis will be needed to map land availability to the actual (nodal) locations of the SPP transmission grid, our analysis shows that SPP wind and solar generation development, on aggregate within any of the six SPP zones analyzed, will not be limited based on the availability of developable land even with stringent land-use restrictions. All FERNS projected wind and solar capacity developments are well below what would be possible even considering fairly high land-use restrictions.

Figure 8 shows the estimated potential developable land area suitable for solar plants in the SPP footprint could support 4,700 GW of solar generation even in the most limited land-use restrictions case. Under the same land-use restrictions, SPP would have land suitable for 1,200 GW of wind generation.

7 Solar Resource Data, Tools, and Maps | Geospatial Data Science | NREL at https://www.nrel.gov/gis/solar and Wind Resource Data, Tools, and Maps | Geospatial Data Science | NREL at https://www.nrel.gov/gis/wind

8 The Nature Conservancy, Power of Place: National Technical Briefing at https://www.nature.org/content/dam/tnc/nature/en/documents/TNC_Power_of_Place_National_Technical_Briefing.pdf

FIGURE 8: SPP WIND SOLAR GENERATION POTENTIAL (MOST RESTRICTED LAND-USE)




From a land-use perspective, the available land shown in Figure 8 easily supports the 20–48 GW of new wind and 42–130 GW of new solar generation investments that the FERNS study projects for the SPP region under the different load growth and renewable share scenarios. Appendix 3 presents additional details on the land-use study methodology and results. The land-use analysis can be refined to evaluate location-specific generation development opportunities for future transmission planning efforts within SPP's Consolidated Planning Process.

**KEY TAKEAWAYS**

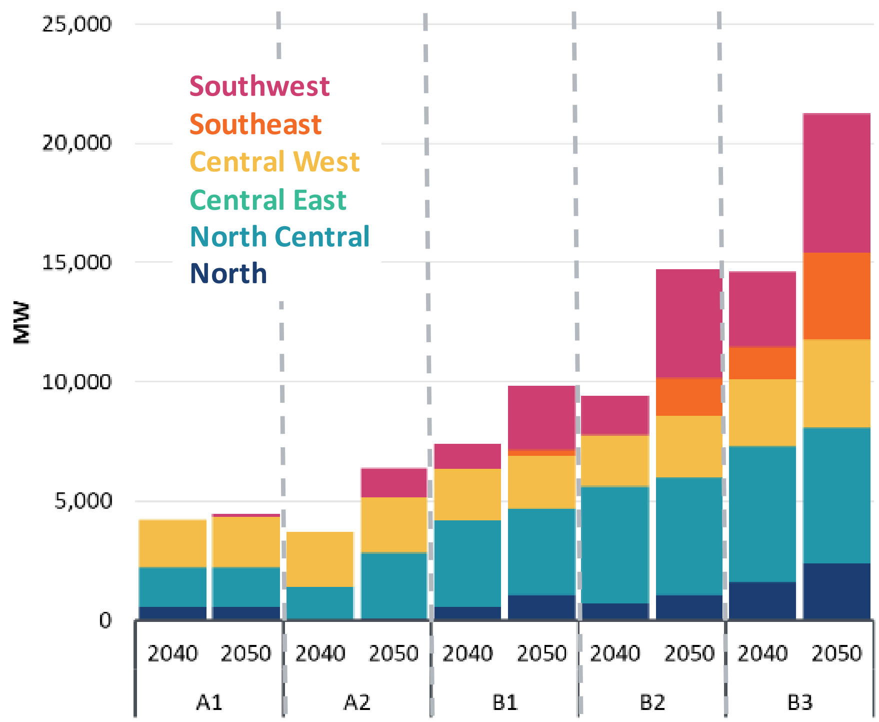
**Even when considering fairly stringent land-use restrictions, SPP has sufficient land to accommodate the 60–180 GW of new renewable resources across all FERNS scenarios. More detailed siting and nodal modeling will be needed to identify optimal generation locations near the existing grid and for new transmission investments.**

## C. Transmission

FERNS capacity expansion modeling optimizes the trade-off between developing new renewable generation near load centers in SPP's eastern zones and expanding interzonal transmission to increase transfer capabilities so more of the lower-cost generation can be developed in SPP's western and northern zones.[9] The simulation results show that interzonal transmission expansion within the SPP footprint is cost effective in all FERNS scenarios. Significantly more transmission capacity is built in high carbon-free generation futures (Scenarios B1, B2, and B3), with the highest optimal transmission expansion in the high electrification (demand-growth) scenarios, particularly Scenario B3.

As shown in Figure 9, the optimal levels of interzonal transmission expansions range from a low of 4,400 MW by 2040 to a high of 21,200 MW by 2050. A portion of these FERNS optimal transfer capability expansion results will be addressed by SPP's recently approved $7.7 billion portfolio of 2024 ITP transmission projects[10] (with the expansion amounts not yet available for the FERNS effort).

**FIGURE 9: TOTAL SPP *I*NTERZONAL TRANSMISSION EXPANSIONS ACROSS FERNS SCENARIOS**
*(MW OF ADDED ZONAL IMPORT/EXPORT* CAPABILITY *BY 2040 AND 2050)*




[9] As noted earlier and documented in Appendix 1, the existing SPP import/export limits of the six LOLE zones are consistent with the limits assumed in SPP's LOLE Study (which we understand have not been made publicly available). FERNS simulations do not allow for economic expansion of interfaces connecting SPP zones and external neighbors.

[10] Meghan Sever, SPP board approves $7.7 billion plan for transmission builds, upgrades, Southwest Power Pool, October 29. 2024 at https://www.spp.org/news-list/spp-board-approves-77-billion-plan-for-transmission-builds-upgrades/

As also shown in Figure 9, the most significant expansions occur to increase the import/export capabilities of SPP's north central and central west zones in the 70% moderate carbon-free generation share futures (Scenarios A1 and A2), while the most significant transmission expansions increase the import/export capabilities of the north central, southwest, and central west zones in the 90% carbon-free generation share futures (Scenarios B1, B2, and B3). Expansion of the Southeast import/export limit occurs mostly in the high renewable, high load growth futures (particularly Scenario B3).

Expansion of the North Central import/export limit is shown to be optimal in the 2030s to support new wind generation because the zone has relatively low export capability today. The central west zone offers high-quality solar and wind resources, which makes it an advantageous location to site renewables and increase the zone's transfer capability to send energy to serve load in eastern SPP.

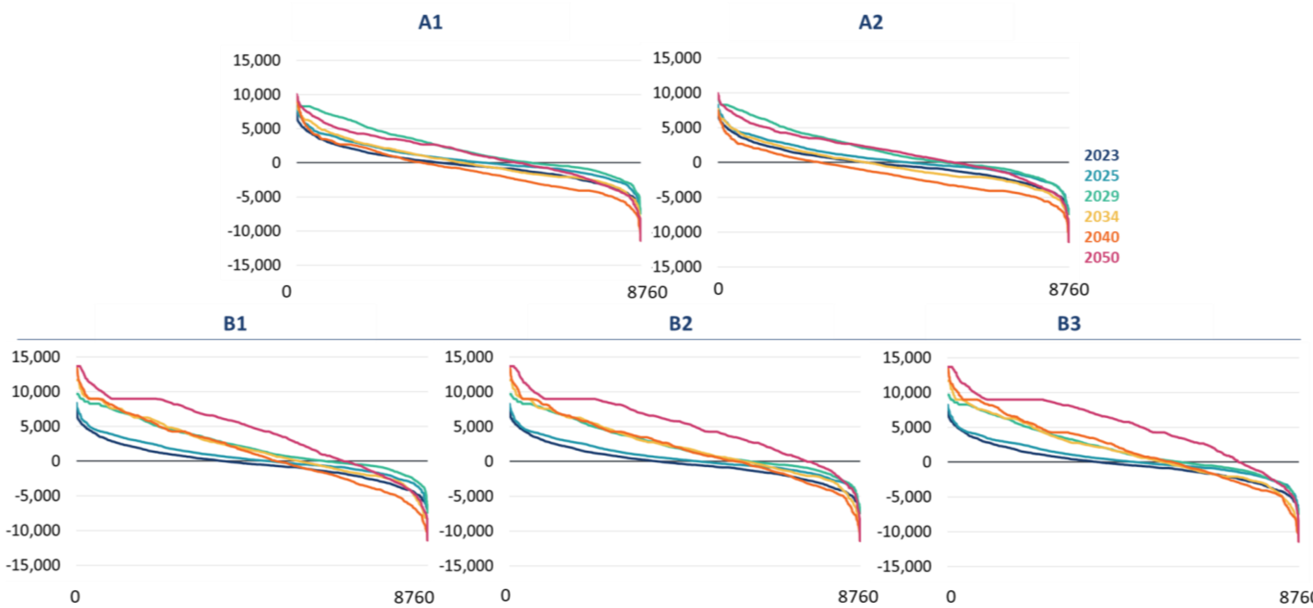
The quantity of optimal transmission capacity additions is sensitive to the assumed costs of transmission infrastructure upgrades relative to the costs of generation and local interconnection. At higher transmission costs (e.g., due to more expensive projects that would be needed to add transfer capability), less transmission expansion and more generation development near load centers would be optimal. The opposite would be the case if lower-cost opportunities exist to expand transfer capabilities (e.g., by means of grid enhancing technologies or the upsizing of existing lines).

### KEY TAKEAWAYS

**Between 4 and 21 GW of transmission expansion between the six SPP FERNS zones is projected to be cost effective and needed to support deliverability of renewables to load centers by 2050. This result is sensitive to the assumed transmission expansion costs (relative to the incremental cost of building more local generation) and includes expansions that will be provided by the recently-approved 2024 ITP transmission projects.**

SPP utilizes its transfer capability with neighboring regions to import and export power. The magnitude of these trades is projected to increase through 2050, particularly in FERNS scenarios B1, B2, and B3. While imports of (non-firm) energy from neighboring power markets are not counted to contribute to SPP's resource adequacy requirements, FERNS modeling captures cost effective trades between SPP and neighboring regions. The simulations project that SPP exports and imports remain almost balanced through the late 2020s in all FERNS scenarios, importing from external zones in slightly less than half of the hours of the year and exporting in the remaining half of the hours as shown in the "flow duration" curves of Figure 10—showing hourly exports between SPP and neighboring regions sorted from highest exports to highest imports.

**FIGURE 10: SPP NET IMPORTS AND EXPORTS WITH NEIGHBORING REGIONS (MW)**
*(POSITIVE = NET FLOW OUT OF SPP; NEGATIVE = NET FLOW INTO SPP)*[11]




In the high-renewable shares scenarios (with significant SPP wind and solar development due to a continuation of available tax credits or equivalent state or corporate renewable generation support), SPP's exports grow significantly as shown in the charts for Scenarios B1, B2, and B3. By the 2034 model year, SPP exports during approximately 75% of all hours; by 2050 exports occur during approximately 90% of all hours. Figure 10 also shows that, even as a significant net exporter, SPP will continue to import from neighboring regions up to approximately 10,000 MW of energy during hours when it is cost effective to do so—such as during SPP scarcity conditions when neighboring regions have available generation due to the geographic diversity in hourly load and generation.

[11] Net imports shown across interfaces between SPP and all neighboring regions

**KEY TAKEAWAYS**

**SPP will remain a modest net exporter during the 2020s but is projected to become a significant net exporter by 2050 due to a surplus of high-quality renewables in the "B" Scenarios. While interties are not counted toward meeting SPP's resource adequacy requirements, non-firm energy imports from neighboring regions are generally available during SPP scarcity conditions.**

# D. Resource Adequacy

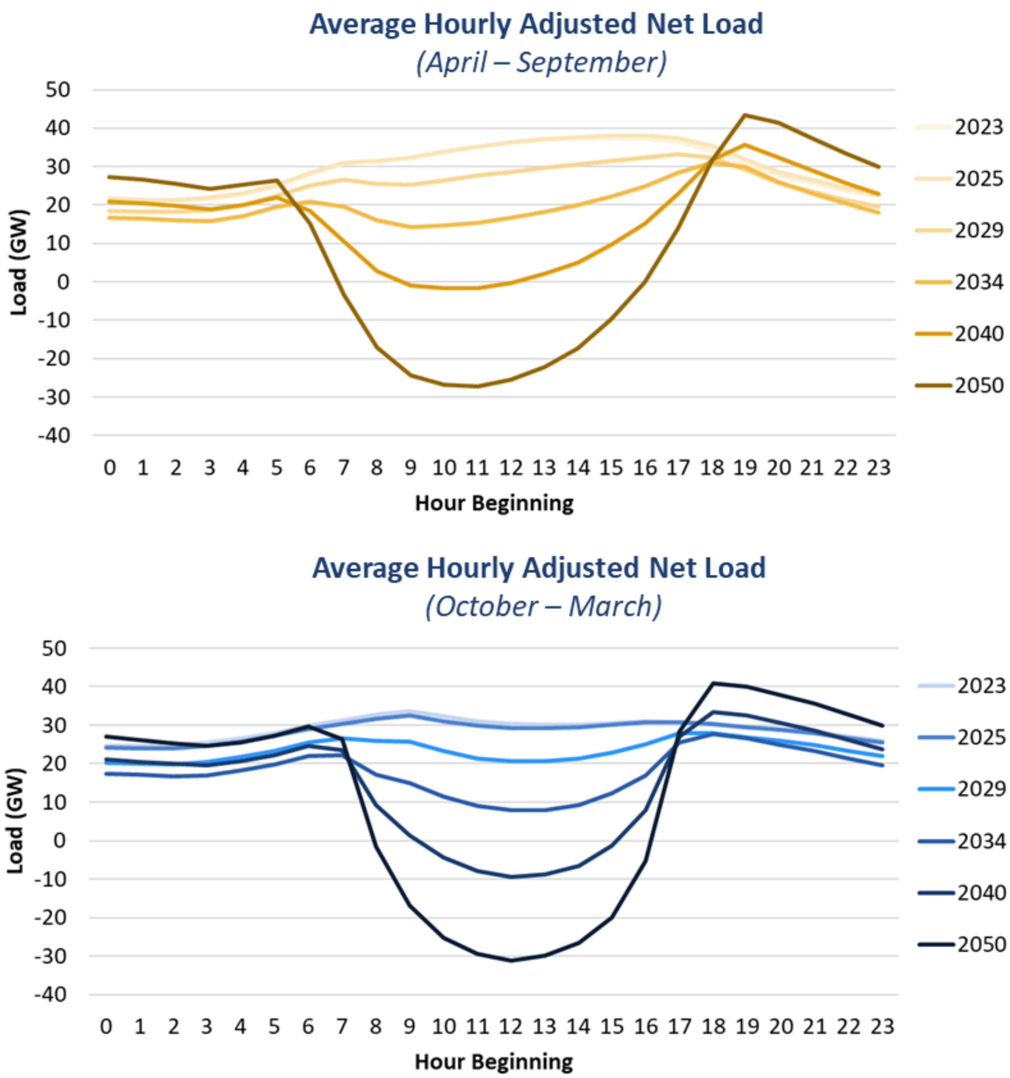
Across all FERNS scenarios, resource adequacy and reliability are maintained through an hourly 5% operating reserve margin requirement during all system conditions, including the challenging weather and resource adequacy conditions captured in the WRAS proxy year. Only SPP-internal resources (i.e., no firm or non-firm generation imported over interties from neighboring regions) are allowed to meet SPP resource adequacy needs in the FERNS simulations.

## 1. Evolving Resource Adequacy Needs

The simulations show that nature of SPP's resource adequacy challenges will evolve significantly over the next decades as the SPP region's demand grows and its generation mix changes significantly through 2050—the extent of which varies across the five FERNS scenarios. For the moderate electrification and high carbon-free resource future (Scenario B2), Figure 11 illustrates how SPP's "adjusted net load" changes through 2050 for the two (6-month) summer and winter seasons.

The adjusted net load metric (equal to hourly gross load less renewable generation and adjusted for fossil generation outages) illustrate how SPP's resource adequacy challenges shift over the years. Through the next decade, net peak hours remain concentrated in the early afternoon and the net load shape is relatively flat throughout the day, in both seasons. Starting in the 2030's, additional renewable resources (primarily solar) begin to shift the net peak hours into the early evening, with resource adequacy challenges shifting from peak load hours in the afternoon to the early evening after the sun sets. These new net load peaks shown in Figure 11 will need to be addressed through dispatchable resources and storage resources (which can be charged during the day, when solar generation is high and net load is low or negative).[12]

**FIGURE 11: SPP'S AVERAGE HOURLY "ADJUSTED NET LOAD" FOR SUMMER AND WINTER DAYS[13]**




12 Note that load management programs were not explored within the FERNS scope, but will additionally be available to meet future resource adequacy needs. For example, see Hledik et al., "New York's Grid Flexibility Potential," prepared for NYSERDA and NY DPS, January 2025. https://www.brattle.com/insights-events/publications/brattle-experts-conduct-a-study-to-determine-new-yorks-grid-flexibility-potential-in-2030-and-2040/

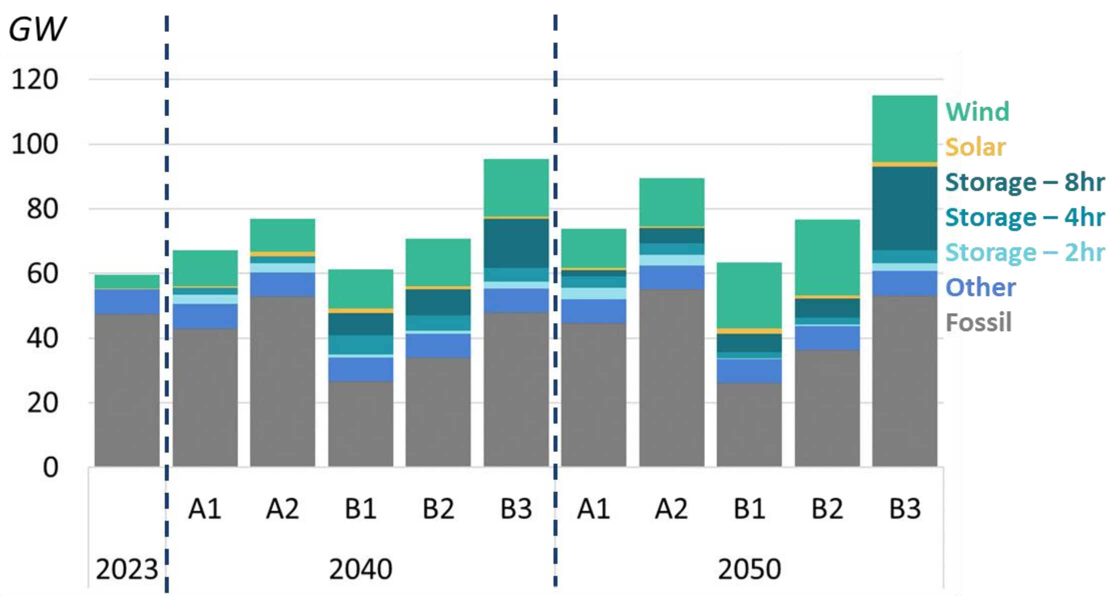
13 Charts show the average 24-hour seasonal shape of system gross load minus variable renewable generation (solar, wind) plus temperature drive fossil outages for the B2 scenario with medium electrification assumptions and high carbon-free resource share reaching ~90% by 2050. Net load does not reflect any storage dispatch.

SPP is already experiencing winter resource adequacy challenges, as demonstrated by the severe winter cold snaps in 2021 and 2022. Such weather-related challenges may increase over time as more weather-dependent generating resources are added to the SPP footprint.

We document how SPP's resource adequacy challenges and capacity needs shift over time by examining the top 100 hours with the highest resource adequacy risks, which are the 100 hours with the highest adjusted net load (adjusted for thermal outages). These top 100 hours are the most challenging times when SPP will need to rely on all generation resources available during these hours, including peaking plants.

Figure 12 shows available generation capacity during these 100 hours with the highest resource adequacy risks for 2023, 2040, and 2050 across the five FERNS scenarios. As shown, fossil resources remain crucial to maintaining resource adequacy during the highest RA-risk hours throughout the entire 2023–2050 study period, despite the fact that annual energy generation from these fossil resource declines to 10% to 30% of total energy output across all FERNS scenarios.

FIGURE 12: SPP AVAILABLE CAPACITY DURING 100 HIGHEST RA-RISK HOURS (GW)




Even in 2050, SPP is projected to rely on fossil resources for 41%–62% of the available capacity during the top 100 RA risk hours in the FERNS scenarios. Solar plays a limited role in serving resource adequacy needs, despite its high share of installed capacity and annual energy production—mostly because hours with high resource adequacy risk occur during evening hours (after sunset) starting by the mid 2030s as previously shown in Figure 11.

Figure 13 and Figure 14 summarize for Scenario B2, the top 100 most resource adequacy challenged hours in each simulation year for by month and by hour of the day. Figure 13 shows that the number of most challenging hours shifts from summer months (July and August) to winter months (December through February). In fact, by the mid 2030s, the majority of the most resource-adequacy-challenged hours will occur during winter months. Figure 14 similarly shows that most of these resource-adequacy-challenged hours will have shifted from the early afternoon into the early and late evening hours. By 2040, early morning hours also start creating resource adequacy challenges. Additional detail on how these summer and winter resource adequacy challenges shift over time and under different FERNS scenarios are presented in Appendix 2.

**FIGURE 13: TOP 100 RESOURCE ADEQUACY RISK HOURS BY MONTH (SCENARIO B2)**

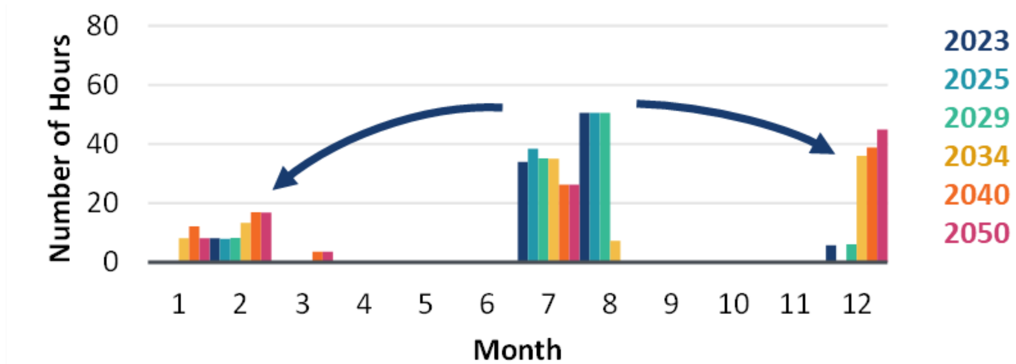
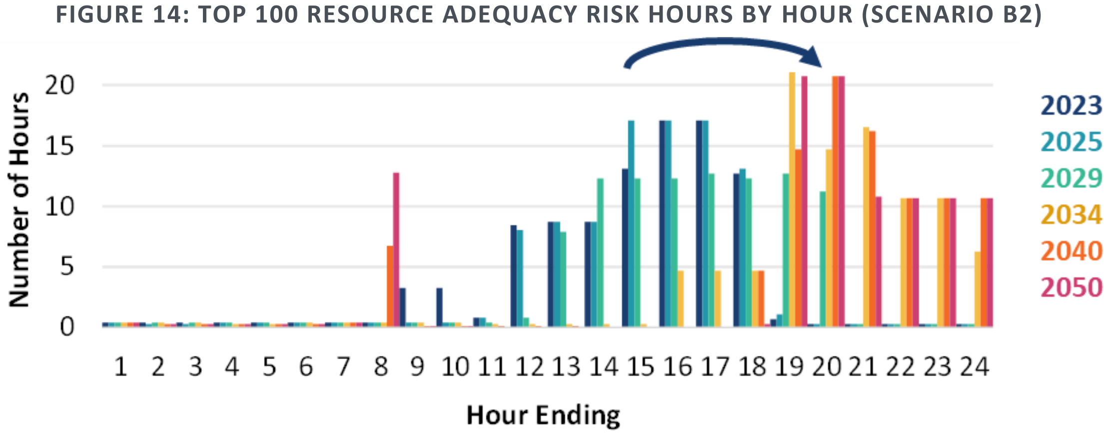



**FIGURE 14: TOP 100 RESOURCE ADEQUACY RISK HOURS BY HOUR (SCENARIO B2)**




Note, however, that the above figures showing the top 100 most resource constrained hours do not quantify the actual resource adequacy risk in each year at the level of precision that probabilistic resource adequacy study (and associated loss of load expectation or unserved energy metrics would). Nevertheless, the figures illustrate how resource adequacy needs evolve over time as SPP resource mix changes and demand grows.

From a loss of load probability perspective, the simulations show that the optimal generation mix is able to serve loads plus a 5% contingency reserve during all hours in all scenarios, with the exception of the winter-storm periods. During the simulated 3-day cold snaps, which are expected to occur every 5–10 years, resource adequacy violations of up to 8,900 MW occur in some of the scenarios and model years. However, other than in 2023 (as shown in Slide 23 of Appendix 2), these resource adequacy violations are not associated with load shed events due to (non-firm) energy imports available from neighboring regions (which do not experience the most severe impacts of the winter storm at exactly the same time).

**KEY TAKEAWAYS**

**SPP will be able to meet resource adequacy standards even in a highly electrified system with 70–90% carbon-free generation. However, resource adequacy risk challenges evolve over time to be more frequent during: (a) winter months (particularly in high demand-growth futures) and (b), starting after significant solar generation has been developed by the mid 2030s, the early evening hours (after the sun sets). Conventional generation continues to meet a disproportional share of SPP's resource adequacy requirements throughout the study period, projected to account for 41–62% of the capacity available during resource adequacy challenges in 2050.**

## 2. The Capacity (ELCC) Value of Resources

The FERNS generation expansion modeling approach does not need to rely on ELCC and planning reserve margin assumptions.[14] Instead, the resource adequacy value of each resource type is determined endogenously through hourly resource adequacy requirements. This is possible because the hourly approach to resource adequacy captures the impact of variation in weather conditions, renewable quality, load conditions, and resource mix on the capacity value of resources. This allows us to calculate "proxy ELCC values" for different resource types (i.e., wind, solar, storage, and fossil generation) from FERNS simulation results to suggest how the capacity value of different resource types is projected to change over time under evolving system conditions.

[14] As explained earlier, FERNS deploys an hourly resource adequacy constraint that ensures adequate hourly available capacity (based on renewable generation profiles, thermal resources not on forced temperature driven outage, and storage with sufficient capacity and energy to discharge) can serve load plus a 5% operating reserve cushion in all zones and SPP wide.

To report results for the effective load carrying capability of different resource types, we calculate these proxy ELCC values based on the generating capacity available during the top 100 most resource-adequacy challenged hours as reported in Figure 13 and Figure 14. By focusing on available generation during the most challenging hours of the year, these proxy ELCC results approximately reflect the resources' marginal ELCC value. The estimated proxy ELCC values of wind and solar generation are shown in Figure 15 for Scenario B2. As the figure shows, the summer ELCC value is projected to decline from 40% in the 2020s to almost zero by 2040. In contrast, the proxy ELCC values of wind plants increase over time as resource-adequacy-challenged hours shift to periods with higher wind generation.

**FIGURE 15: PROXY SEASONAL ELCC VALUES FOR WIND AND SOLAR RESOURCES (SCENARIO B2)**

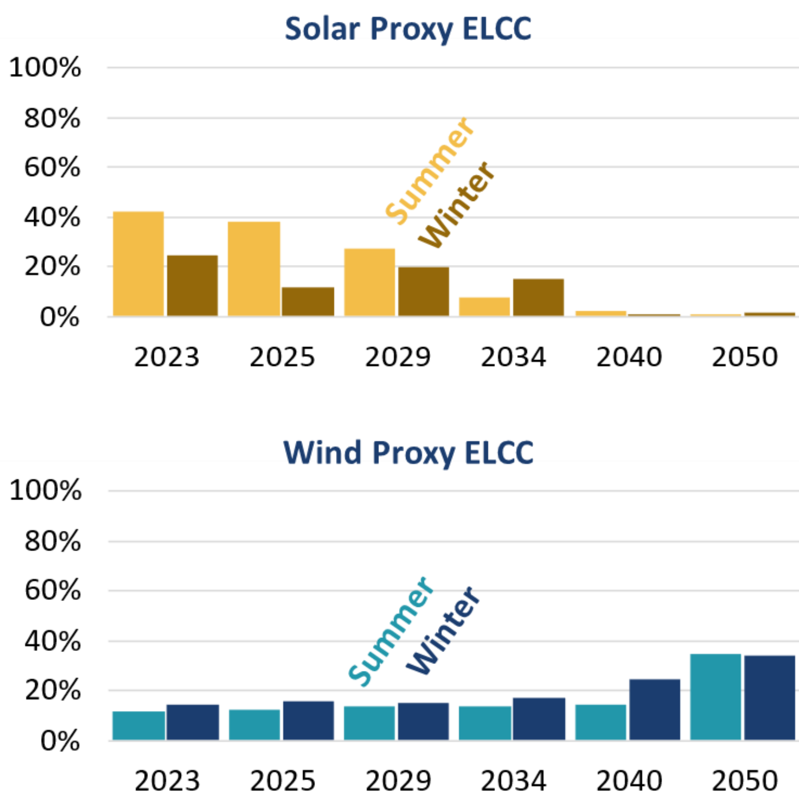
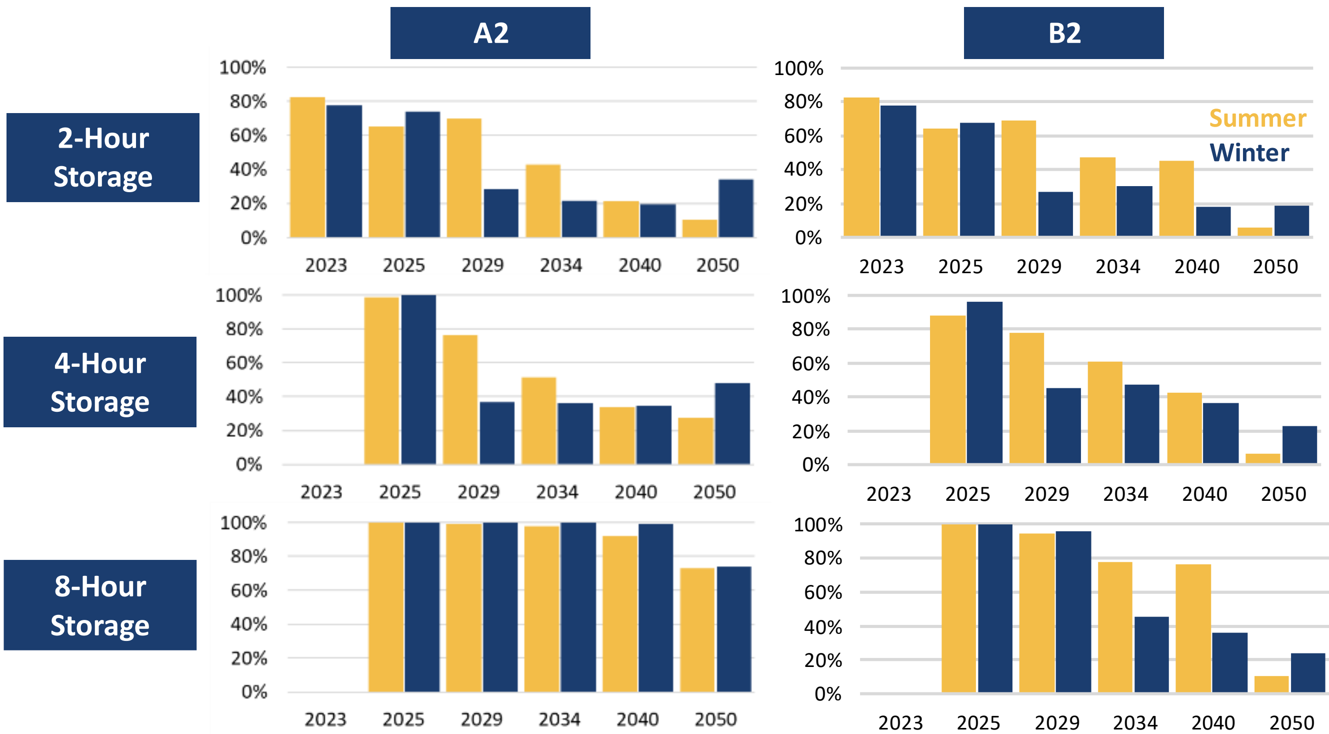



Figure 16 below shows proxy ELCC values for storage resources for Scenarios A2 and B2. The charts show that storage ELCC values are high initially but decrease quickly for 2-hour and 4-hour storage facilities as resource adequacy challenges shift into the early and late evening hours—a time when resource adequacy risks require long-duration storage. The proxy ELCC values of 8-hour duration storage remains high in the moderate renewable energy "A" scenarios but decline significantly in the high renewable energy "B" scenarios as illustrated for A2 and B2 below and summarized in Slide 29 of Appendix 2. These results suggest that, when pushing beyond 70% and towards 90% renewable generation, the system will have a strong need for long-duration storage, as implied by the significant decline in the proxy ELCC values of 8-hour storage resources. (FERNS modeling did not include battery storage with durations greater than 8 hours.)

**FIGURE 16: PROXY SEASONAL STORAGE ELCC VALUES (MARGINAL) BASED ON TOP 100 RESOURCE ADEQUACY HOURS**




We also report proxy ELCC values for fossil generating resources, reflecting high weather correlated outages during cold snap events. Based on the simulated performance of fossil generators (shown for Scenario B2 in Slide 28 of Appendix 2), their proxy ELCC value is 70% initially (increasing to 80% by the mid 2030s) during the winter season and approximately 90% during the summer across all model years.

Finally, we note that FERNS simulation results show that non-firm energy imports over the interties with neighboring regions offer significant reliability and extreme-weather resilience value. While these imports of resources available in neighboring regions during SPP's resource-adequacy challenged hours are not counted towards SPP's resource adequacy requirements in the FERNS simulations, the imports provide significant resource adequacy and (as Slide 24 of Appendix 2 indicates) extreme-cold-weather resilience value to the SPP footprint. Slide 32 in Appendix 2 shows (for Scenario B2) that the ELCC-equivalent value of many of SPP's interties with neighboring averages is approximately 40% of the intertie capacity—declining to an average of approximately 30% in the 2030s and 2040s. However, since FERNS includes only a simplified representation of neighboring zones, more detailed analyses would be needed to confirm the resource adequacy value of SPP's uncommitted interties with neighboring regions.

**KEY TAKEAWAYS**

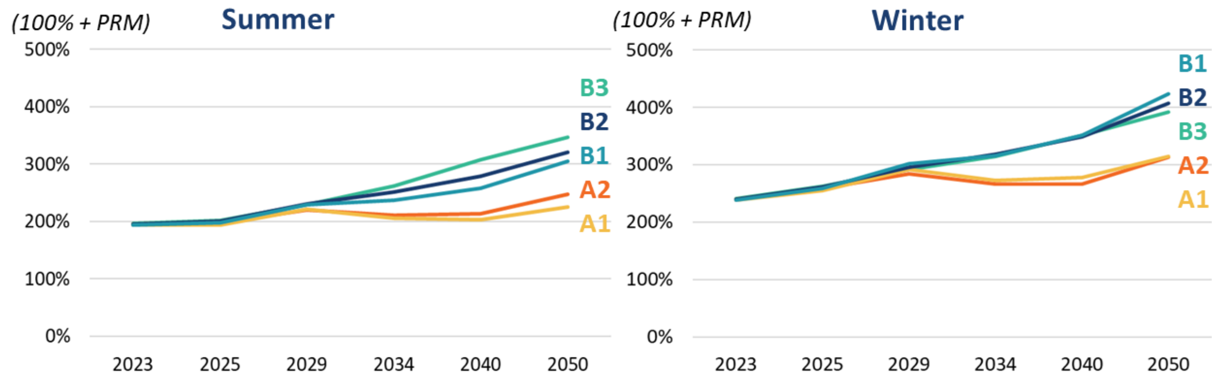
**ELCC values of wind, solar, and storage resources are projected to change significantly over the next decades. The proxy ELCC values of solar and 4-hour storage resources are projected to decline quickly in the 2030s, while that of wind resource increases slightly over time. The proxy ELCC value of 8-hour storage remains high in the moderate renewable energy scenarios, but declines significantly in the high renewable energy scenarios, indicating the need for longer-duration storage. The simulations also show that: (a) the ELCC value of fossil resources is between 70% and 90% of their installed capacity and (b) SPP benefits from significant resource adequacy and extreme weather resilience value provided by its interties with neighboring regions.**

## 3. SPP Planning Reserve Margins

To further illustrate how resource adequacy challenges evolve over time and across different scenarios, we also calculated seasonal planning reserve margins (PRM)—both in terms of installed capacity (ICAP) and in terms of unforced capacity (UCAP), using the proxy ELCC values shown above.

Figure 17 shows the seasonal ICAP reserve margins implied by the resource-adequate generation mix for each of the five FERNS scenarios. It shows that SPP's ICAP reserve margin is approximately 100% today (with installed capacity approximately 200% of seasonal, weather-normalized peak loads). As more wind and solar resources are added to the system, these installed capacity values increase to 300–400% of weather-normalized peak loads.

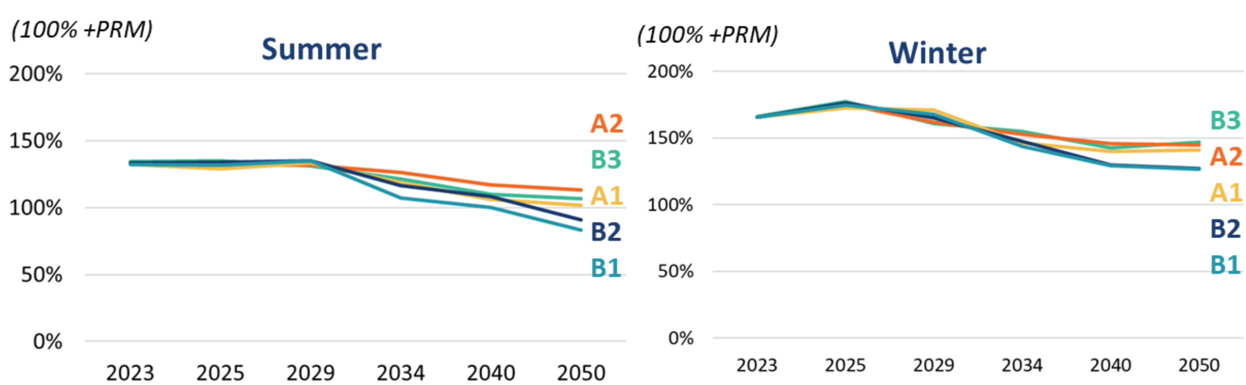
FIGURE 17: SPP IMPLIED SEASONAL ICAP PLANNING RESERVE MARGINS




In installed capacity terms, these seasonal planning reserve margins are highest for the high renewable generation share Scenarios (B1, B2, and B3), which are all greater than three times the seasonal peak load by 2050. Figure 17 also shows that higher electrification load growth scenarios (A2, B2, and B3) require more installed capacity to maintain a resource adequate system relative to peak load than the low load growth scenarios (A1 and B1).

Figure 18 shows seasonal UCAP planning reserve margin based on the credited capacity from estimated seasonal proxy ELCCs for wind, solar, and storage resources (but using ICAP for fossil plants, consistent with current SPP practice).

FIGURE 18: SPP IMPLIED UCAP RESERVE MARGIN (BASED ON FERNS PROXY ELCC)




As the charts in Figure 18 show, these UCAP PRMs are more constant over time at approximately 40% (of weather-normalized summer peak load) during the summer season and approximately 60% (of weather-normalized winter peak load) during the winter season. However, starting in the 2030s, the UCAP-based PRMs start to decline—in some cases below 100% of seasonal weather-normalized peak loads—as resource-adequacy-challenged hours shift into the early evenings, when loads are below their daily peaks.

The perhaps counter-intuitive trends shown in Figure 17 and Figure 18 illustrate that ICAP and UCAP planning reserve margin (as a percentage of seasonal weather-normalized peak load) may become less useful as the sole resource adequacy metric starting in the 2030s, when resource adequacy challenges shift away from peak load hours. At that point, for example, expressing PRMs as a function of load during the most resource-adequacy-challenged hours of the year or season, may be a more accurate metric.

**KEY TAKEAWAYS**

**Planning reserve margins (in ICAP terms) increase significantly over time as more resources with low ELCC values are added to the SPP grid.**

**In UCAP terms (using FERNS proxy ELCCs), planning reserve margins are approximately 40% during the summer and approximately 60% during the winter through the mid 2030s, before declining as resource adequacy challenged hours shift into the evening.**

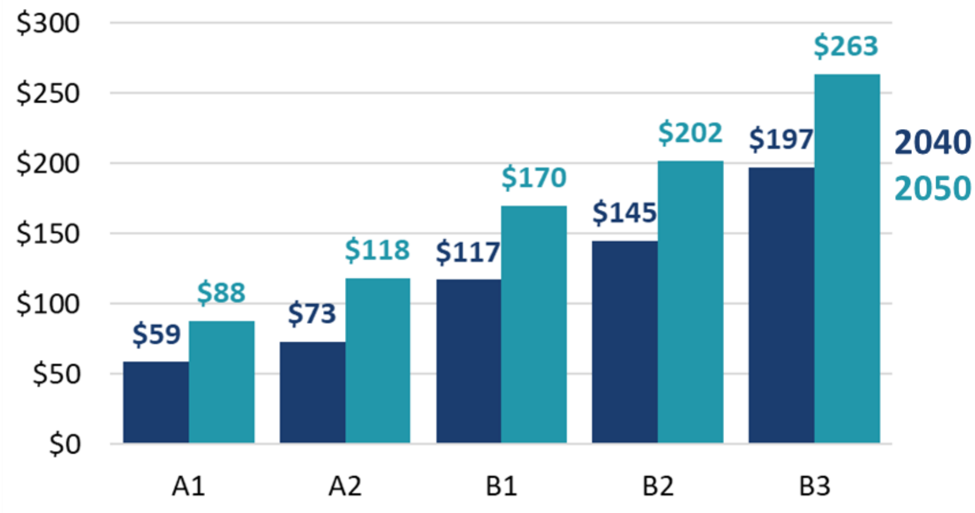
**Starting in the 2030s, planning reserve margins as a function of weather-normalized peak load likely will no longer be a sufficiently comprehensive resource adequacy metric, as resource adequacy risks are projected to shift from peak load hours into in lower-load evening hours.**

## E. System Costs

The total generation and transmission investment and operating costs necessary to serve loads and maintain resource adequacy varies greatly across the five FERNS scenarios based on the magnitude and composition of generation and transmission investments. As shown in Figure 19 below, between \$88 billion and \$263 billion of additional generation investments will be needed through 2050 in the SPP footprint.

The total generation investment is highest in high-demand and high renewable generation scenarios, primarily due to the large amount of capacity needed to maintain resources adequacy in a high-electrification, high load-growth future. In the high renewable generation future (reflecting available tax credits or equivalent state or corporate renewable generation support), additional investments in solar, mid-duration storage, and wind generation assets are cost effective across the SPP footprint.

**FIGURE 19: TOTAL SPP GENERATION INVESTMENT NEEDS (2023–2050)**[15]
($billion, in inflation-adjusted 2023 dollar)

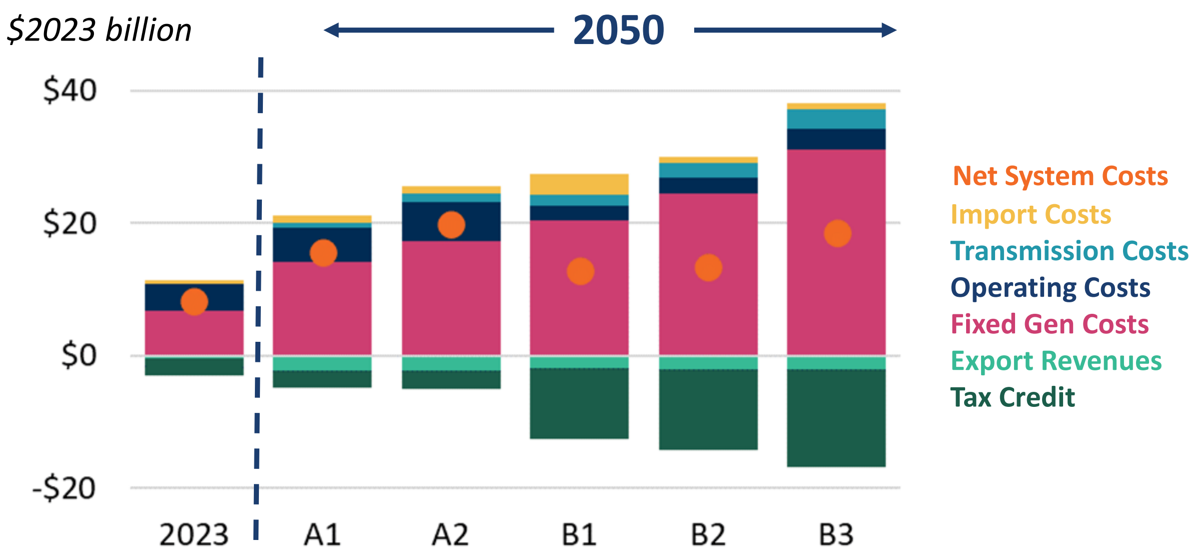



Driven by significant load growth and associated capital investments between today and 2050, the annual system-wide generation and transmission costs increase from 2023 levels by between 50% and 140% (to nearly $40 billion in Scenario B3) as shown in Figure 20 below. This annual cost metric include annualized investment costs for new generation and transmission investment, the annual fixed and variable operating costs of all installed generation, and the cost of imports from neighboring regions, net of export revenues and tax credits.

The annual costs shown do not include any distribution costs, nor the investment cost recovery of already-existing generation and transmission assets. More detailed cost results are presented in Appendix 2.

[15] Costs are in $2023 dollars. Includes only incremental CAPEX based on net additions. Does not net out value of tax credits. Excludes all transmission costs including those associated with zonal generator interconnection.

FIGURE 20: SPP ANNUALIZED GENERATION AND TRANSMISSION COSTS (2023 AND 2050)
(inflation adjusted, in $2023 billion/year)[16]

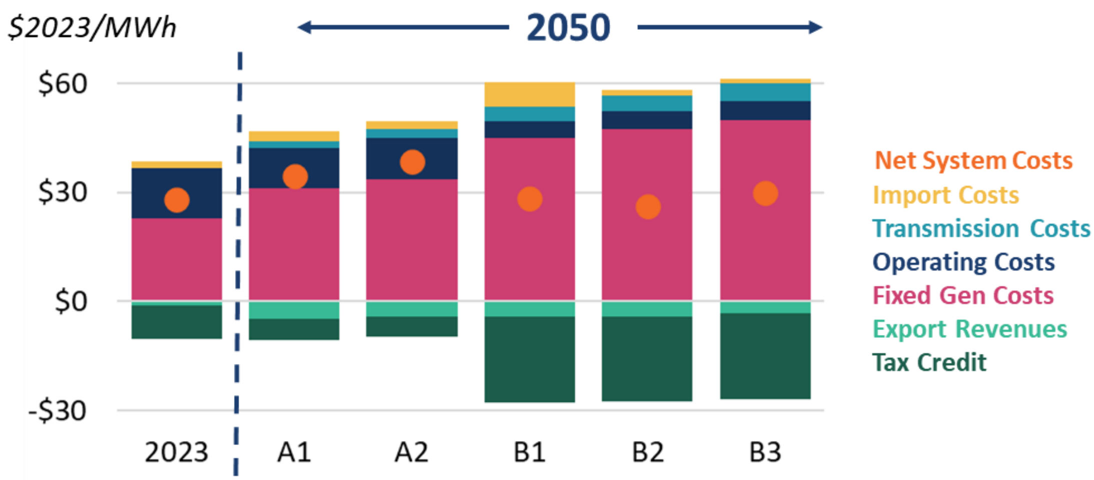



Fixed generation-related costs are the primary source of cost increases as all scenarios need additional generation investment to serve loads and maintain resource adequacy. The relative share of annual operating costs to other system costs declines over time, particularly in the scenarios with high renewable generation, as SPP increasingly relies on low variable cost renewable resources to reduce fuel costs for conventional generation. The assumed extension of federal tax credits in high renewable generation scenarios (B1, B2, and B3) offsets much of the capital cost increase.

Due to high load growth and tax credits (if available), the large increases in SPP system-wide costs do not translate into significant cost increases on a dollar per MWh basis. As shown in Figure 21, in 2023 inflation-adjusted $/MWh terms, costs remain relatively flat across all scenarios through 2050. While $/MWh costs increase slightly (i.e., by more than inflation) in Scenarios A1 and A2, the $/MWh cost will stay flat in real terms (i.e., at or slightly below inflation) through 2050 in Scenarios B1, B2, and B3 where tax credits are assumed to remain available (or are reinstituted).

[16] Annual costs are reported in inflation adjusted terms (in 2023 dollars). Investment costs are annualized over the life of the assets. Fixed costs recovery of existing generation and transmission is not included. Annualized cost categories consist of Fixed Gen costs (FOM, Annualized New Gen CAPEX Costs), Operating costs (Fuel Costs, VOM, Start Costs), Tax Credits (PTC, ITC), Import Costs (incl. Wheeling Costs), Export Revenues (incl. Wheeling Revenues), and Transmission Costs (new Interzonal Transmission Costs and Generator Interconnection Costs).

**FIGURE 21: SPP GENERATION AND TRANSMISSION COSTS IN $/MWH (2023 AND 2050)**
(inflation adjusted, in 2023 dollars)




The modest increases in $/MWh system costs suggest that—under the technology and fuel cost assumptions made in this study—SPP is projected to maintain resource adequacy in 70–90% renewable generation futures through 2050 with customer rate increases approximately in line with that of general inflation. A low-rate impact outcome is particularly likely if federal tax credits (or equivalent renewable generation support) for renewable generation and storage resources remains available.

## KEY TAKEAWAYS

**Between $88 and $263 billion in new generation investment will likely be needed to support SPPs energy transition and projected load growth through 2050. Due to load growth and avoided fuel costs, this is possible without large rate increases (beyond general inflation)—especially if tax credits (or other similar support) for renewable generation and storage resources remains available.**

# III. Conclusions

The Future Energy and Resource Needs Study (FERNS) demonstrates that Southwest Power Pool (SPP) is well-positioned to navigate an energy future shaped by high demand growth (electrification) and the growing deployment of wind and solar resources. Even without federal tax credits or similar support for renewable generation, SPP is projected to reach 70% carbon-free generation by 2050, driven by the cost-effectiveness of wind, solar, and storage technologies and the projected increase in natural gas prices. If current tax credits or comparable renewable support remain available, SPP is projected to reach 90% renewable generation, with solar emerging as the dominant resource after 2035, complementing wind generation. In combination with retaining conventional generation and substantial investments in cost-effective mid-duration storage resources, SPP is projected to be able to maintain resource adequacy for all five FERNS scenarios studied. Importantly, this is projected to be possible at only modest cost increases in $/MWh terms, roughly in line with general inflation trends (and only slightly higher without, if the currently-available tax credits are eliminated).

Still, transitioning to a high-load growth and high carbon-free generation grid will require significant investments in generation and transmission infrastructure. The FERNS simulation results project that between $88 and $263 billion in new generation investments will be needed to meet future system demands by 2050—although this likely can be accomplished without increasing customer rates beyond inflation trends, particularly if existing levels of federal policy support remains available. To ensure that renewables are developed and delivered cost effectively to load centers, the study identifies up to 21 GW of cost-effective interzonal transmission capacity expansion.

As SPP progresses toward a low-carbon and electrified future, maintaining reliability will remain paramount. Resource adequacy challenges are expected to evolve over time, particularly as significant amounts of solar generation are added to the SPP footprint in the 2030s and 2040s. Resource adequacy risk will become more frequent during winter months and shift from afternoon peak load periods into early evening hours—times when the system will continue to require dispatchable generation in addition to storage and renewable generation.

We hope the FERNS results allow SPP stakeholders to develop a deeper understanding of the opportunities and trade-offs involved as SPP plans for a changing energy landscape, ensuring a reliable and cost-effective grid for the decades ahead.  We also hope that the FERNS scenario result will help inform SPP's future transmission planning efforts.

# Appendix 1

# FERNS Modeling Methods and Assumptions

CONTENTS

# APPENDIX 1:

# FERNS Modeling Methods and Assumptions

# Analytical Approach

The Brattle team deployed **gridSIM**, our in-house capacity expansion model, to examine costs and resource adequacy (RA) risks in the future SPP system under five FERNS scenarios.

- **Optimization model** that minimizes system investment and operation costs, providing optimized power system build-out and dispatch for given scenario conditions
- **Co-optimized modeling** and pricing of energy and RA markets (with endogenous interzonal transmission optimization)
- **Zonal representation of SPP system**, transmission limits, and resource adequacy constraints mimic power systems and markets
- **Chronological commitment and dispatch** to model storage and generators; representative periods with hourly detail, including multiple days with challenging system conditions (heatwaves, cold snap, renewable drought, thermal outages)
- **Key outputs** consist of least-cost capacity expansion, retirement, and dispatch to meet demand for energy/capacity subject to transmission constraints, detailed system cost accounting, and resource adequacy metrics
- **Resource adequacy** modeled hourly for sampled proxy periods to closely represent 15 SPP-supplied weather years and cold snap periods

***Brattle "owning of the code"** enables great flexibility for tuning the model to specific aspects of the SPP market and geographic-specific challenges*

# gridSIM Inputs, Optimization and Constraints, and Outputs

## INPUTS

### Supply

- Existing resources
- Fuel prices
- Investment/fixed costs
- Variable costs

### Demand

- Representative periods (hourly chronology)
- Capacity needs

### Transmission

- Zonal limits and expansion costs
- Intertie limits

### Regulations, Policies, Market Design

- Resource adequacy modeling
- Clean energy policies and investment support

## gridSIM OPTIMIZATION ENGINE

### Objective Function

- Minimize NPV of investment & operational costs

### Constraints

- Market design and co-optimized operations
  - Capacity
  - Energy
- Regulatory & policy constraints
- Resource operational constraints
- Transmission constraints

## OUTPUTS

**Annual investments and retirements**

**Hourly operations**

**Annual transmission interface expansion**

**Clean energy additions**

**Resource adequacy risk assessment metrics**

# Summary of Modeling Inputs

| Data Element | Description and Source Notes (may differ by year modeled) |
|---|---|
| | **Transmission Modeling Inputs** |
| **Energy Zones** | Six SPP-internal energy zones consistent with 2023 LOLE Study zones (North, North Central, Central West, Central East, Southwest, and Southeast) |
| **Transmission Topology and Limits** | Interface limits between each internal zone and the rest of SPP consistent with 2023 LOLE study limits (ATC and FCITC); the simulations will optimally expand the internal transmission limits based on SPP transmission cost estimates |
| **Imports and Exports** | Fixed import and export limits with neighboring regions provided by SPP staff. Hourly energy transfers based on simplified modeling of external zones to capture regional variations in load, renewables (over the same 15 weather years and cold snaps) and associated diversity benefits |
| | **Demand-Side Modeling Inputs** |
| **Load Growth** | Low, moderate, and high scenarios developed by Evolved Energy Research (EER) for SPP FERNS Demand Electrification that represents a range of electrification scenarios and 15 weather years |
| **Hourly Load Shapes** | Hourly shapes developed by EER for SPP FERNS Demand Electrification that vary by weather year, SPP zone, end-use, and scenario for 2023, 2025, 2029, 2034, 2040, 2050 |

# Summary of Modeling Inputs

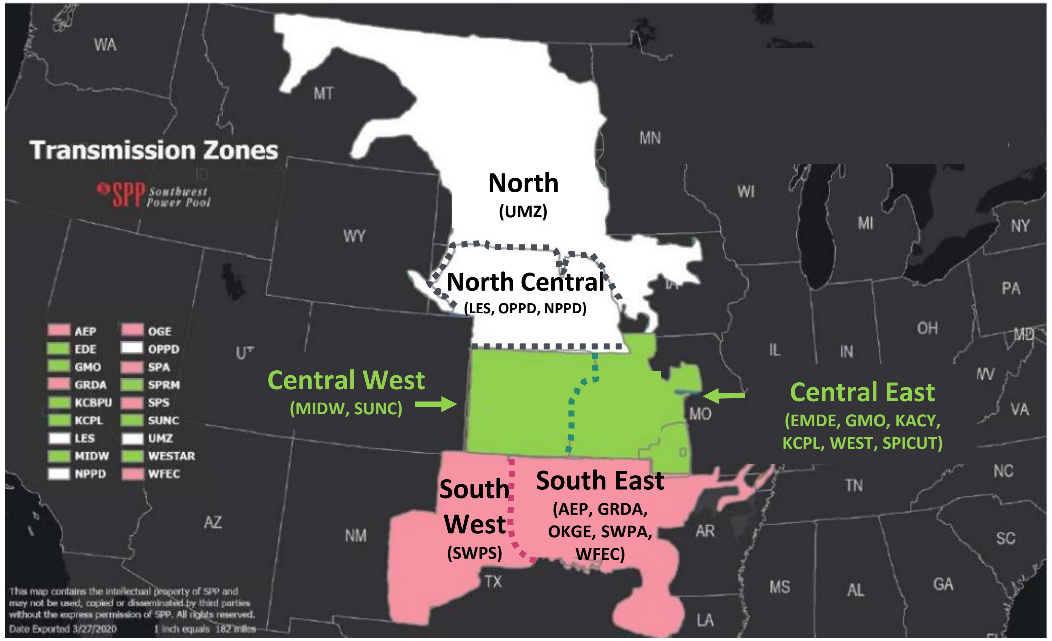
| Data Element | Description and Source Notes (may differ by year modeled) |
|---|---|
| **Supply-Side Modeling Inputs** | |
| **Existing Generator Data** | SPP data (2025 ITP) for existing unit capacities, heat rates, and additional operational characteristics by region |
| **Scheduled Additions/Retirements (near term)** | SPP data (2025 ITP) and Interconnection Queue studies to identify resource decisions already made (as model input) by capacity, location, date. (Necessary additional future generation additions and retirement decisions are optimized by the model) |
| **Cost Trajectory for New Generation** | Capital, fixed, and variable cost projections for new generators by resource type and SPP zone from SPP IHS forecasts; zonal costs and intra-zonal transmission adders as function of resource availability and transmission headroom/cost by zone informed by SPP interconnection studies |
| **Hourly Renewable Generation** | Hourly renewable profiles for all SPP zones and external regions, for all 15 weather years available in the load dataset, based on Imperial College London (Renewables.ninja) dataset and benchmarked to National Renewable Energy Laboratory (NREL) regional values |
| **Fuel Prices** | Natural gas, coal, and oil prices (by SPP zone) from SPP IHS forecasts and 2024 and 2025 ITP; additional fuel types supplemented from other public sources like the NREL. |
| **Market and Policy Inputs** | |
| **Reserve Margin and RA framework** | FERNS uses an hourly approach to determine resource adequacy needs (based on hourly loads, operating reserves, renewable profiles, and generation outages associated with 15 weather years and cold snaps). FERNS defines RA requirements as hourly load plus a 5% capacity (operating reserve) margin, which needs to be maintained across the full range of challenging system conditions (such as heat waves, cold snaps, renewable droughts, and high generation outages). A $50,000/MWh “resource adequacy violation charge” represents tradeoffs between adding generation capacity or allowing for load shedding (or operating reserve depletion) approximately once in ten years during the most challenging hours across all weather years. |
| **Tax Credits and Clean Energy Policies** | IRA-based PTC for solar and wind (and ITC for battery storage) or equivalent (state or corporate) support, assumed for the entire study horizon in Scenarios B1, B2, and B3. Assumed eliminated for Scenarios A1 and A2. No other clean energy policies are assumed for the SPP footprint. |

# Zonal Topology and Transmission Limits

The gridSIM topology represents the SPP footprint using a pipes-and-bubble approach, aggregating generators and loads into a multi-zonal energy model

- We model 6 zones in SPP, consistent with the 2023 Draft LOLE zones, aggregated up from transmission pricing zones
  - North, North Central, Central East, Central West, Southeast, Southwest
  - The southern and central zones are split between east and west to capture congestion and transmission needs between the renewable-rich load-rich portion of these zones
- Zones capture congestion, which requires the definition of interzonal transmission limits and expansion costs
  - SPP interzonal transmission limits from SPP 2023 LOLE study between each zone and the rest of SPP that define forward and reverse flow limits
  - We allow the model to economically expand transmission limits between zones (co-optimized with building resources within zones to achieve lowest total costs)

**Zones for FERNS Study**

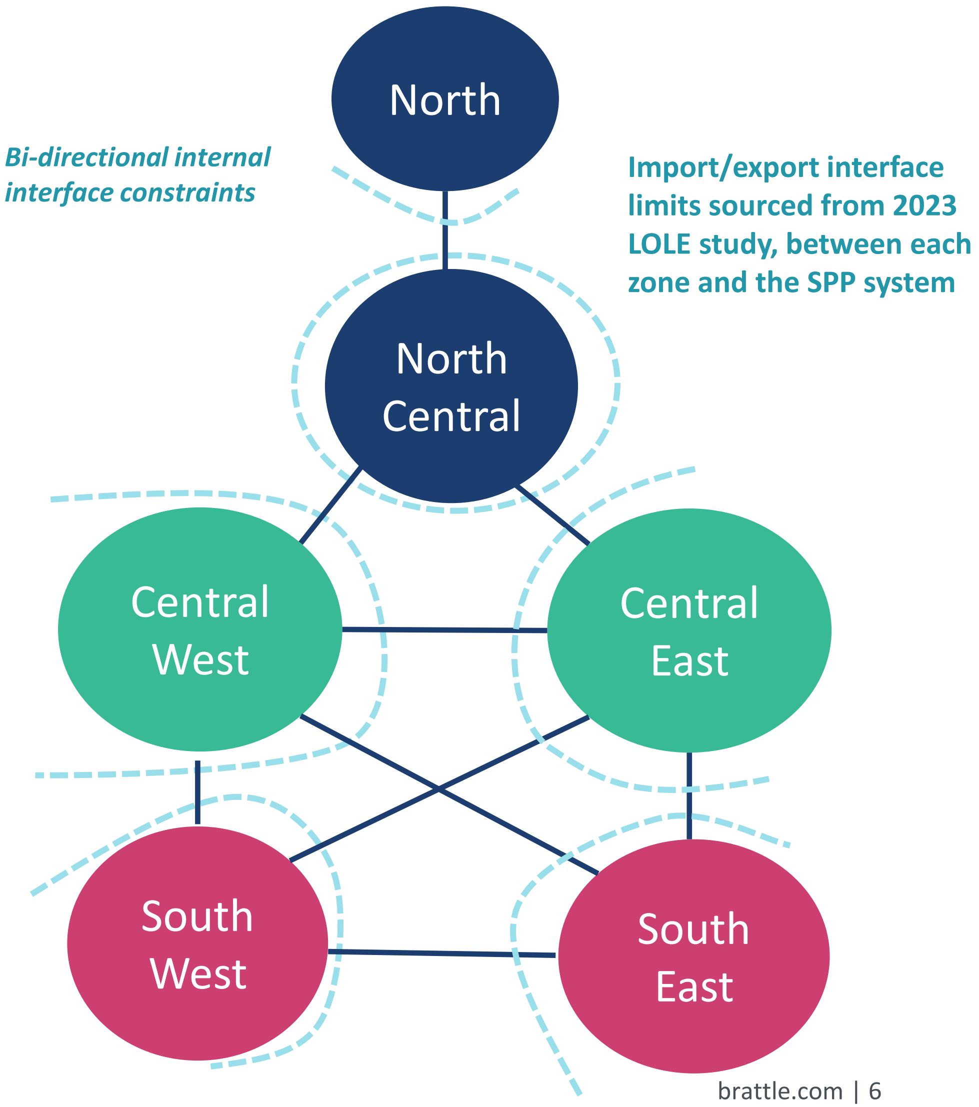



Base map source: SPP

# Zonal Loads, Generation, and Internal Transmission Limits

- SPP load data is from FERNS Demand Electrification Modeling scenarios for 15 weather years (2006-2020)
- Existing generator data (Integrated Transmission Planning 2025) is aggregated into the 6 zones shown at right
  - Include already-planned generation additions and retirements (e.g., through 2030) as model input with model-based economic decisions allowed in 2029
- Simultaneous transmission export and import limits constrain hourly energy flows between zones
  - Based on zonal export/import limits used in 2023 LOLE study
  - Interzonal transmission constraints can create congestion and zonal price differences in the model, showing needs for additional in-zone resources or expanded inter-zonal transmission capacity
- Internal zonal import and export limits can be expanded optimally based on proxy ($/MW) expansion costs
  - Expansion costs sourced from SPP transmission teams and public studies
- Renewable costs, generation profiles, and technical potential will vary by zone
  - Renewable profiles are weather consistent with 15 years of load data and vary by zone, to capture renewable drought variability in SPP footprint
  - Increasing zonal transmission/interconnection costs at higher renewable shares will be sourced from SPP generation interconnection studies and modeled as increasing transmission cost adders to renewable generation supply curves

**Modeled SPP Transmission Zones**



# External Zonal Topology

In addition to internal SPP zones, we model interties for 8 external zones with dynamic hourly transmission flows to/from SPP to capture economic and resilience benefit of interregional diversity

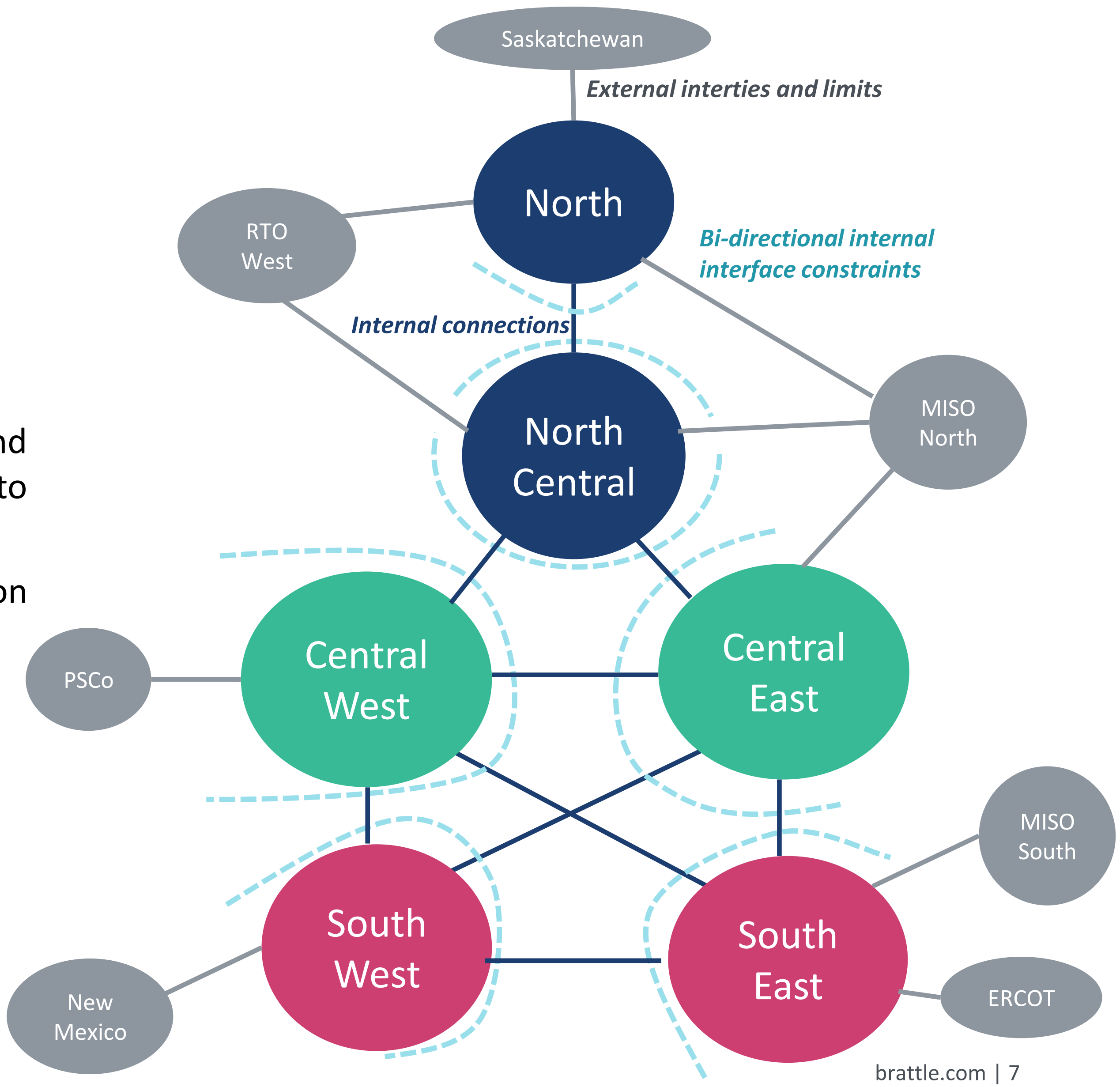
- Intertie limits were provided by SPP staff for import and export directions
- Each external zone is modeled with simplified aggregate load and resource mix, reflecting hourly differences in net-load variance to capture geographic diversity during the modeled weather years
- Future expansions of external resource capacity and transmission capabilities is an input assumption (i.e., not optimized by the model)

## Intertie Capacity (MW)

| MISO South | MISO North | RTO West |
|---|---|---|
| 2,486 (into SPP)<br>2,708 (out of SPP) | 2,165 (into SPP)<br>4,203 (out of SPP) | 2023-2034: 700<br>2034-2040: 1,400<br>2040 onwards: 2,400 |

| New Mexico | ERCOT | SASK | PSCo |
|---|---|---|---|
| 400 | 800 | 2023 - 2029: 150<br>2029 onwards: 650 | 210 |

## SPP Zones and Interties to Neighboring Systems



# External Zones: Hourly Demand and Generation Capacity

External zones capture diversity benefits between SPP and neighboring regions by modeling demand (for the same SPP-selected 15 weather years and cold snaps), generation, and dynamic hourly transfers with SPP. The generation expansion decisions for external zones are inputs to the model and not optimized. Capacity located outside the SPP footprint cannot contribute to resource adequacy requirements (similar to SPP's construct today), but the model optimizes hourly energy flows for trade benefits.

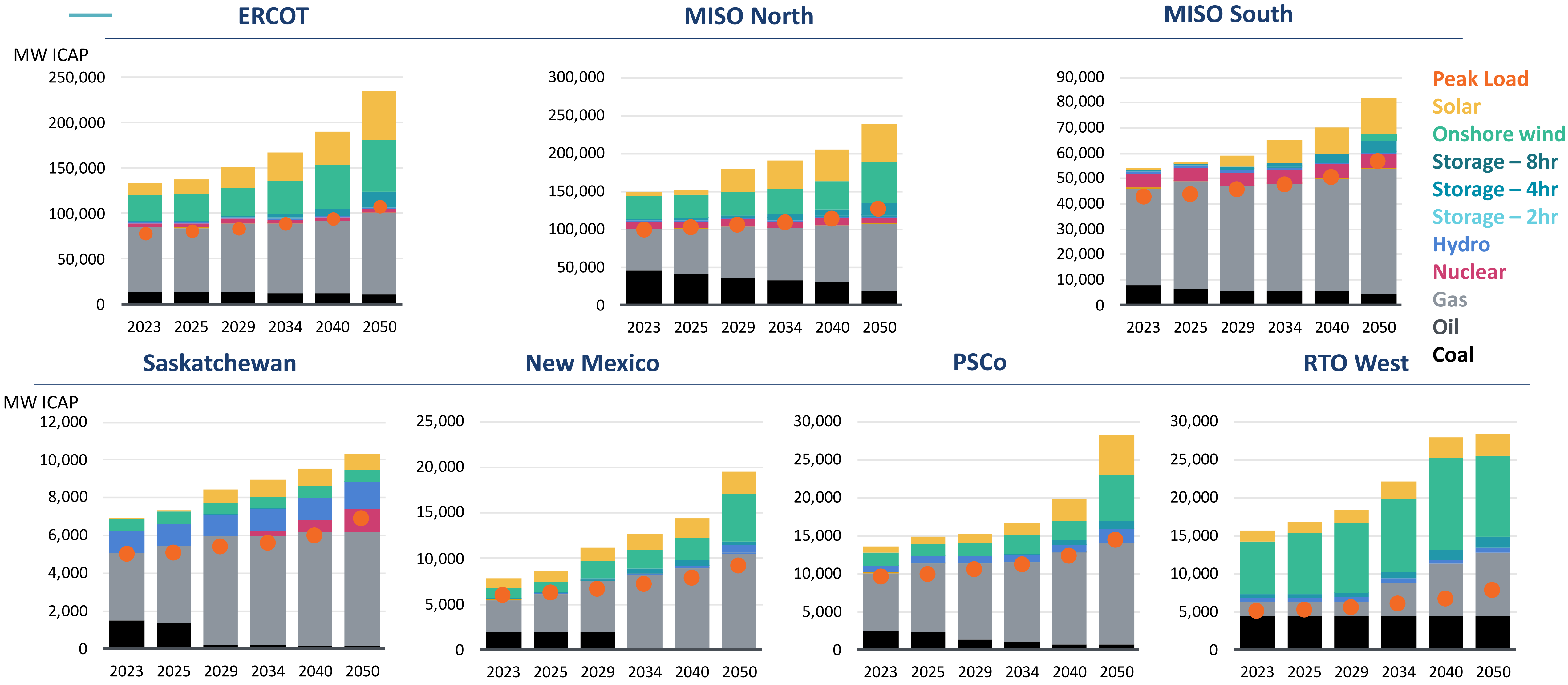
### Demand

- Historical hourly demand shape for each applicable external zone and 2006-2020 weather years, sourced from S&P Global Market Intelligence and Velocity Suite ABB, Inc.
- Demand scaled based on forecasted load growth by applicable balancing authority region for each future model year
- Electrification consistent with NREL Cambium 2020 "Moderate Scenario"
- Same across all FERNS scenarios

### Generation Capacity

- Existing capacity sourced from NREL Cambium 2020 and EIA NEMS data for applicable balancing areas that comprise external zones
- Forecasted additions and retirements consistent with NREL Cambium 2020 "Moderate Scenario" modeling (see next slide)
- Fuel costs and unit operational characteristics are sourced from comparable inputs to SPP's ITP 2025 parameters for other regions
- Same across all FERNS scenarios

# Representation of Neighboring Regions (MW Installed Capacity)




*Note: Axes differ across all charts. External zone capacity is the same across all FERNS scenarios. Forecasted capacity is informed by NREL 2020 Cambium Moderate Scenario buildout for applicable balancing areas as determined by transmission topology most connected to SPP.*

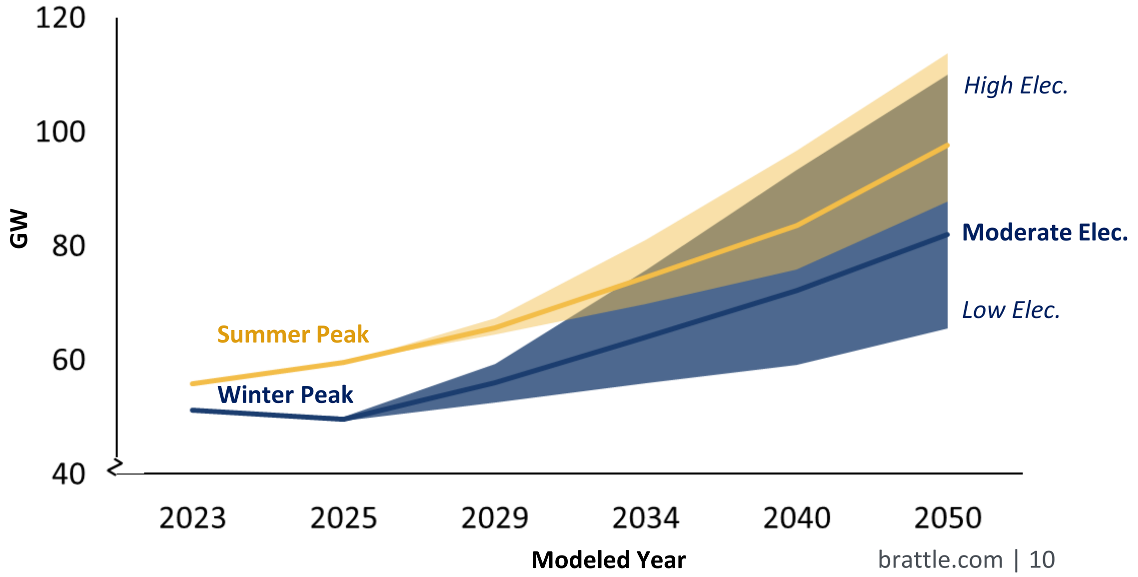
# Demand Scenario Overview

- For the FERNS effort, we model three electrification load scenarios, consistent with the FERNS Demand Electrification Study completed by Evolved Energy Research (EER).
- Low, moderate, and high electrification assumptions drive variations in SPP loads through 2050.
  - Scenarios differ in pace of customer driven electrification of the transportation, building, and industrial sectors.
  - All three electrification scenarios account for forecasted data center load.
  - No scenarios account for hydrogen electrolysis.
  - Hourly load forecasts differ for each demand scenario. Additionally, they vary by future simulation year and across the 15 SPP-supplied weather years (2006-2020).
  - Supplemental extreme weather events were added to capture risk conditions experienced in 2021 and 2022 winter storms.
- For more detailed information on the factors driving electrification assumptions developed for FERNS scenarios, see Future Load Scenarios for Southwest Power Pool (September 2024) by Evolved Energy Research.

**FERNS Study Scenarios**

| Electrification | Carbon Free Resource Shares: Low | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|---|
| Low | | A1 | B1 |
| Moderate | | A2 | B2 |
| High | | | B3 |

**SPP Peak Load for FERNS Scenarios**



# Demand Data Inputs – Low Electrification

Based on the level of electrification found in the U.S. 2023 Annual Energy Outlook. This represents a business-as-usual Scenario with low levels of electric technology uptake through 2050.

### FERNS Study Scenarios

| Electrification | Carbon Free Resource Shares: Low | Moderate | High |
|---|---|---|---|
| Low | | A1 | B1 |
| Moderate | | A2 | B2 |
| High | | | B3 |

### Low Electrification

| Zones | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| **Summer Peak (MW)** | | | | | | |
| North | 6,163 | 6,557 | 7,197 | 7,973 | 8,666 | 9,869 |
| North Central | 7,618 | 8,126 | 8,788 | 9,566 | 10,350 | 11,904 |
| Central West | 1,402 | 1,474 | 1,652 | 1,755 | 1,876 | 2,190 |
| Central East | 13,163 | 14,171 | 15,244 | 16,566 | 17,961 | 20,784 |
| Southwest | 7,271 | 7,796 | 8,486 | 9,280 | 10,235 | 11,978 |
| Southeast | 20,862 | 21,947 | 23,514 | 25,202 | 27,386 | 31,821 |
| ***SPP*** | ***56,174*** | ***59,674*** | ***64,408*** | ***69,834*** | ***75,895*** | ***87,797*** |
| **Winter Peak (MW)** | | | | | | |
| North | 7,250 | 7,402 | 7,937 | 8,505 | 8,970 | 9,769 |
| North Central | 5,974 | 6,103 | 6,610 | 7,124 | 7,572 | 8,407 |
| Central West | 1,240 | 1,253 | 1,203 | 1,225 | 1,164 | 1,331 |
| Central East | 11,268 | 11,399 | 12,168 | 12,986 | 13,722 | 15,194 |
| Southwest | 5,664 | 5,404 | 5,900 | 6,398 | 6,919 | 8,077 |
| Southeast | 20,172 | 18,033 | 19,143 | 20,086 | 21,113 | 23,435 |
| ***SPP*** | ***51,216*** | ***49,247*** | ***52,553*** | ***55,913*** | ***59,032*** | ***65,554*** |
| **Annual Load (GWh)** | | | | | | |
| North | 43,416 | 44,959 | 49,313 | 54,129 | 58,410 | 65,959 |
| North Central | 37,164 | 38,887 | 43,189 | 47,876 | 51,899 | 59,130 |
| Central West | 8,189 | 8,392 | 8,323 | 8,712 | 9,023 | 9,999 |
| Central East | 64,423 | 67,431 | 74,220 | 81,995 | 88,747 | 101,422 |
| Southwest | 39,244 | 41,017 | 44,951 | 49,372 | 53,750 | 61,701 |
| Southeast | 105,364 | 108,665 | 117,500 | 126,807 | 136,428 | 155,265 |
| ***SPP*** | ***297,800*** | ***309,351*** | ***337,497*** | ***368,891*** | ***398,256*** | ***453,476*** |

*Note: SPP seasonal peaks are coincident.*

# Demand Data Inputs – Moderate Electrification

The moderate scenario has a modest degree of electrification through 2050, primarily in transportation. Moderate amounts of building electrification will result in growth of winter peaks, but SPP remains summer peaking (in aggregate).

### FERNS Study Scenarios

| Electrification | Carbon Free Resource Shares: Low | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|---|
| Low | | A1 | B1 |
| Moderate | | **A2** | **B2** |
| High | | | B3 |

### Moderate Electrification

| Zones | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| **Summer Peak (MW)** | | | | | | |
| North | 6,117 | 6,528 | 7,438 | 9,005 | 10,362 | 12,153 |
| North Central | 7,564 | 8,087 | 8,843 | 9,912 | 10,965 | 12,650 |
| Central West | 1,407 | 1,471 | 1,684 | 1,881 | 2,090 | 2,381 |
| Central East | 13,057 | 14,108 | 15,460 | 17,666 | 19,726 | 22,893 |
| Southwest | 7,237 | 7,781 | 8,567 | 9,644 | 10,932 | 13,051 |
| Southeast | 20,805 | 21,919 | 23,902 | 26,691 | 29,861 | 34,983 |
| ***SPP*** | ***55,886*** | ***59,494*** | ***65,585*** | ***74,449*** | ***83,661*** | ***97,736*** |
| **Winter Peak (MW)** | | | | | | |
| North | 7,217 | 7,436 | 8,385 | 9,975 | 11,396 | 12,861 |
| North Central | 5,948 | 6,142 | 6,940 | 7,942 | 8,853 | 9,976 |
| Central West | 1,284 | 1,319 | 1,383 | 1,572 | 1,747 | 1,901 |
| Central East | 11,227 | 11,535 | 13,089 | 15,186 | 16,959 | 18,963 |
| Southwest | 5,646 | 5,421 | 6,114 | 7,035 | 8,006 | 9,354 |
| Southeast | 20,166 | 18,243 | 20,498 | 23,153 | 25,679 | 28,990 |
| ***SPP*** | ***51,130*** | ***49,675*** | ***55,938*** | ***64,051*** | ***72,182*** | ***81,992*** |
| **Annual Load (GWh)** | | | | | | |
| North | 43,167 | 45,019 | 51,197 | 59,594 | 66,949 | 76,579 |
| North Central | 36,934 | 38,855 | 44,294 | 51,097 | 56,862 | 65,124 |
| Central West | 8,154 | 8,440 | 8,708 | 9,751 | 10,706 | 11,830 |
| Central East | 63,974 | 67,432 | 76,834 | 89,782 | 100,834 | 116,149 |
| Southwest | 39,069 | 40,965 | 45,686 | 52,092 | 58,622 | 68,479 |
| Southeast | 104,860 | 108,646 | 120,662 | 137,258 | 153,366 | 176,643 |
| ***SPP*** | ***296,159*** | ***309,356*** | ***347,382*** | ***399,574*** | ***447,339*** | ***514,803*** |

*Note: SPP seasonal peaks are coincident.*

# Demand Data Inputs – High Electrification

The high scenario explores rapid customer uptake of electric technologies across buildings, transportation, and industry. By 2050, 90% or more of demand-side technology stock has become electrified. SPP remains summer peaking ISO wide, but many regions become winter or dual peaking.

### FERNS Study Scenarios

| Electrification | | Carbon Free Resource Shares | | |
|---|---|---|---|---|
| | | Low | Moderate | High |
| | Low | | A1 | B1 |
| | Moderate | | A2 | B2 |
| | High | | | B3 |

### High Electrification

| Zones | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| **Summer Peak (MW)** | | | | | | |
| North | 6,059 | 6,552 | 8,038 | 10,861 | 13,783 | 16,531 |
| North Central | 7,471 | 8,065 | 9,148 | 10,903 | 12,860 | 15,061 |
| Central West | 1,424 | 1,472 | 1,845 | 2,196 | 2,592 | 2,948 |
| Central East | 12,942 | 14,090 | 15,855 | 19,058 | 23,138 | 27,827 |
| Southwest | 7,215 | 7,786 | 8,725 | 10,366 | 11,832 | 13,423 |
| Southeast | 20,891 | 21,857 | 24,028 | 27,759 | 32,507 | 38,097 |
| ***SPP*** | ***55,700*** | ***59,441*** | ***67,339*** | ***80,964*** | ***96,645*** | ***113,819*** |
| **Winter Peak (MW)** | | | | | | |
| North | 7,125 | 7,414 | 8,978 | 12,174 | 15,762 | 18,858 |
| North Central | 5,887 | 6,147 | 7,299 | 9,261 | 11,484 | 13,578 |
| Central West | 1,323 | 1,336 | 1,614 | 2,354 | 2,865 | 3,021 |
| Central East | 11,152 | 11,591 | 13,922 | 18,150 | 23,242 | 27,891 |
| Southwest | 5,606 | 5,402 | 6,313 | 8,120 | 9,561 | 10,696 |
| Southeast | 20,435 | 18,515 | 21,658 | 26,843 | 32,313 | 36,759 |
| ***SPP*** | ***51,181*** | ***49,977*** | ***59,218*** | ***75,701*** | ***93,367*** | ***109,990*** |
| **Annual Load (GWh)** | | | | | | |
| North | 42,677 | 45,052 | 54,377 | 71,163 | 87,888 | 102,747 |
| North Central | 36,528 | 38,850 | 46,453 | 57,948 | 70,105 | 82,571 |
| Central West | 8,154 | 8,471 | 9,993 | 13,479 | 15,726 | 15,955 |
| Central East | 63,400 | 67,445 | 79,635 | 100,626 | 122,109 | 143,751 |
| Southwest | 38,914 | 40,945 | 46,892 | 58,511 | 66,735 | 72,962 |
| Southeast | 104,617 | 108,635 | 123,127 | 149,464 | 176,498 | 202,374 |
| ***SPP*** | ***294,289*** | ***309,398*** | ***360,477*** | ***451,191*** | ***539,060*** | ***620,359*** |

*Note: SPP seasonal peaks are coincident.*

# Resource Adequacy Approach

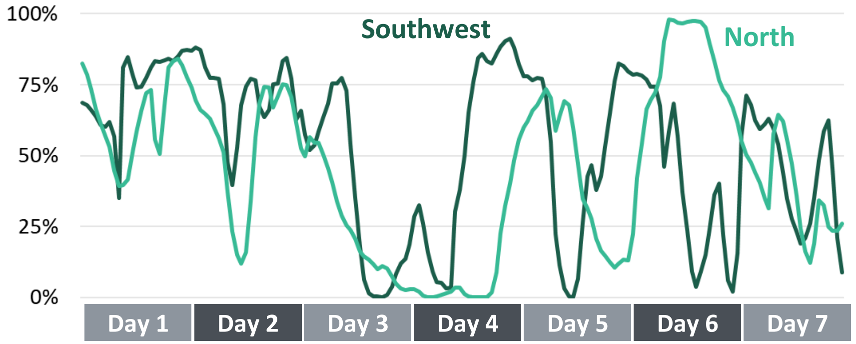
## Conventional approach to considering resource adequacy in expansion modeling:

- Based on forecasted **normalized summer peaks plus planning reserve margins**
- **Capacity accreditations** based on **ELCC values** (specified as a function of resource shares)
- Challenge: requires a lot of assumptions (about the nature of future resource adequacy challenges, ELCCs, and planning reserve margin) that will change significantly in an increasingly decarbonized and electrified future

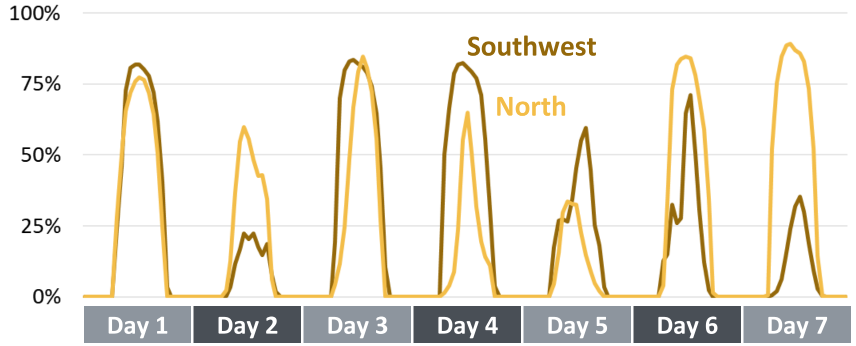
## FERNS "dynamic" hourly approach to resource adequacy:

- Create a **proxy weather year** based on load and renewable data for **15 weather years and added cold snaps** to approximate the expected future challenges SPP may experience
  - Heat waves, cold snaps, renewable droughts
  - Realistic seasonal, daily, hourly variations
- Each model year is represented by **26 three-day periods** that capture representative hourly conditions across all weather years. The 26 periods consist of 6 periods for each of the four seasons, one summer peak period, and one winter extreme weather period
  - Each 3-day period has a different probabilistic weight consistent with 8760 hours in 15 weather years
- The simulation balances supply and demand in every hour, including **operating reserve requirements.** This identifies when resource adequacy challenges could occur in the future
  - Future risk likely concentrated in certain months and hours outside of summer peaks
  - The model will choose generation investments and technologies capable of meeting needs
- The results inform when the existing RA frameworks may need to be modified in the future (but will need to be confirmed through probabilistic LOLE analyses with SERVM)

**Example: Hourly Wind Profiles**
(March 2020 Week in North and Southwest Regions)




**Example: Hourly Solar Profiles**
(March 2020 Week in North and Southwest Regions)




*Note: Renewable profile shown for a sample week in March 2020 to highlight hourly and geographic variation in the 15-year dataset. Profile expressed as hourly generation % of nameplate capacity.*

# FERNS Resource Adequacy Approach

Brattle's capacity expansion modeling employs our **Weather and Resource Adequacy Sampling (WRAS)** tool to create a weather-reflective proxy year with appropriately probability weighted multi-day periods:

- The tool selects probability-weighted proxy year periods based on multi-variable "k-means clustering" algorithm for gross load, net load (adjusted for weather-correlated forced fossil outages), and solar/wind profiles
- Each FERNS proxy year is comprised of 26 three-day periods (6 per season, summer peak, winter storm period). Each period is weighted based on the frequency of periods with similar conditions during the entire 15-year sample to capture multi-day events
- Weather representative proxy year eliminates the need for planning reserve margin and allows for hourly accreditation approach + operating reserve margin

The WRAS approach is computationally efficient, while accurately representing the full set of renewable and load conditions that drive resource adequacy challenges and unveiling the resource adequacy and energy market value of different resource types, including storage

# Brattle's Weather and Resource Adequacy Sampling (WRAS) Tool

Brattle's WRAS tool creates a weather-reflective proxy year with appropriately probability weighted multi-day periods reflecting the range of load, renewable, and generation outage conditions that are expected to occur over the course of 15-40 weather years. WRAS greatly enhances the representation of resource adequacy challenges (and how to address them) in capacity expansion and production cost simulations.

## INPUTS

**15-40 weather years of system-wide and zonal data:**

- Load forecasts for weather years
- Wind, solar, and hydro profiles (including multi-day renewable droughts and variable hydro conditions) for weather years
- Planned and forced generation outages (including high hot/cold weather outages)

WRAS

## OUTPUTS

- Proxy year composed of multi-day proxy periods (or proxy weeks)…
- … that reflects the renewable, load, and generation outage conditions that are expected to occur over many weather years
- Load and renewable/hydro generation profiles for each of the multi-day proxy periods
- Weights for each proxy period that reflect the expected frequency over entire weather sample

# Application of WRAS

**WRAS is a Brattle-developed approach for capacity expansion planning and production cost simulations that allows for greatly enhanced resource adequacy modeling with reasonable computational effort:**

- Feasibly compliments production cost and capacity expansion modeling by relying on multi-day proxy periods with respective weights to represent 8,760+ hours of data
- Allows for hourly resource adequacy modeling when integrated in capacity expansion modeling with combined hourly approach to resource adequacy (instead of the traditional planning reserve margin, normalized load, and static ELCCs)
- Eliminates the need for simplistic or computationally expensive projections of ELCC through endogenous modeling of resource accreditation within a capacity expansion or production cost simulation that captures full weather conditions
- Identifies periods with resource adequacy challenges over a 15-40 available weather years – and how challenges change with evolving resource mixes and load growth over time
- Meaningfully informs the relative severity of energy shortfall across the identified reliability events (severity of reliability events), especially because WRAS includes the tail-events of challenging weather, load, and generation outages.
- Overall, WRAS yields more realistic expansion planning and market simulation results:
  - Resource-adequate and more resilient (scenario-based) projections of generation expansion
  - Wholesale power prices (zonal or nodal), reflecting real-world scarcity conditions, resilience challenges, and geographic diversity
  - Congestion prices and congestion-related costs
  - Estimates of future generation investment and operating costs
  - Benefit-cost analyses for transmission planning and market reforms

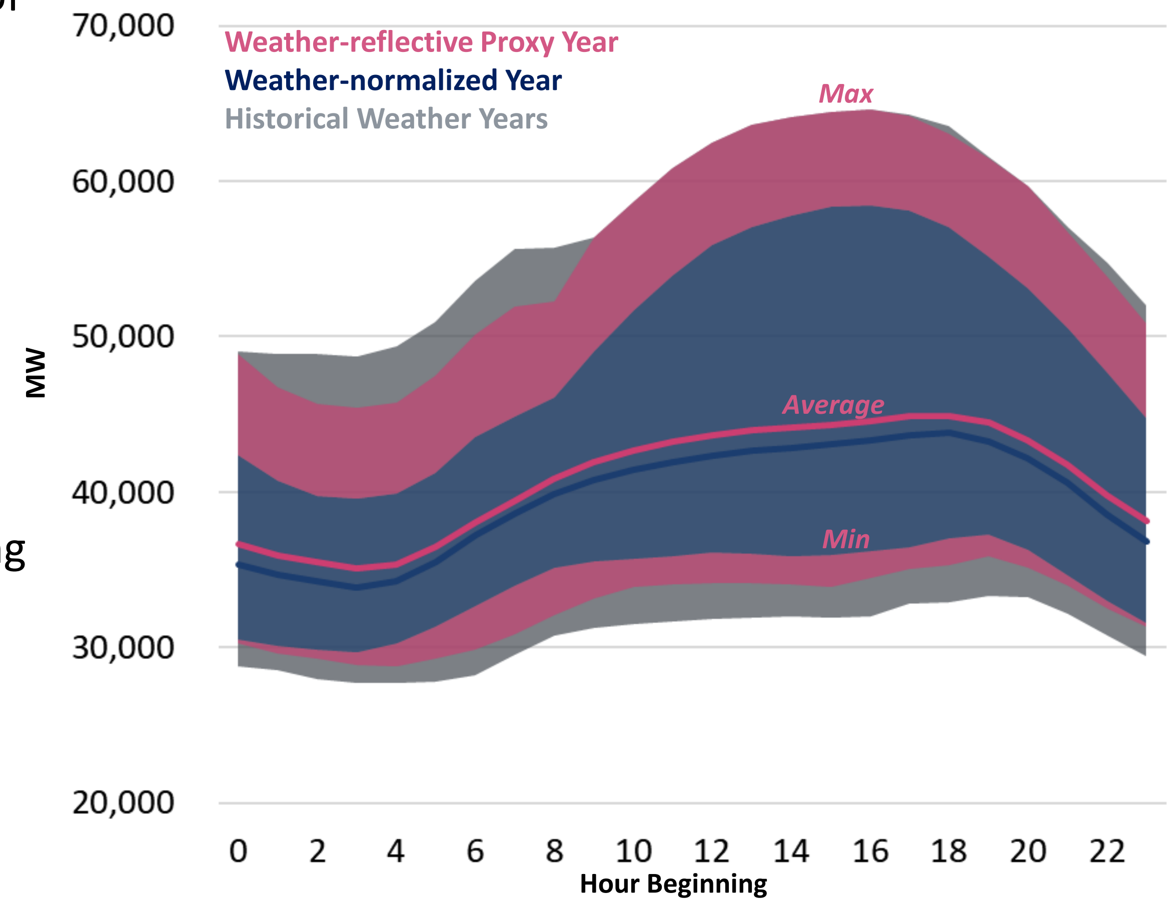
# Modeling Multiple Weather Years and Resource Adequacy Challenges

The weather-reflective proxy year captures the full range of weather conditions for the SPP-supplied 15 weather years, as shown in chart (unlike the weather-normalized years typically used in zonal and nodal economic modeling).

These weather-reflective FERNS simulation results include the **<u>expected resource adequacy challenges</u>** that SPP may actually experience in the future:

- FERNS modeling uses a $50,000/MWh "RA violation charge" to represent tradeoffs between adding generation capacity and allowing for load shedding (or operating reserve depletion) during the most challenging hours across all weather years
- At this level of the violation charge, RA violations (operating reserve depletions and/or load shed events) occur only during the modeled extreme winter periods (i.e., no more than once every 5-10 years)
- <u>Note</u>: The RA violation charge needs to exceeds typical estimates of the Value of Lost Load (VOLL) because the 1-in-10 year RA standard is more stringent than what could be justified economically with VOLL

**SPP-Wide 24-Hour Load Shape (2029, Moderate Scenario)**

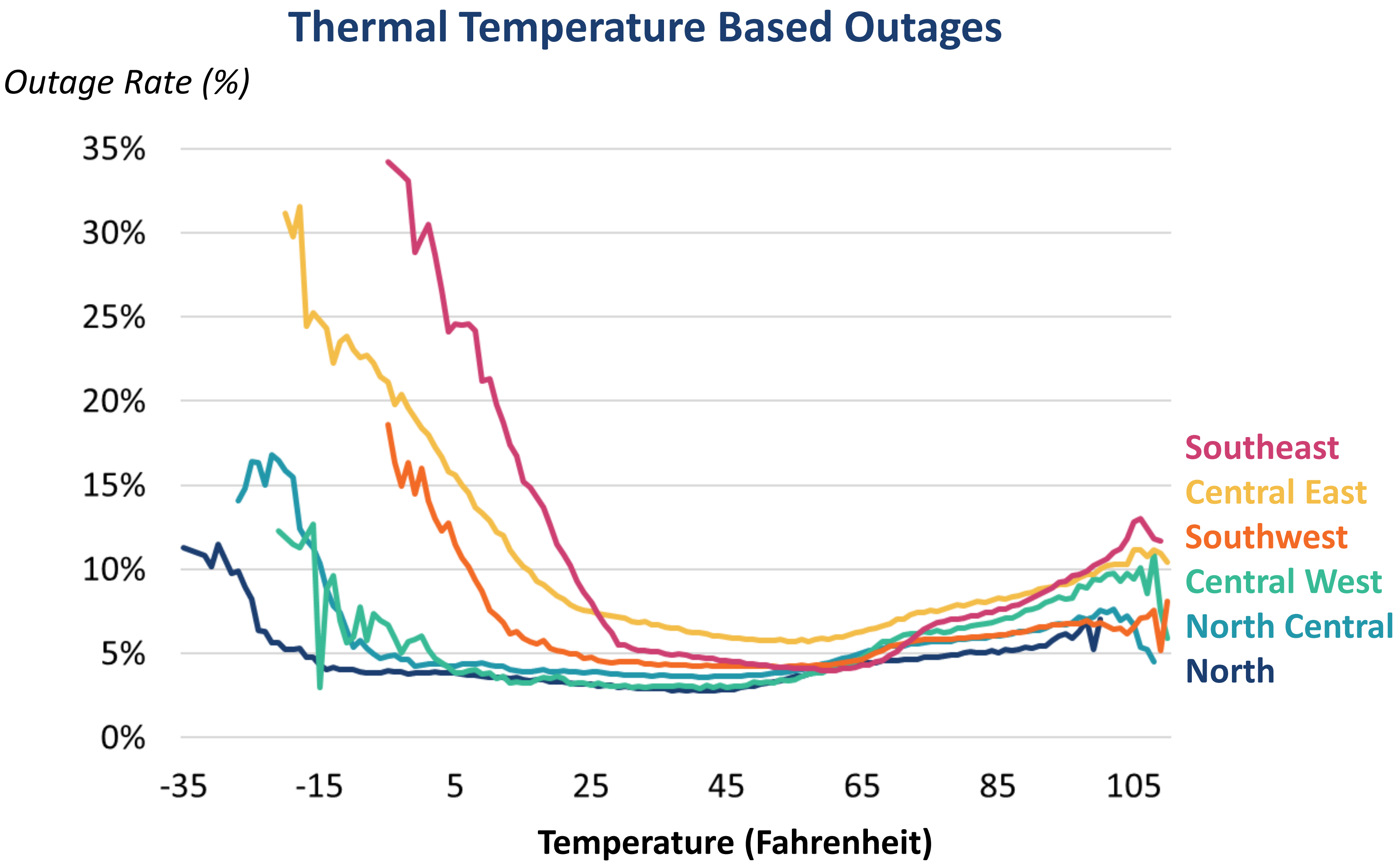



*The figure illustrates the range of hourly weather data in the 15-year sample. In grey in is the hourly minimum and maximum load values over each of the 2006-2020 weather years for 2029. The blue values are the min/max hourly values for a weather-normal proxy year of the 15-year sample. The pink is the WRAS proxy year which captures most of the max load values and some of the minimum load values over the 15 weather-variable years.*

# Weather-Correlated Thermal Generation Outages

FERNS modeling accounts for weather-dependent thermal outages, which vary by zone:

- SPP provided LOLE zonal temperature and outage relationships that we mapped to 2006-2020 hourly temperature curves by FERNS zone
- Outage rates are the same for all thermal units within a zone; no forced outages for solar or wind assets are modeled
- Thermal plants located in southern zones like Southeast, Central East, and Southwest are more prone to outages at cold temperatures relative to plants in northern zones that are often more winterized

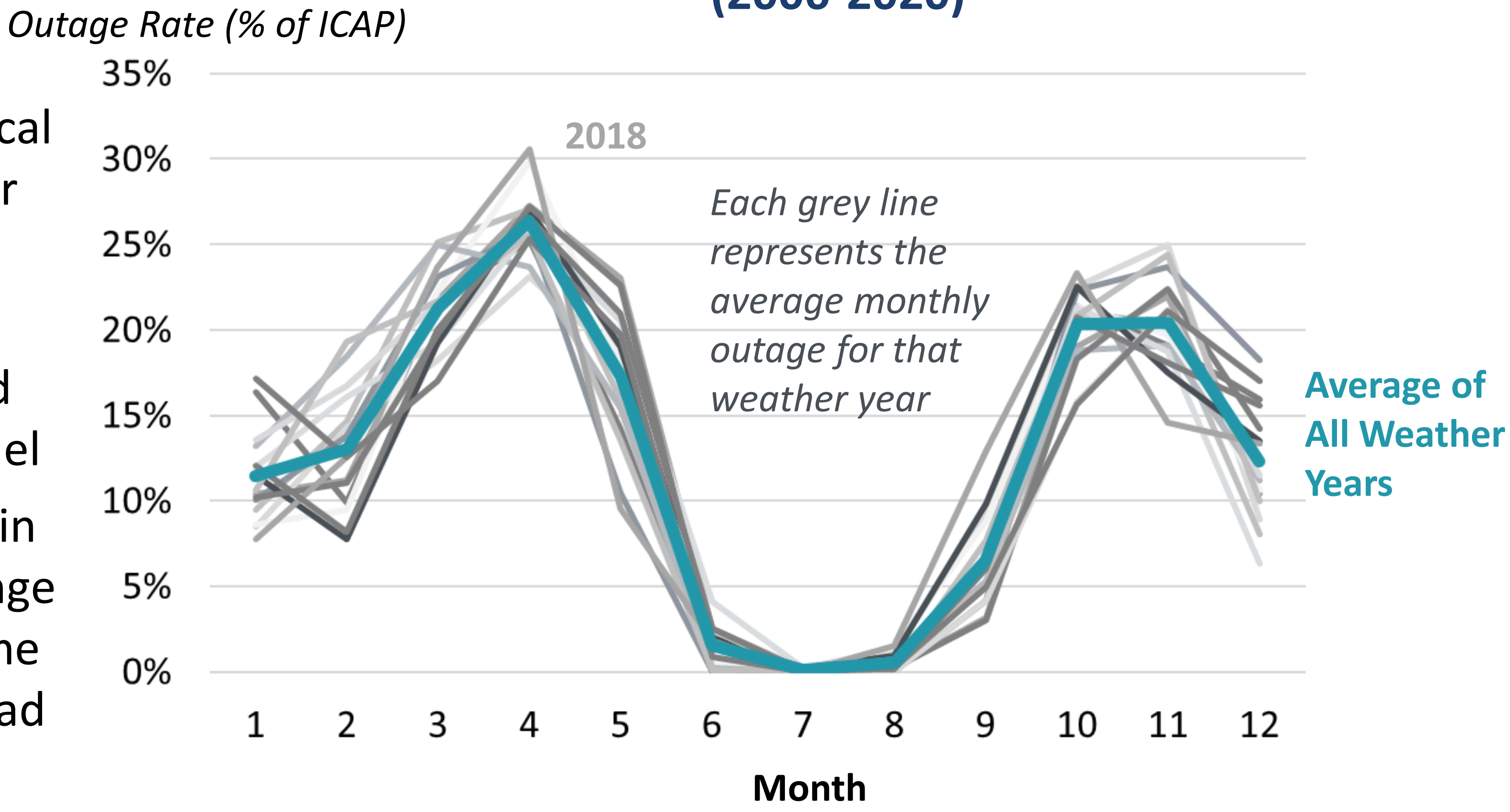


# Planned & Maintenance Outages

FERNS accounts for planned and maintenance outages in addition to weather-related outages

- SPP provides RTO-wide hourly historical planned and maintenance outages for 1980-2022
- We used the monthly averages of all weather years to capture the planned and maintenance outages in the model
- Planned outages could be scheduled in other months, if load conditions change in the future. FERNS assumes the same outage schedule because seasonal load trends are not forecasted to change significantly over time

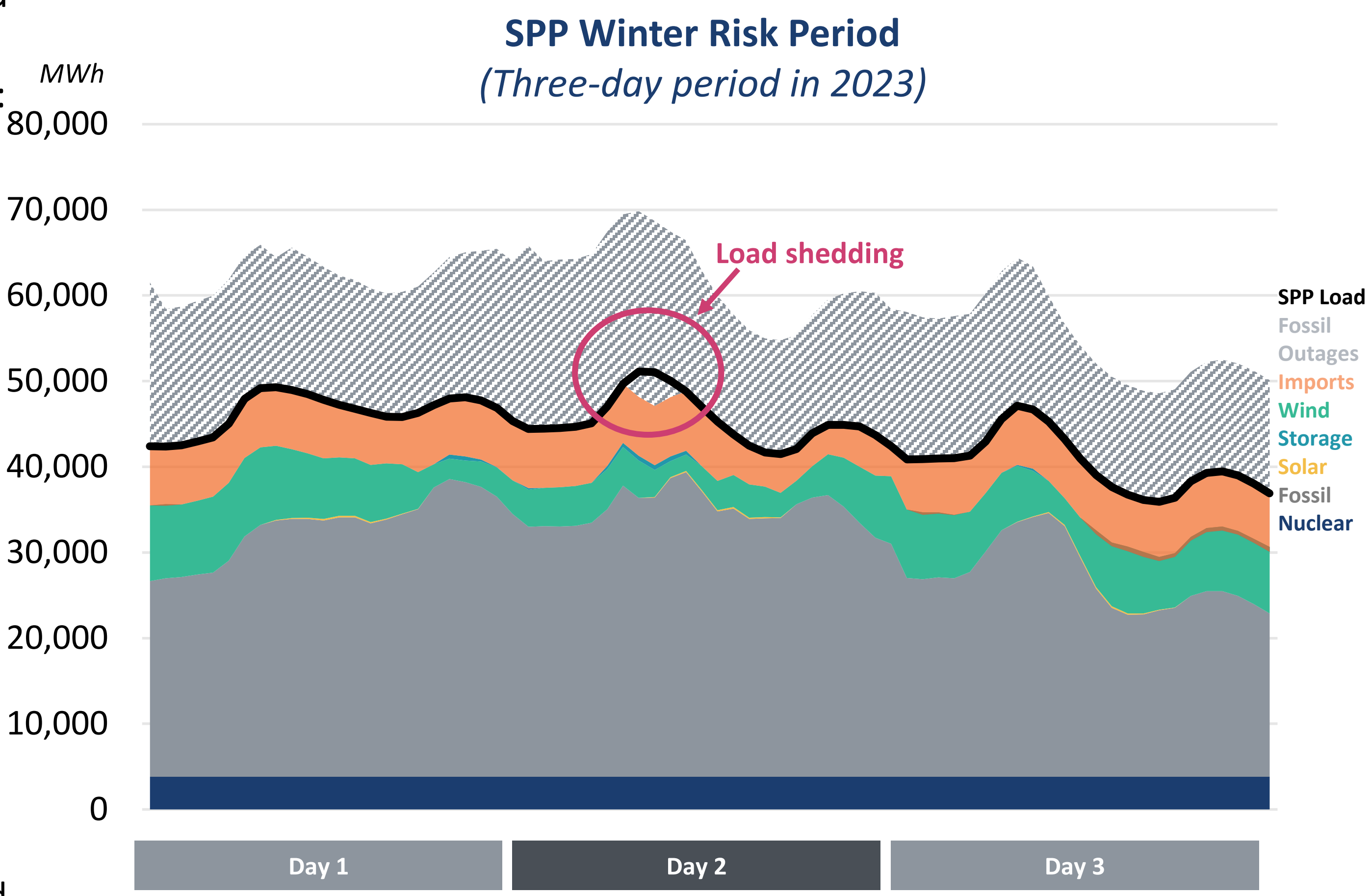
**Monthly Average SPP Generation Outage Rate (2006-2020)**



# Accounting for Extreme Weather

This FERNS modeling effort also includes a three-day period representative of severe winter storm conditions to ensure expansion results account for anticipated future conditions:

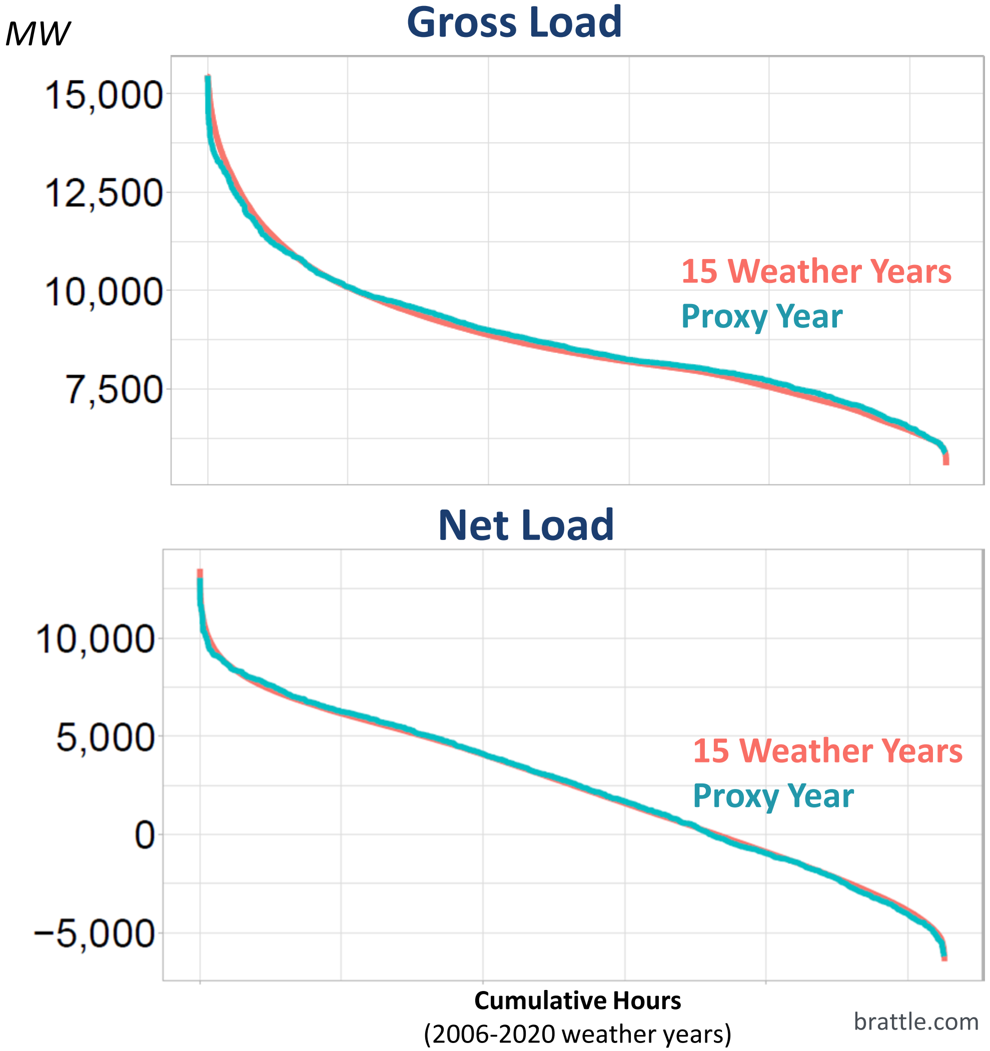
- The three-day period is weighted based on an assumed **1-in-7.5 year occurrence**
- Forecasted **SPP load conditions** are scaled based on Winter Storm Uri variations from forecasts (6% higher than projections according to the FERC Report 90/10 value)
- **Fossil outages** are based on REAL temperate outage curve (developed for SERVM simulations) and scaled to account for additional outages due to gas supply shortages. Scaling based on the SPP PRM recommendation to account for steps SPP has take steps to improve thermal fleet winterization.
- **Renewable profiles** are 40% of typical output, consistent with Figure 27 of the SPP Uri Report
- **Natural gas prices** are higher than monthly averages ($200/MMBtu) based on 2021 Uri conditions and historical SNL data
- External zones (representing MISO and ERCOT) are also adjusted to account for **multi-regional challenges** of weather events, reflecting the actual daily and hourly correlation/diversity across regions during the winter storm event



# Weather- and Resource-Adequacy Reflective Proxy Year

- Gross load and net load shown for Central East region for 2029 in moderate electrification scenario for all 15 weather years compared to WRAS proxy year
- Net load calculated with renewable generation profile for same 15 weather years, assumes SPP renewable capacity mix based on NREL Cambium Moderate Scenario
- 15 weather years of load and renewable data are represented by a single proxy year comprised of 26 three-day periods
  - Each period has a weight based on the frequency of periods with similar conditions occur for the entire 15-year sample
  - Periods are selected based on “k-means clustering algorithm” and selected based on gross load, net load, solar hourly capacity factor, and wind hour capacity factors for 2029 SPP wide data

**Example:**
**Central East 2029, Moderate Electrification**

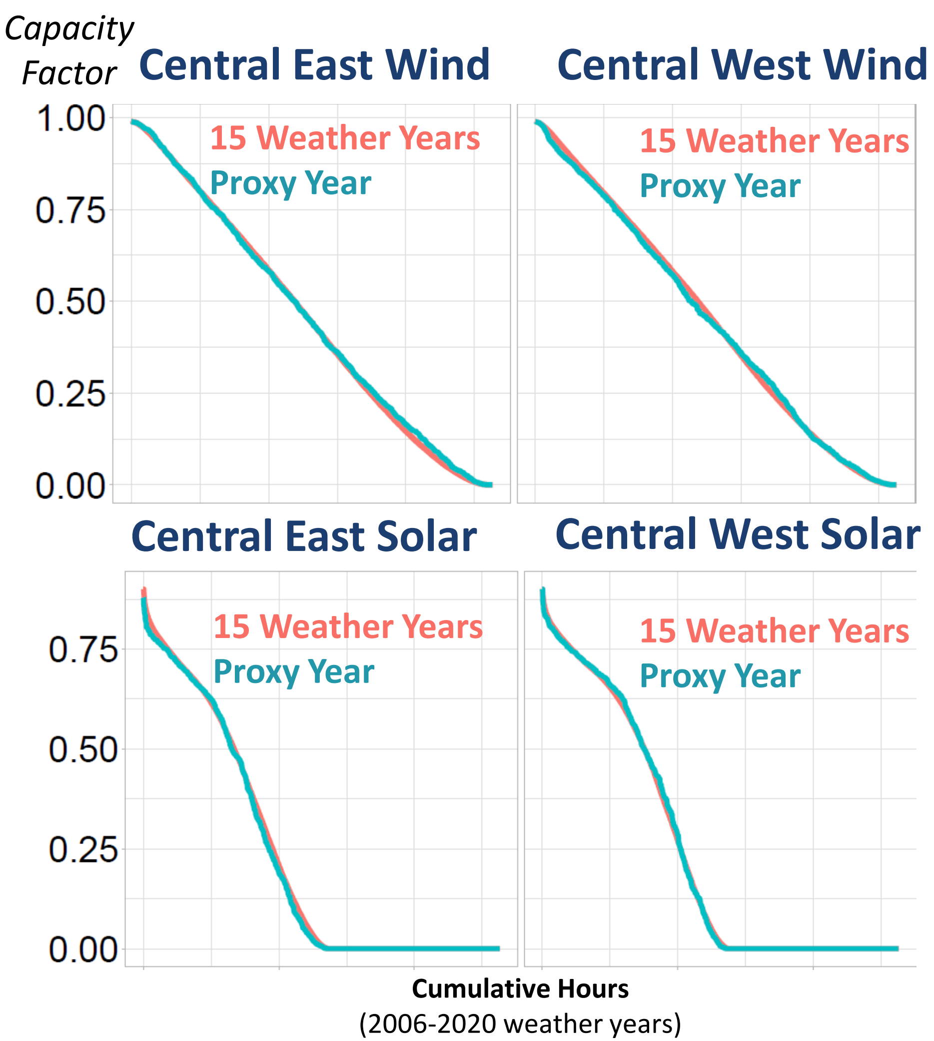



*Note: Vertical axis scales differ across figures. Net load is net of solar and wind generation.*

# Renewable Resource Profiles

- Renewable generation profiles vary by region within SPP to capture differences in resource conditions across the footprint
- The weather- and resource-adequacy-reflective proxy periods (and their associated weights) also represent the renewable conditions experienced during the past 15 years of weather data
  - Renewable generation profiles are shown as hourly capacity factors from 0-1, expressed as a fraction of installed capacity
  - Solar generates at 0% capacity factor for around half of the hours (overnight), while wind has closer to a 50% average capacity factor (true diagonal line)

**Example:**
**Wind & Solar in Central East and Central West**

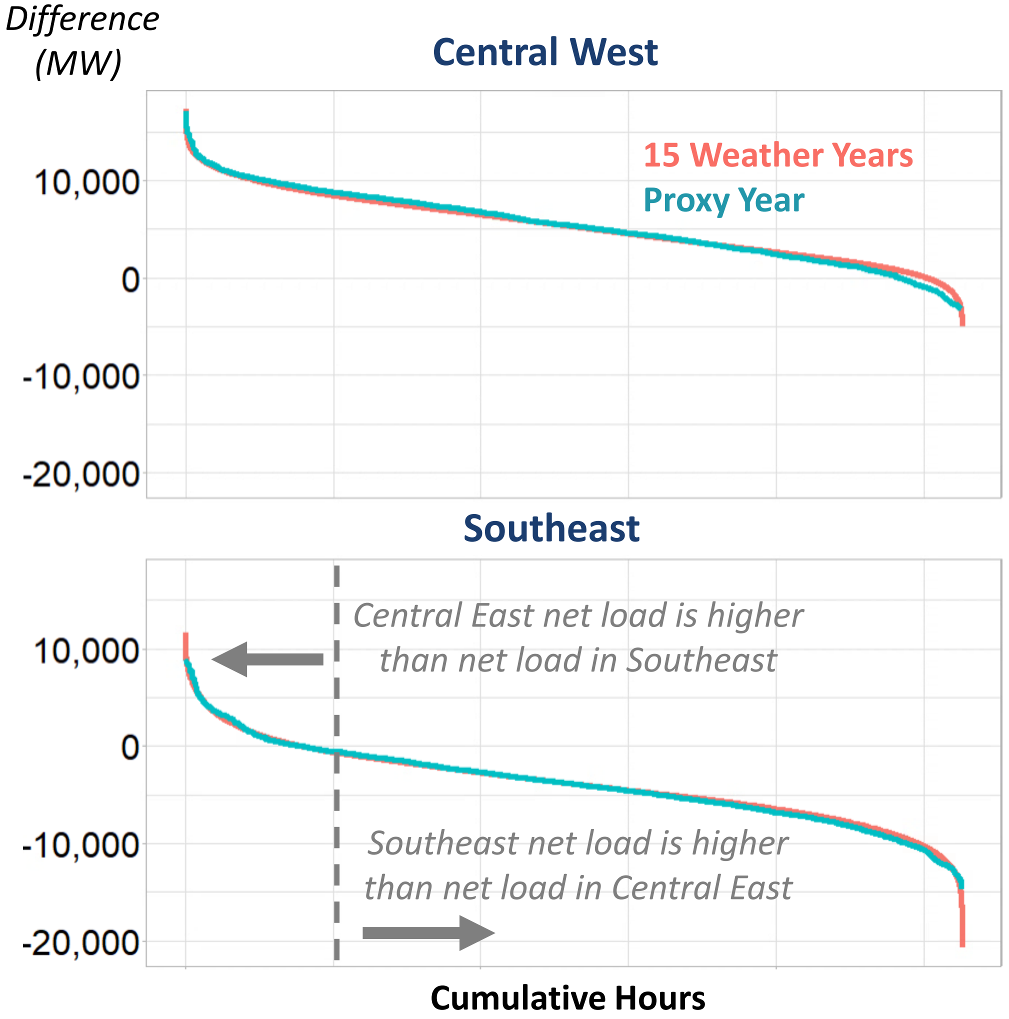



*Note: Charts show hourly capacity factors on a scale of 0-1, expressed as a fraction of installed capacity. Vertical axis scales differ across figures.*

# Approach to Geographic Diversity

- Geographic diversity between hourly renewable generation and loads of SPP zones helps reduce costs and improve resource adequacy
  - Variation in net load across regions suggests opportunities for transmission flows and could drive generation and transmission capacity build decisions
- We test how well our weather and resource adequacy-reflective proxy year captures the diversity between SPP regions by comparing net load difference duration curves between all pairs of simulated zones (for all 15 weather years)
- Example: Comparison of Southeast and Central West regions in the charts at the right
  - Shows that FERNS approach captures differences in net loads well in the proxy year

**Example**
**Difference between Central East vs. Central West and Southeast**
(2029 Moderate Electrification, Net Load)

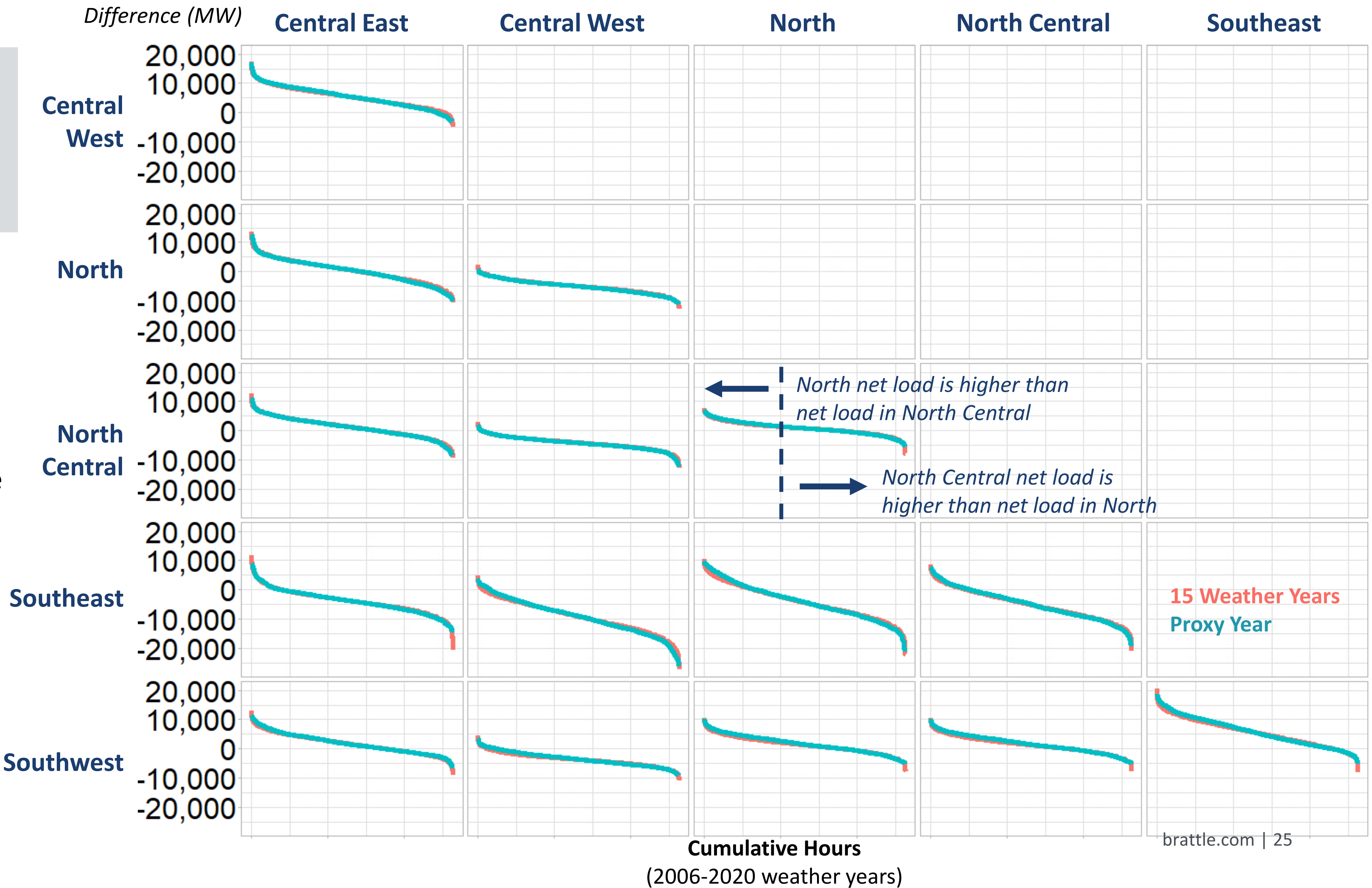



*Note: Charts show difference between Central East minus each region. When the charted net load is positive, Central East has higher net load than the other region. The charted net load is negative in hours when Central East net load is less than the compared regions. Vertical axis scales differ across figures.*

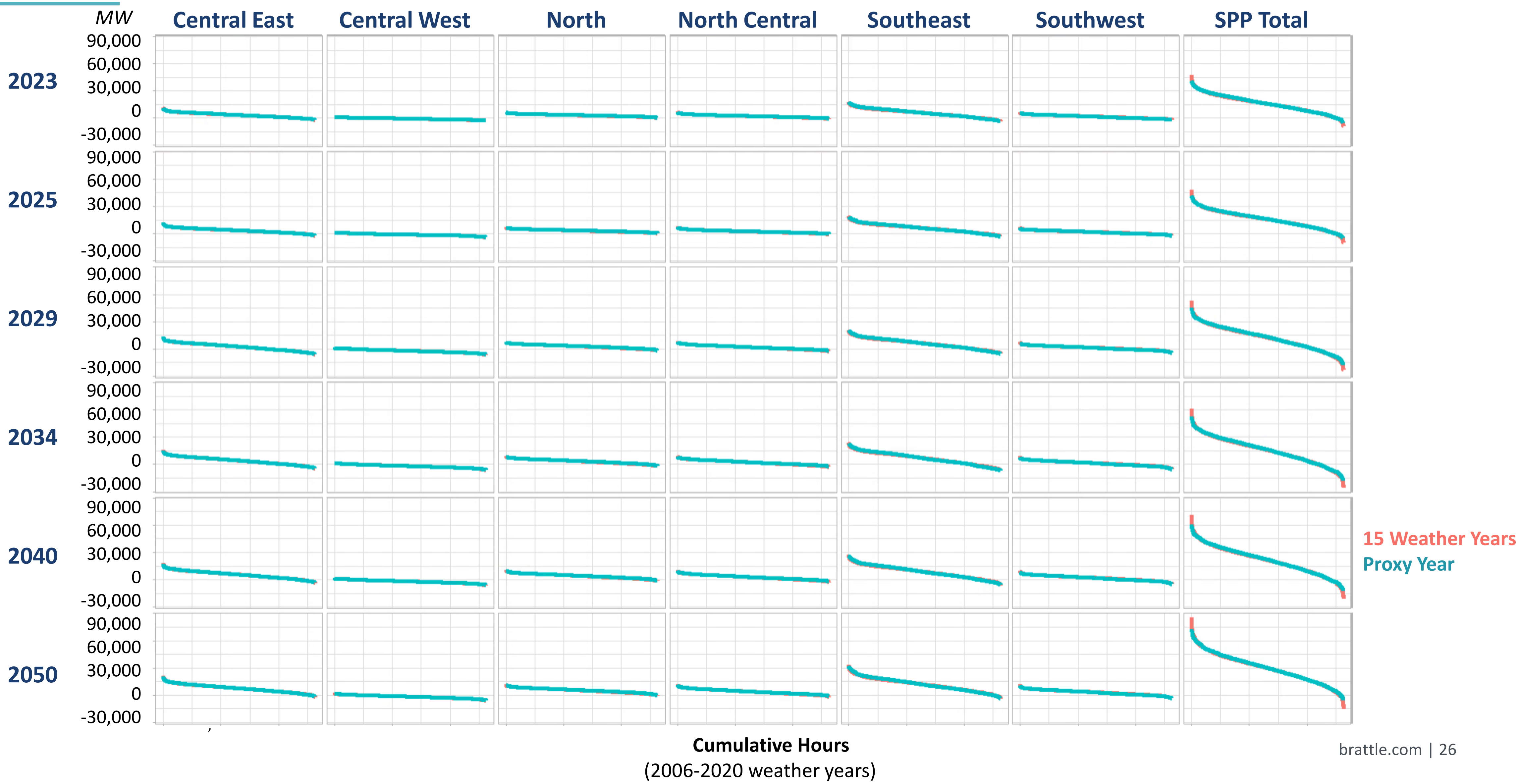
# Capturing Geographic Diversity

**Difference between Column Region vs. Row Region**
(2029 Moderate Electrification, Net Load)

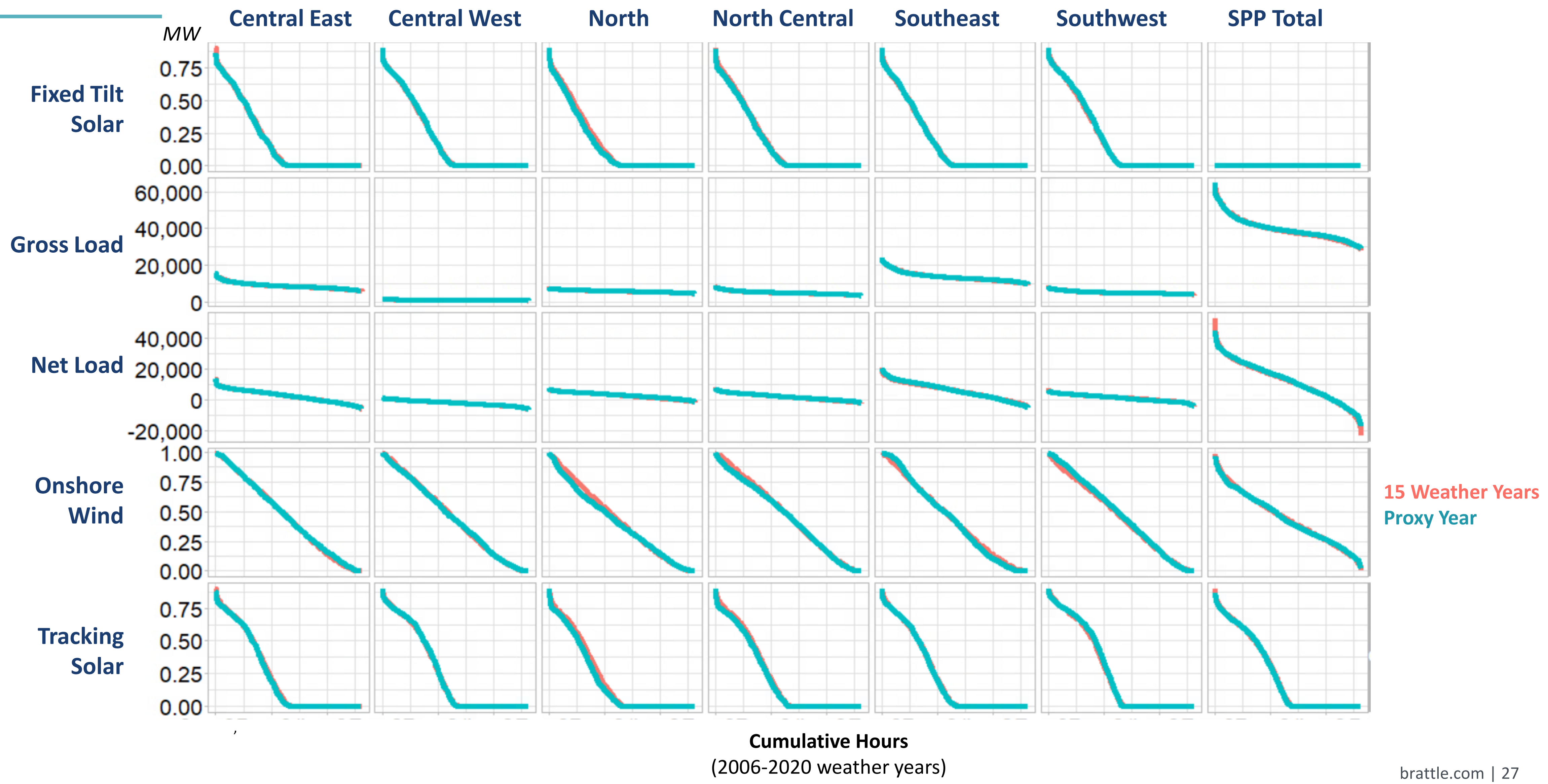
- Figure shows net load of region in column minus net load of region in row
- When the charted net load is positive, the column region has a higher net load than the row region
- The charted net load is negative in hours when the row region's net load is less than the column's region



# 2029 Moderate Electrification Net Load: All Model Years



# 2029 Moderate Electrification: All Profiles






*Note: Charts for renewables express hourly capacity factors on a scale of 0-1, as a fraction of installed capacity. Vertical axis scales differ across figures.*

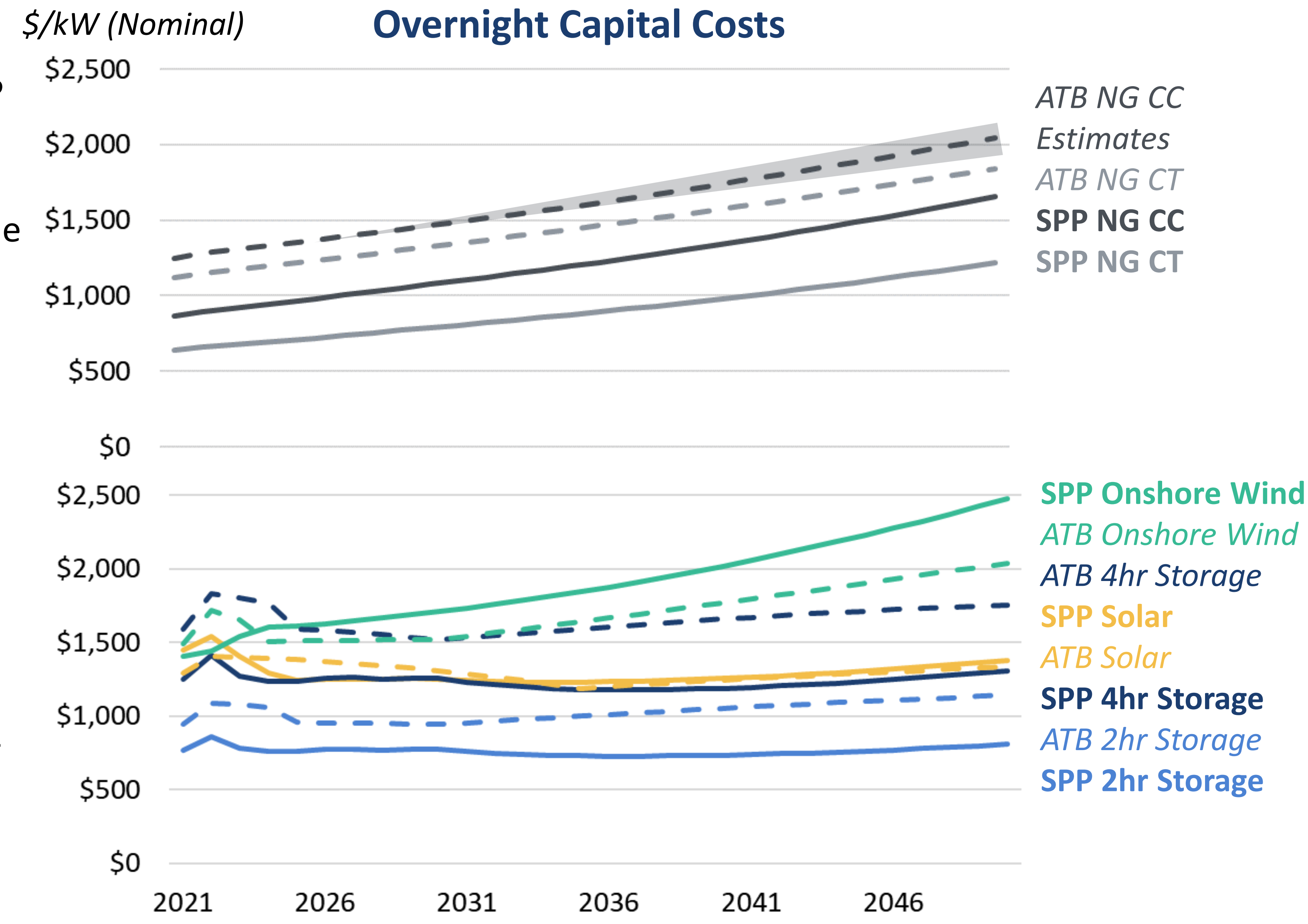
# Generation Technology Costs (and Benchmarking)

FERNS inputs are based on SPP 2025 ITP planning resource costs.

The charts also benchmark SPP costs against NREL Annual Technology Baseline (ATB) costs for the "moderate scenario"

- SPP costs are a lower for CCs and CTs than ATB moderate estimates
- Solar costs are close to ATB estimates, SPP wind costs are higher, and storage costs are lower than ATB moderate estimates. These assumptions will in part drive the simulated optimal resource mix.

Sensitivity analyses around cost inputs would be necessary to understand the extent of the tradeoff between assumed costs and optimal resource mix. For example, lower gas prices and higher solar costs would reduce the share of solar and storage, but increase reliance on natural gas and wind generation.



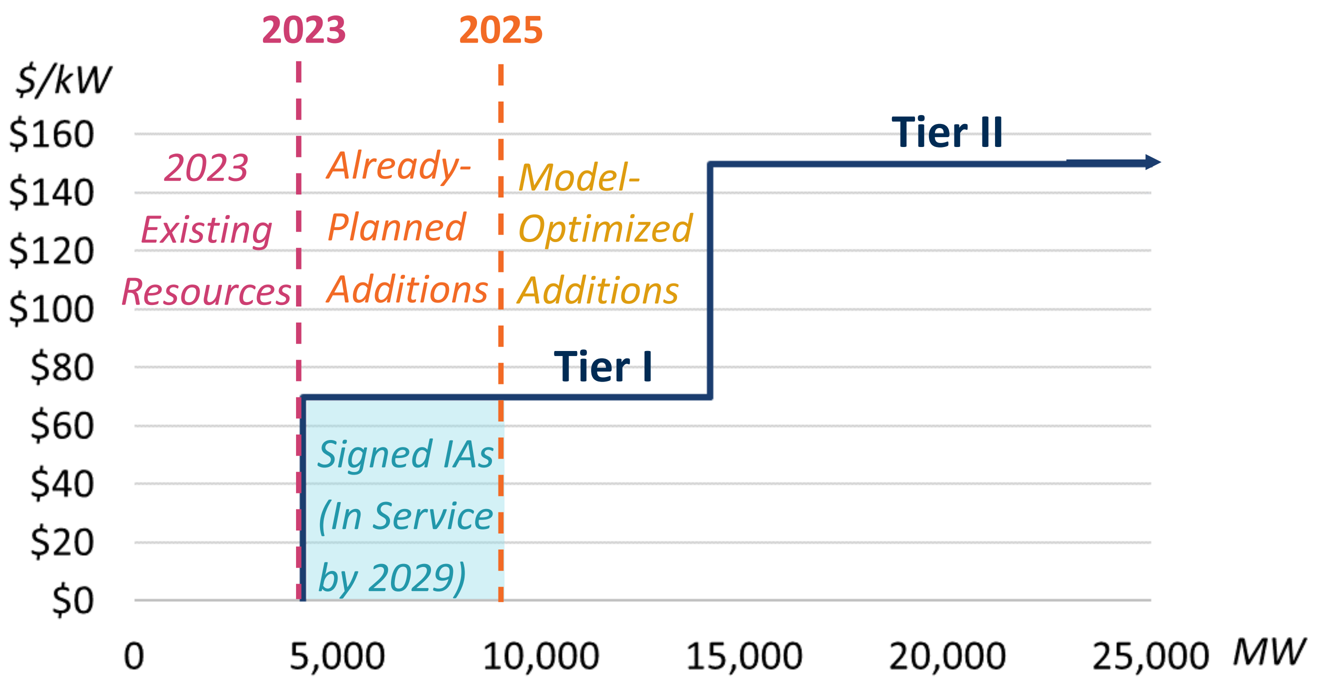

*Note: Vertical axis scales differ across figures. Grey shading for NG CCs is the range between the ATB conservative and aggressive scenarios. Dashed lines reference moderate ATB costs. ATB CT costs are the same for all scenarios.*

# Generator Interconnection Cost Methodology

FERNS modeling accounts for the increasing generator interconnection costs of resources at higher deployment levels

- Existing and planned resources will locate in regions with lower interconnection costs as reflected in Tier I capacity
- After Tier I capacity is built in each zone, additional renewable capacity will incur interconnection costs associated with Tier II

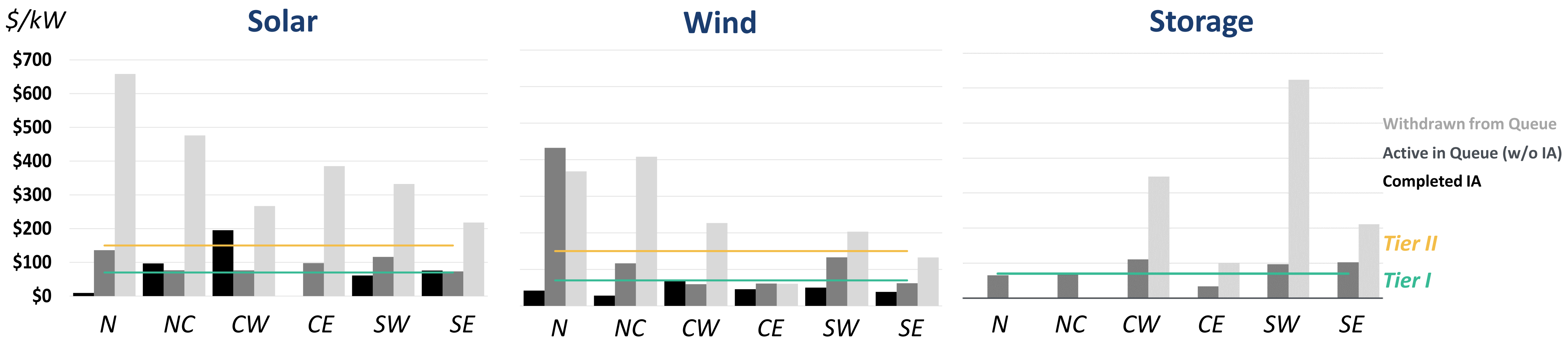
**Wind Interconnection Costs (Example)**




*Note: Interconnection costs will be additive to resource capital costs.*

# Renewable Generator Interconnection Cost Adders

- Renewable "supply curves" account for increasing generator interconnection costs at higher levels of penetration (new fossil plants are assumed to interconnect at existing generators' POIs)
- Interconnection cost adders are based on a [2023 LBNL study of SPP interconnection studies] and discussions with SPP Technical Review Committee (TRC) members for the FERNS effort
- Storage interconnection will only have one tier of costs since storage will likely be co-located with other resources
- Interconnection cost tiers are the same across resources and zones, but MW steps will vary by region and resource type:
  - Tier I: $70/kW, based on projects with completed interconnection agreements
  - Tier II: $150/kW, active projects without signed interconnection agreements and upper bound of cost-effective projects

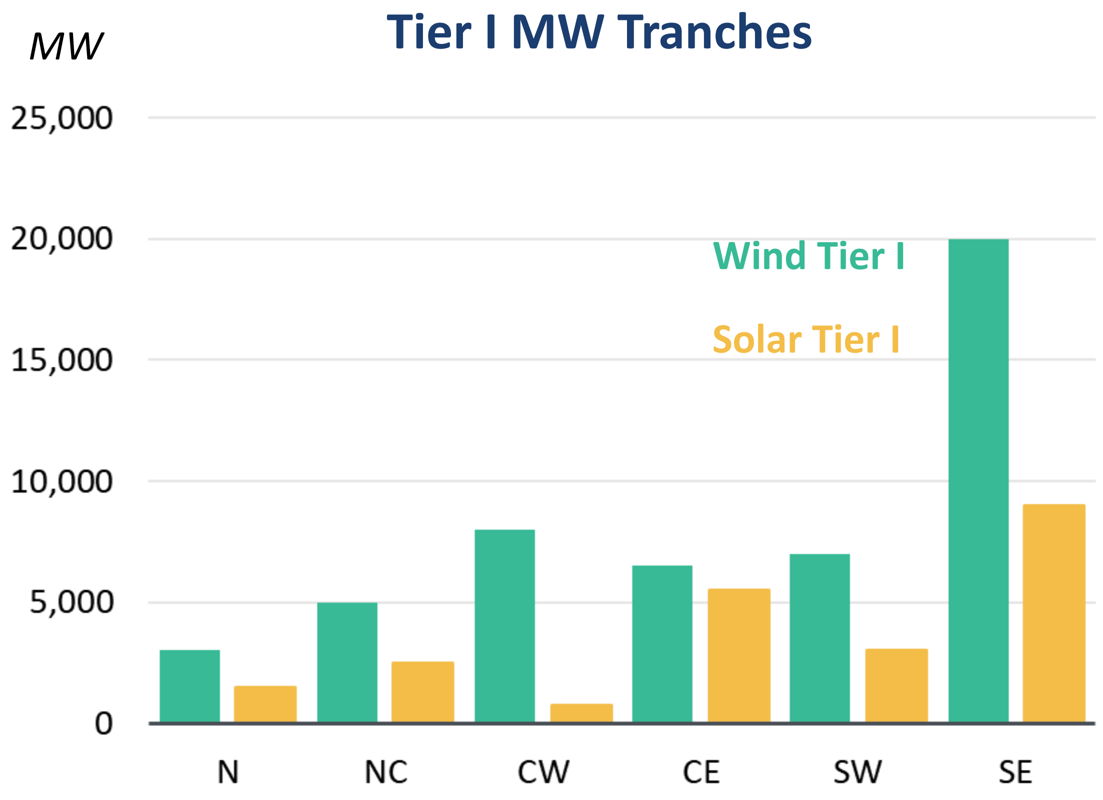



*Notes: The bars show 2023 LBNL average interconnection costs by project status. Lines show recommended interconnection costs for each tier.*

# Renewable Supply Curves: MW Tiers

Interconnection MW Tranches are primarily allocated based on 2023 and 2024 LBNL/SPP interconnection queue data

- Tier I Solar is based on capacity with completed IAs + 40% of fossil POIs, assuming some renewables can be co-located with fossil generators
- Tier I Wind is based on completed IAs + 40% of fossil POI
- Storage interconnection costs are not modeled in multiple tiers since storage will likely be co-located with other resources
- See next page for additional interconnection queue capacity analysis



# Renewable Supply Curves – Zonal Generator Interconnection Costs

**Interconnection Summary**

| | | | | North | North Central | Central West | Central East | South West | South East |
|---|---|---|---|---|---|---|---|---|---|
| 2023 Medium Peak Load | | [1] | *(MW)* | 6,953 | 7,564 | 1,407 | 13,057 | 7,237 | 20,805 |
| Current Installed Solar | | [2] | *(MW)* | - | 81 | 20 | 71 | 255 | 125 |
| Current Installed Wind | | [3] | *(MW)* | 3,301 | 3,498 | 4,168 | 5,810 | 4,596 | 12,076 |
| Current Installed Fossil | | [4] | *(MW)* | 4,051 | 6,083 | 1,434 | 13,484 | 6,645 | 22,485 |
| Cost Recommendations | Tier I | [5] | *($/kW)* | *$70* | | | | | |
| | Tier II | [6] | *($/kW)* | *$150* | | | | | |
| **Solar** | | | | | | | | | |
| 2023 Interconnection Solar | Completed IA | [7] | *(MW)* | 128 | 40 | 378 | - | 505 | 1,846 |
| | Active in Queue (w/o IA) | [8] | *(MW)* | 997 | 3,737 | 6,058 | 2,188 | 4,550 | 5,622 |
| | Withdrawn from Queue | [9] | *(MW)* | 260 | 1,428 | 976 | 625 | 4,413 | 559 |
| 2024 Interconnection Solar | Operational IA | [10] | *(MW)* | - | - | 20 | 10 | 195 | - |
| | Active in Queue (w/o IA) | [11] | *(MW)* | 4,201 | 6,650 | 14,643 | 4,464 | 12,925 | 20,374 |
| | Withdrawn from Queue | [12] | *(MW)* | - | - | 300 | - | - | 210 |
| Solar Capacity Recommendations | Tier I | [13] | *(MW)* | 1,750 | 2,500 | 1,000 | 5,500 | 3,000 | 10,000 |
| | Tier II | [14] | *(MW)* | *Unlimited* | | | | | |
| **Wind** | | | | | | | | | |
| 2023 Interconnection Wind | Completed IA | [15] | *(MW)* | 2,700 | 2,191 | 9,624 | 1,099 | 3,832 | 16,224 |
| | Active in Queue (w/o IA) | [16] | *(MW)* | 2,297 | 2,584 | 3,936 | 896 | 1,519 | 3,031 |
| | Withdrawn from Queue | [17] | *(MW)* | 2,602 | 2,566 | 10,960 | 1,663 | 9,815 | 9,242 |
| 2024 Interconnection Wind | Operational IA | [18] | *(MW)* | 1,450 | 2,489 | 8,139 | 1,098 | 4,238 | 12,344 |
| | Active in Queue (w/o IA) | [19] | *(MW)* | 5,803 | 5,862 | 11,837 | 996 | 4,321 | 12,388 |
| | Withdrawn from Queue | [20] | *(MW)* | - | 200 | - | - | - | - |
| Wind Capacity Recommendations | Tier I | [21] | *(MW)* | 4,000 | 5,000 | 10,000 | 6,500 | 6,500 | 23,000 |
| | Tier II | [22] | *(MW)* | *Unlimited* | | | | | |
| **Storage** | | | | | | | | | |
| Storage Capacity Recommendations | Tier I | [23] | *(MW)* | *Unlimited* | | | | | |

Notes and Sources:

[7] - [9], [15] - [17]: 2023 Generator Interconnection Cost Analysis in the Southwest Power Pool (SPP) Territory

[10] - [12], [18] - [20]: 2024 Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection

[13]: Tier I solar recommendations are based on completed IA + 40% of fossil POI.

[21]: Tier I wind recommendations are based on completed IAs + 40% of the fossil POI.

[14], [22]: Tier II resources will be located farther away and require more expensive interconnection.

[23]: Storage interconnection costs are not modeled using tiers since storage will likely be collocated with other resources.

# Renewable Generation: Hourly Profiles and Capacity Factors

- Renewable generation profiles are based on the 8,760 profiles for each modeled weather year.
- Hourly generation profiles are sourced for all 15 SPP-selected weather years from College of London (renewables.ninja) and vary by zone in SPP.
- Additional benchmarking and adjustments were made to align regional variation with NREL's modeling of zonal resource conditions.
- Capacity factors for the proxy year are shown in the table.

**Annual Capacity Factors by Zone**
*(%, before curtailments, reflecting all 15 weather years)*

| | Onshore Wind | Tracking Solar | Fixed Tilt Solar |
|---|---|---|---|
| **North** | 41.09% | 25.08% | 17.94% |
| **North Central** | 42.58% | 26.57% | 19.26% |
| **Central West** | 42.62% | 29.10% | 20.42% |
| **Central East** | 41.42% | 26.18% | 18.35% |
| **South West** | 44.41% | 30.24% | 21.16% |
| **South East** | 42.56% | 26.71% | 18.97% |

*For additional documentation on renewable profiles see:*
*[1] Pfenninger, Stefan and Staffell, Iain (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265. doi: 10.1016/j.energy.2016.08.060*
*[2] Staffell, Iain and Pfenninger, Stefan (2016). Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output. Energy 114, pp. 1224-1239. doi: 10.1016/j.energy.2016.08.068*

# Renewable Support

The assumed level of Federal tax credit support (or similar future state or corporate policies) varies across FERNS scenarios to determine carbon-free penetration in the future

- High-carbon free **Scenarios B** assumed federal investment tax credit (ITC) and production tax credit (PTC) continue to support renewable development.
- ITC and PTC could be replaced by other types of support (e.g., state RPS goals, corporate clean energy targets, greenhouse gas mandates) to achieve comparable outcomes. Tax credits are assumed to remain available through 2050.
- Moderate carbon-free **Scenarios A** assume no new resources are eligible for ITC or PTC (only existing assets remain eligible).
- Because solar and wind resources in SPP have higher capacity factors compared to most other U.S. regions, they are assumed to select PTC instead of the ITC as the more lucrative option.
- FERNS does not model nuclear PTC because, under FERNS assumptions, no new nuclear assets are assumed to be available and come online.

**FERNS Tax Credit Assumptions**

*High Carbon-Free Scenarios (B1, B2, B3)*

| Resource Type | Investment Tax Credit (ITC) | Production Tax Credit (PTC) |
|---|---|---|
| **Solar** | X | $21.30/MWh through 2050 (inflation adjusted) |
| **Wind** | X | $21.30/MWh through 2050 (inflation adjusted) |
| **Storage** | 30%, assumed through 2050 | X |

*Note: The PTC variable value of $21.30/MWh was calculated based on a base $26/MWh amount, 10-year eligibility, single repowering, and levelized over the lifetime of the assets built through 2050 in the FERNS study. The $21.30/MWh reflects a post-tax value and benchmarked against historical SPP supply offer curves.*

# Transmission Expansion Costs

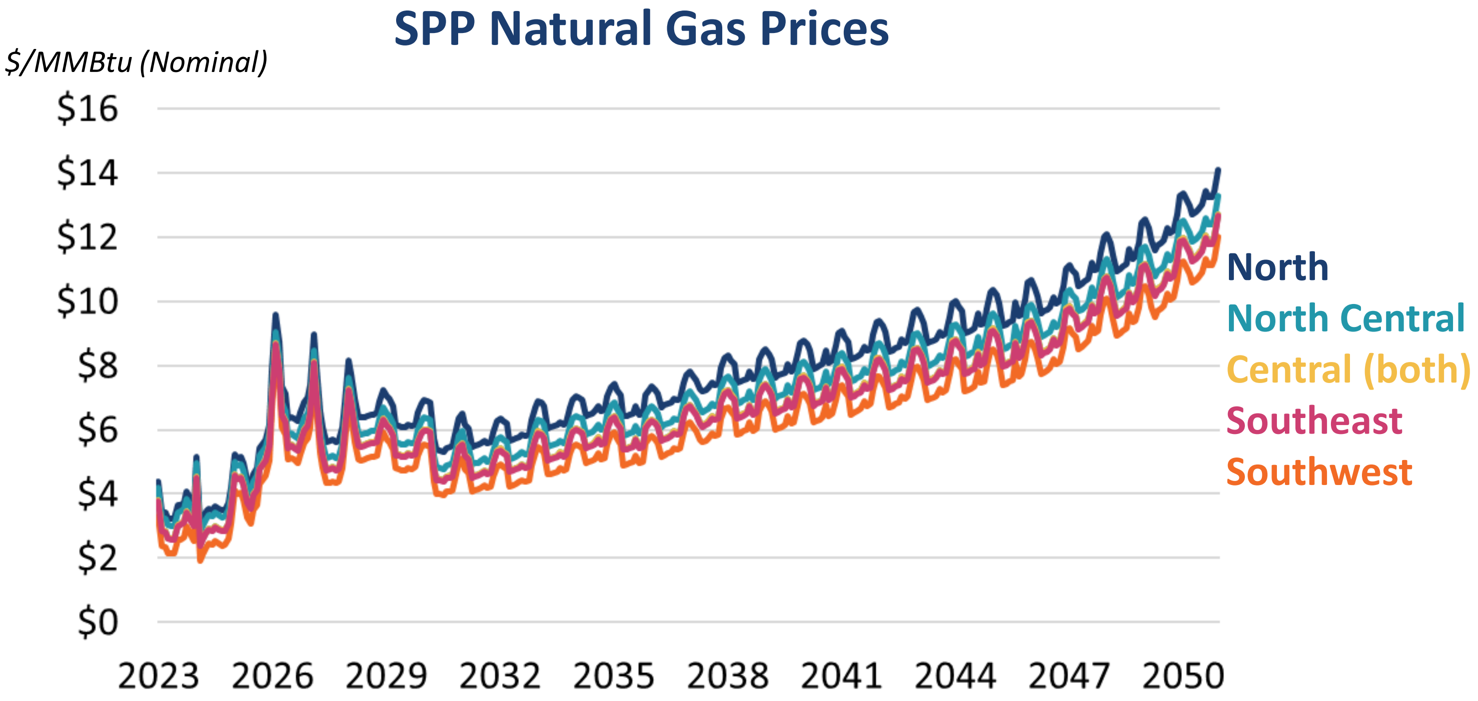
- Line cost based on SPP-provided 2024 estimates (from EPC contractor) for specific transmission projects
- Substation and transformer costs are based on MISO's Transmission Cost Estimate Guide (2023)
- All costs are adjusted to 2023$ (and based on a 2.6% inflation rate in simulations)

## SPP Transmission Expansion Costs

| | | | |
|---|---|---|---|
| **Inputs** | | | |
| Number of Substations | [1] | 3 | |
| Contingency Based Limit (MW) | [2] | 1,000 | |
| Number of Transformers (345 kV/115 kV) | [3] | 3 | |
| Miles between lines | [4] | 200 | |
| MVA Rating | [5] | 1,500 | |
| **Assumptions** | | | |
| Substation Cost ($) | [6] | $15,100,000 | Assumes 4 positions (ring bus), MISO 2023 Transmission Cost Estimation Guide p. 41 |
| Voltage Transformer Cost | [7] | $9,829,500 | $/MVA x [5], MISO 2023 Transmission Cost Estimation Guide p. 25 |
| New Single Circuit 345 kV Line Cost ($/Mile) | [8] | $2,820,858 | Assumes single circuit transmission line, average of costs from 2024 estimates from EPC contractor for real lines ($2023) |
| Levelization Factor | [9] | 8% | Internal assumption based on revenue requirement buildup with 6.8% discount rate and 40 year line lifespan (includes taxes, depreciation, and O&M costs) |
| Interface Cost Allocation Share | [10] | 2 | Based on assumption that expansion will be necessary in multiple interfaces to accommadate increased flows |
| **Cost Estimate** | | | |
| Total Transmisson Costs ($) | [11] | $638,960,040 | [1] x [6] + [3] x [7] + [4] x [8] |
| **Expansion Costs ($/MW)** | **[12]** | **$319,480** | ([11]) / ([10] x [2]) |
| **Annual Expansion Costs ($/MW-yr)** | **[13]** | **$26,295** | ([11] x [9]) / ([10] x [2]) |

# Natural Gas Prices

- Natural gas prices for internal and external zones vary by region.
- Modeled zones are mapped to gas hubs in SPP provided ITP 2025 forecasts based on gas units' Powerflow Area Numbers with regional basis differentials used to adjust Henry Hub forecasts.
- Prices are adjusted using an annual inflation rate of 2.6% (price spike during winter storm period not shown in chart).
- SPP forecasted ITP 2025 prices are generally higher than some other national forecasts (NREL, EIA's AEO).
- The impacts of lower gas price projections would need to be studied in further sensitivity work.

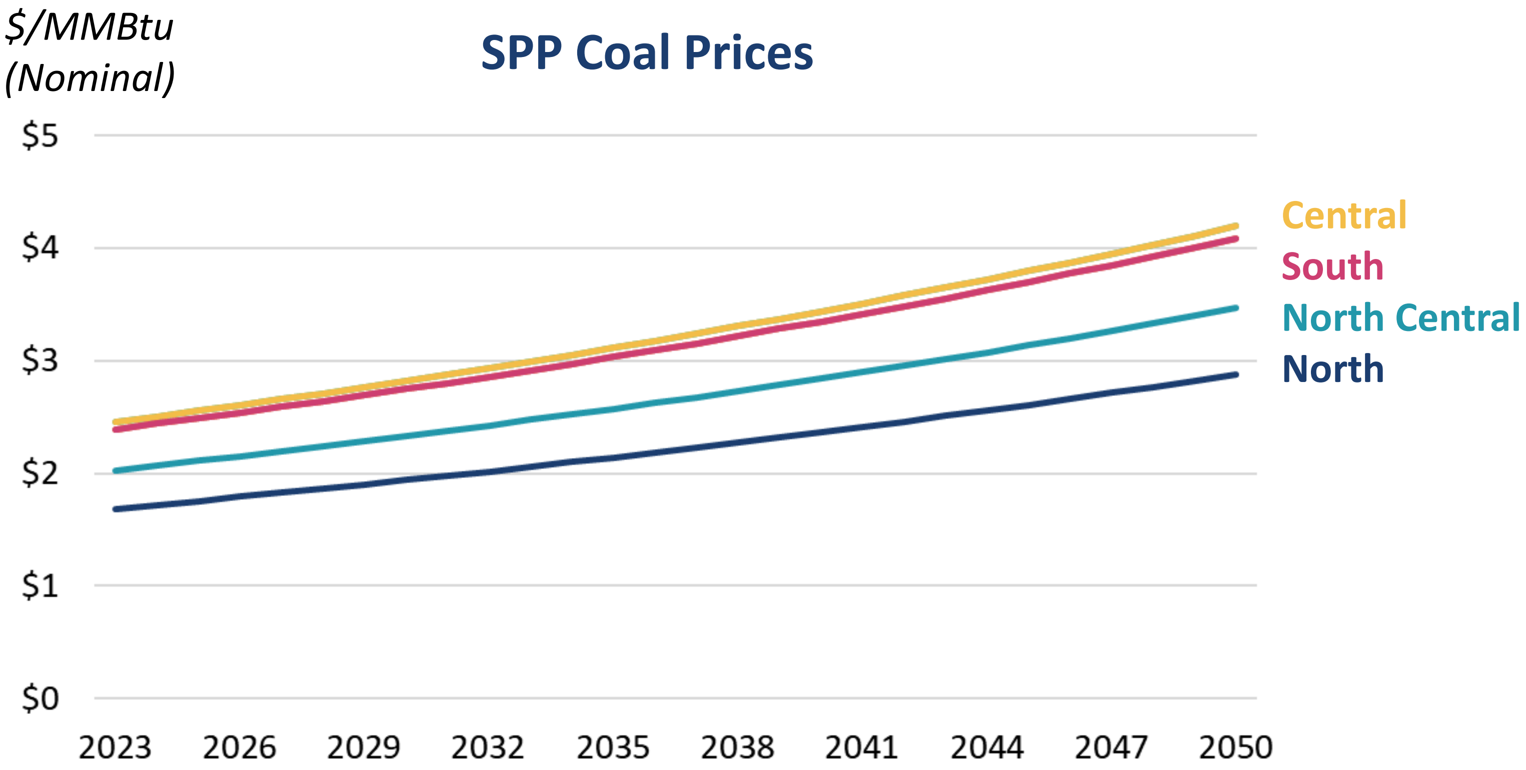



## Gas Price Hub Mapping

| Zones | Gas Price Hubs |
|---|---|
| North | NG Dakotas |
| North Central | NG Nebraska |
| Central West | NG KSMO |
| Central East | NG KSMO |
| Southwest | NG West SPP |
| Southeast | NG Oklahoma |

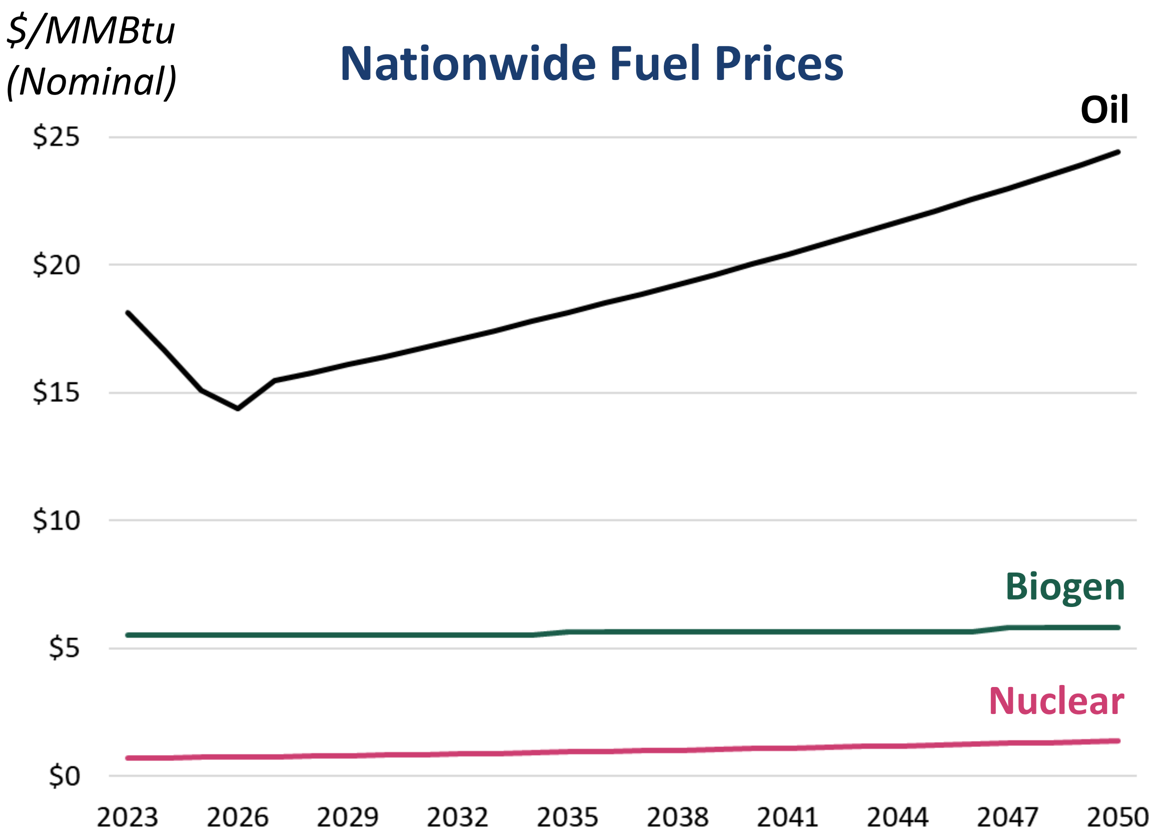
# Coal Prices

- Coal prices for internal and external zones vary by region.
- Modeled zones are mapped to coal price basins in SPP provided data consistent with ITP 2025 assumptions.
- Prices are adjusted using an annual inflation rate of 2.6%.
- Impacts of EPA Rule 111 are not modeled in FERNS.



# Other Fuel Prices

- Oil, nuclear, and biogen prices are nationwide, the same prices are used for all zones.
- Oil prices are from SPP provided ITP 2025 inputs.
- Nuclear relies on forecasted prices from ATB (2023).
- Biogen relies on forecasted prices from ATB (2023) which assumes:
  - Fuel costs are representative costs of woody biomass taken from the 2016 Billion Ton Report (DOE, 2016).
  - Regional variations will likely ultimately impact biomass feedstock costs, but these are not included in the 2023 ATB.
  - Assumes a plant size of 50 MW.
- All prices are adjusted using an annual inflation rate of 2.6%.



# Appendix 2

# Detailed FERNS Study Results

CONTENTS

# APPENDIX 2:
# Detailed FERNS Study Results

Brattle

# Scenario Overview

This Appendix 2 presents key outputs of all five FERNS scenarios. We highlight capacity expansion results from the FERNS **moderate electrification** and **high renewables** scenario (B2) as the example to explain detailed model outputs and to introduce all scenario insights.

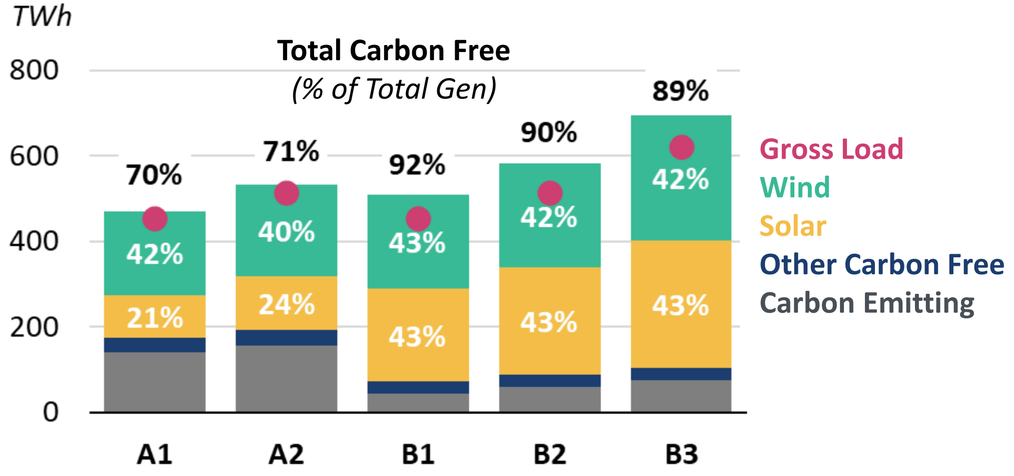
- We model three electrification load scenarios, consistent with the FERNS Demand Electrification Study completed by Evolved Energy Research.
  - Low, Moderate, and High electrification assumptions drive variations in SPP loads through 2050.
  - All electrification scenarios account for forecasted data center load.
  - No scenarios account for hydrogen electrolysis.
- We also model moderate (~70%) and high (~90%) penetrations of carbon free resources based on continuation of tax credits.
  - SPP is already at ~47% renewable today (the highest of all U.S. RTOs, exceeding even ERCOT and CAISO).

## FERNS Study Scenarios

| Electrification \ Carbon Free Resource Shares | Low | Moderate | High |
|---|---|---|---|
| **Low** | | A1 | B1 |
| **Moderate** | | A2 | **B2** (Example Scenario) |
| **High** | | | B3 |

*Source: FERNS scenario narrative*

## SPP-Wide Decarbonization Share by 2050




*Note: Total (%) shows % of total generation from carbon free resources*

# Key Findings from FERNS Simulations

In scenarios with high load growth and high shares of renewable generation, SPP is projected to **maintain resource adequacy in a cost-effective and affordable manner** if fossil-fuel generation capacity is retained (or replaced) for reliability purposes and sufficient new resources, including storage, are added to the SPP system.

A projected **$88–$263 billion of generation** investments will be needed to support SPP's load growth through 2050. This is possible **without significant rate increases (in inflation-adjusted terms)** due to load growth and fuel-cost savings, especially if federal tax credits (or similar renewable generation support) remain available.

Between **70% and 90% of SPP's annual energy is projected to be generated from renewable resources by 2050**, though conventional generation is expected to continue to serve a large share of SPP's resource adequacy needs, representing 40–60% of the region's accredited capacity. This is a function of technology costs, natural gas prices, and the availability of tax credits (or similar policies).

**Solar generation is projected to outcompete wind generation.** By 2050, 20–48 GW of new wind generation is expected to be added, which compares to 42–130 GW of new solar generation. As solar generation expands, 22–59 GW of battery storage is projected to be cost-effective (and often co-located) to maintain resource adequacy.

# Key Findings from FERNS Simulations

**4–21 GW of new regional transmission capacity** (between SPP zones) is projected to be cost-effective by 2050, necessary to support the delivery of generation to load centers.

Resource adequacy challenges evolve over time to be more frequent during: (a) winter months (particularly in high electrification futures) and (b) the early evening hours (after sunset). This implies that **winter planning reserve margins will need to be significantly higher than summer reserve margins,** due to low solar capacity values and high temperature-correlated fossil outages in the winter.

SPP has **sufficient available land to accommodate** the projected 60–180 GW of wind and solar generation capacity additions through 2050 in all scenarios evaluated.

The effective load carrying capability **(ELCC) value of solar and short-duration storage resources is projected to decline over time**, while the ELCC of wind resources increases slightly. Even the ELCC of 8-hour storage declines in the high renewable generation scenarios, indicating a need for long-duration storage. Interties with neighboring regions offer valuable resource adequacy and extreme-weather resilience benefits to the SPP footprint.

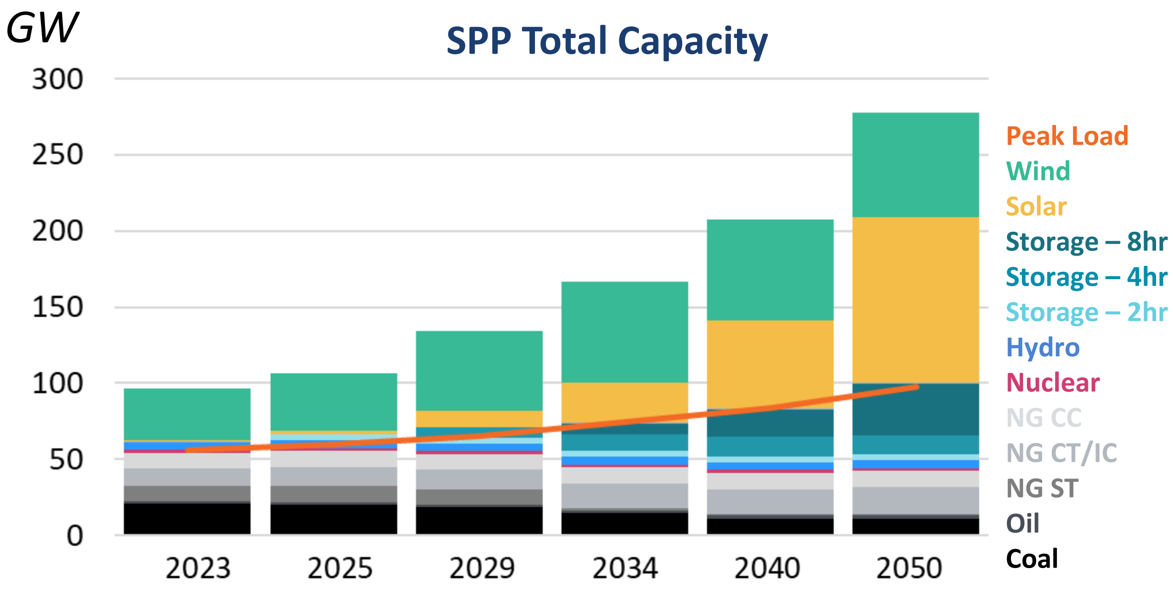
SPP is projected to become a **more significant net exporter by 2050**, particularly in the high renewable generation scenarios, due to the high-quality of renewable generation in the region.

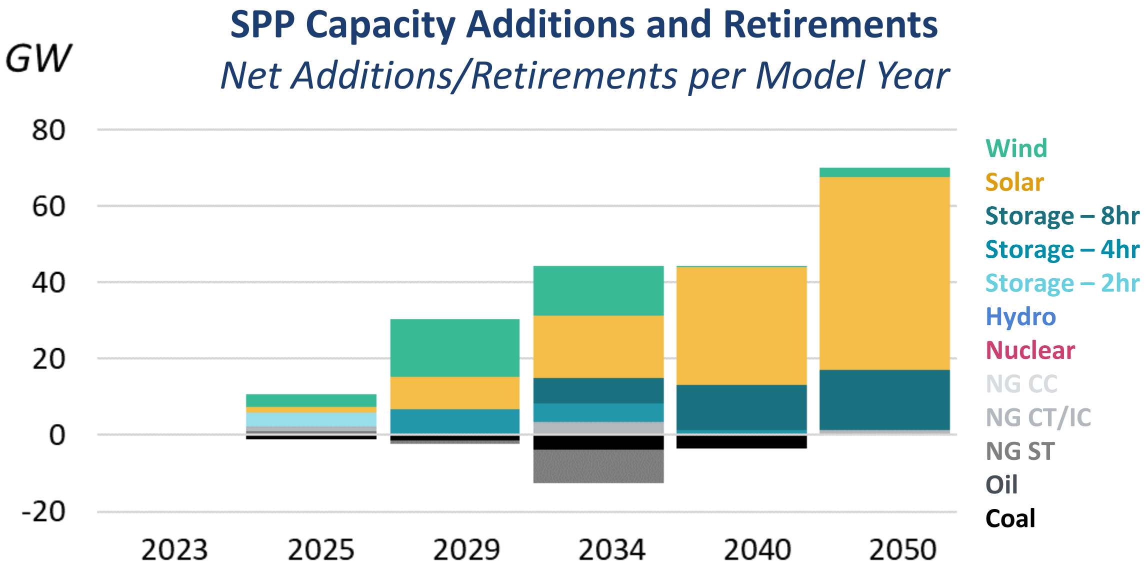
# SPP Capacity Additions over Time (Scenario B2)

In the moderate electrification and high decarbonization Scenario B2, SPP wide peak load increases from 55 GW to 97 GW (1.75x) by 2050, which requires significant resource deployments:

- **Through the 2020s:** Higher-cost fossil resources are retired and replaced with new wind, solar, and short duration storage (≤4hr)
- **In the 2030s:** Large quantities of renewables and storage are deployed to supplement additional fossil plant retirements. Fossil capacity is retained (at increasingly lower capacity factors, as shown on later slides) to support resource adequacy
- **In the 2040s:** Mid-duration (8hr) storage is added to meet resource adequacy needs. Wind deployment reaches saturation as solar increases through 2050 to meet growing demand

*Capacity additions are sensitive to resource cost assumptions. FERNS uses SPP's resource cost assumptions that are slightly lower for solar and higher for wind than other national projections, see Appendix 1 for more detail.*

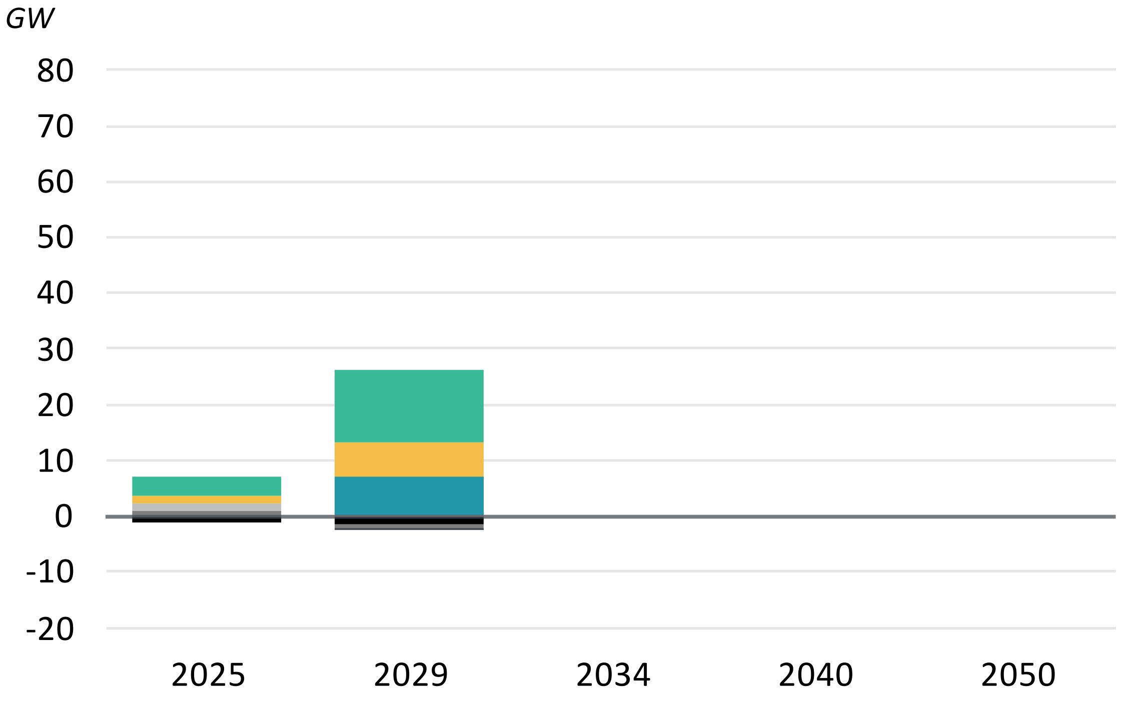


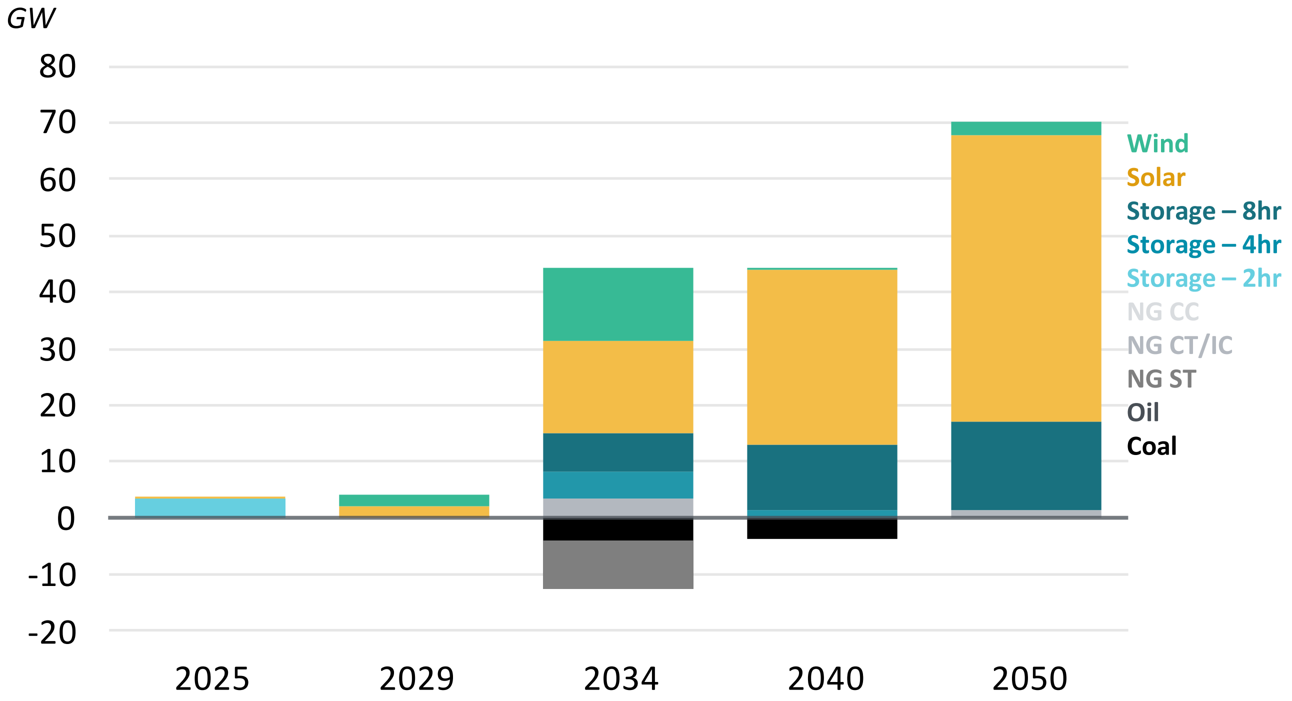
# Planned vs. Simulated Capacity Additions/Retirements (B2)

Up through 2029, we assume planned additions and retirements consistent with the draft 2025 ITP, in all scenarios. Starting in 2025, we allow additional new capacity to be built (and, by 2034, retired) by the model if the simulations show it is cost effective to do so.

**SPP Planned Additions and Retirements (GW)**
*Same for All Scenarios*




**Simulated SPP Economic Additions and Retirements (GW)**
*Moderate Electrification and High Renewables (Scenario B2)*



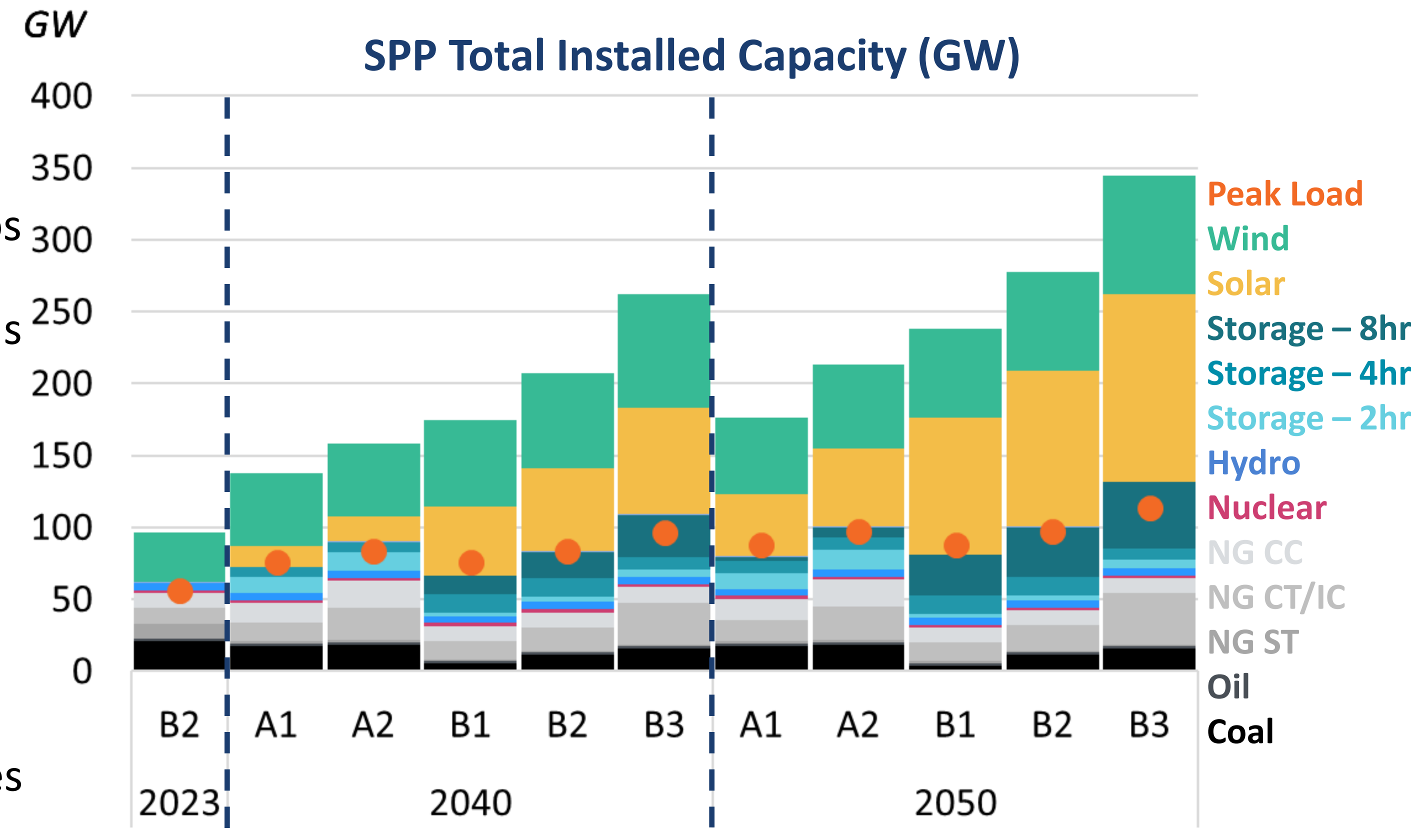

*Note: Additions are shown for each model year (i.e. cumulative additions between modeled years). GW values are not added in a single calendar year. NG = natural gas, CC = combined cycle, CT = combustion turbine, IC = internal combustion, ST = steam turbine. In following charts, all turbine types are categorized as "gas."*

# Capacity Buildout Across Scenarios

| Electrification \ Carbon Free Resource Shares | Moderate | High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

The extent to which SPP will electrify and decarbonize will lead to different optimal resource solutions as shown through scenario analysis:

- **Through the 2020s:** In the near term, all scenarios have comparable capacity buildout driven by already scheduled retirements and planned builds currently in the interconnection queue
- **In the 2030s:** High decarbonization scenarios replace fossil capacity with low-cost renewables and storage resources, with more resources needed for higher electrification scenarios
- **In the 2040s:** Longer duration storage becomes a key resource adequacy asset for the high decarbonization scenarios paired with renewables (primarily solar). Moderate decarbonization scenarios rely on more fossil, shorter duration storage assets, and much less solar by 2050

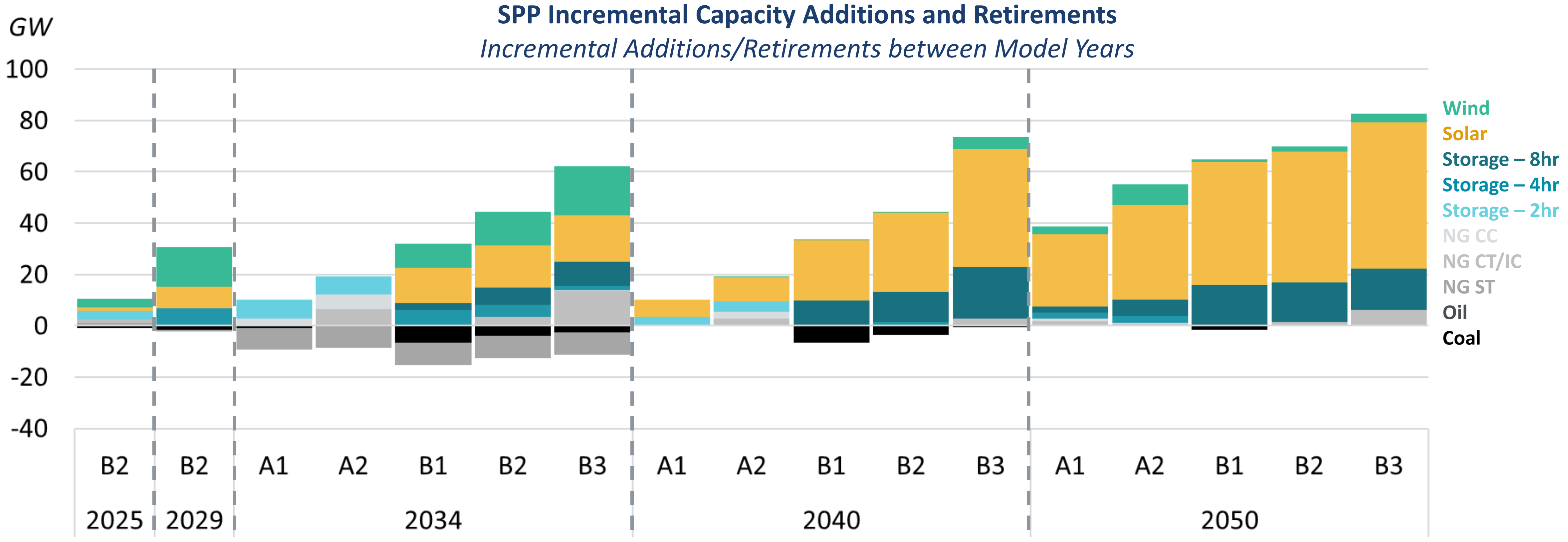



*Note: Only select later years, 2040 and 2050, are highlighted in this chart. For full capacity buildout by year see detailed tables later in the appendix.*

# Incremental Capacity Additions Across Scenarios

| | Carbon Free Resource Shares | |
|---|---|---|
| Electrification | Moderate | High |
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

In all scenarios, wind, short duration storage, and some solar are the most cost-effective near-term additions. In the 2030s, the moderate carbon-free scenarios (A1, A2) retain fossil and add limited amounts of solar with some short duration storage. The high carbon-free, "B", scenarios project a different future with longer duration storage and large solar additions.



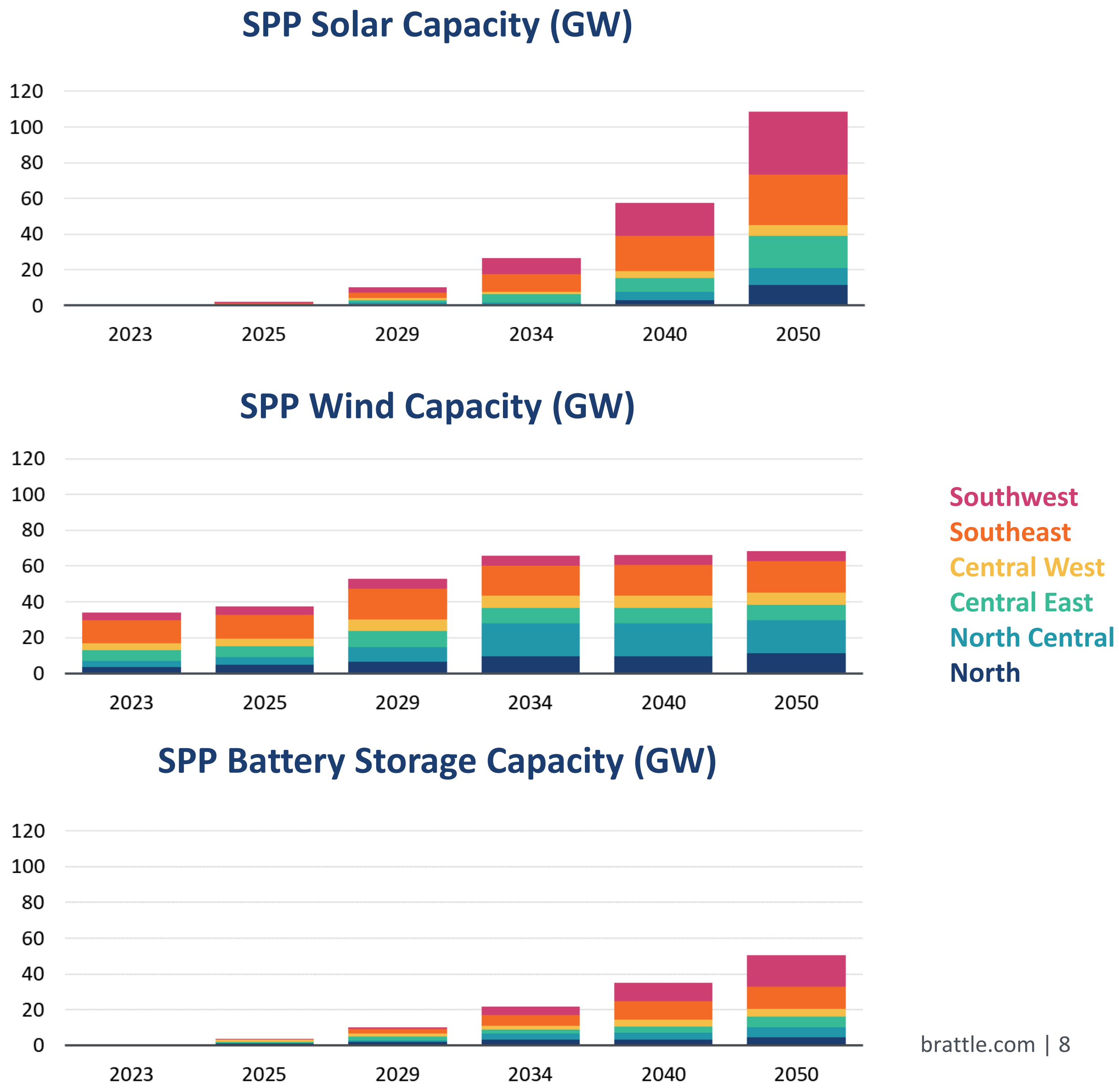

*Note: Additions are shown for each model year (i.e. cumulative additions between modeled years). GW values are not added in a single calendar year. NG = natural gas, CC = combined cycle, CT = combustion turbine, IC = internal combustion, ST = steam turbine. In following charts, all turbine types are categorized as "gas."*

# Zonal Capacity Results: Cumulative Installed Generation (Scen. B2)

In the moderate electrification and high decarbonization scenario (B2), SPP will continue to deploy wind in the near term before deploying mostly high-quality solar resources through 2050:

- **Through the 2020s:** Wind is the primary resource added in the next decade, with most new resources developed in the Southeast (to serve high loads), Central East, and North Central
- **In the 2030s:** Wind additions taper off while solar and storage development increases, primarily in the Southern and Central zones (including the eastern SPP zones with high loads)
- **In the 2040s:** Solar is the primary renewable resource added, paired with storage additions roughly distributed through the Southeast, Southwest, and Central East—all zones with high quality resources

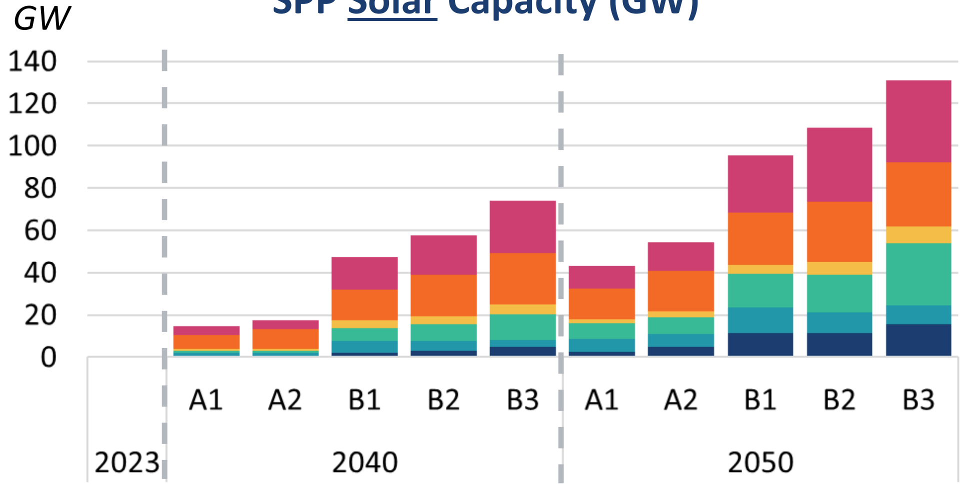
Charts reflect cumulative (including existing) capacity by select resource type and zone. See next slide for comparison across all scenarios.



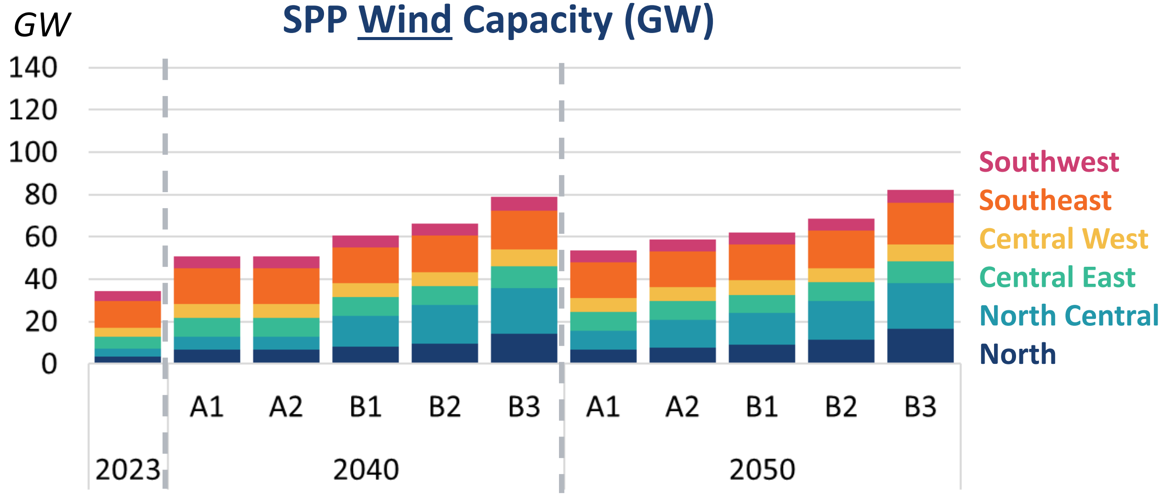
# Zonal Renewable and Storage Capacity by Scenario

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

## SPP Solar Capacity (GW)

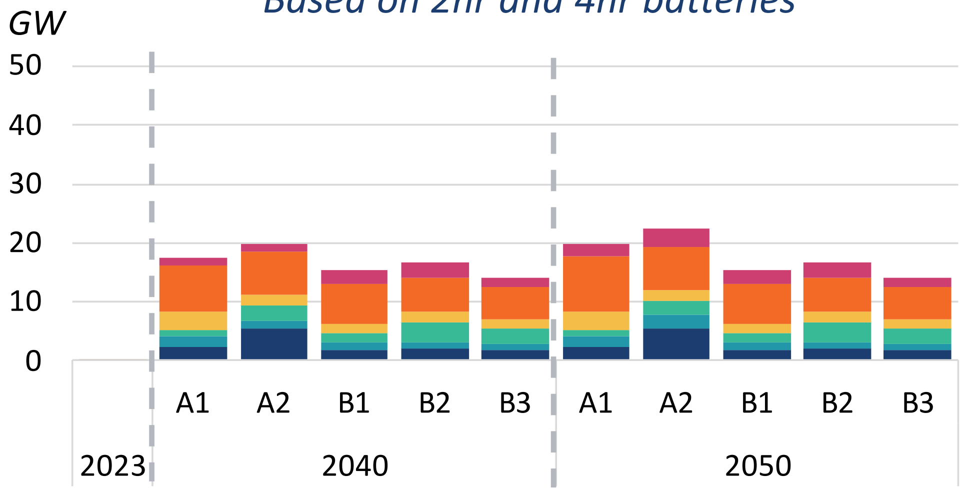



## SPP Wind Capacity (GW)



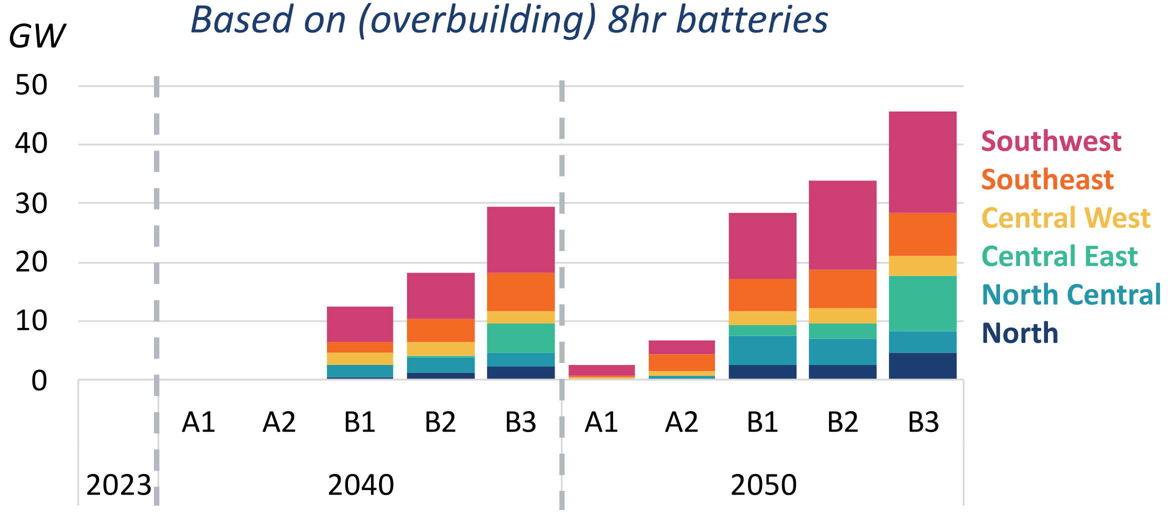

## SPP Short-Duration Battery Storage Capacity (GW)

*Based on 2hr and 4hr batteries*




## SPP Longer-Duration Storage Capacity (GW)

*Based on (overbuilding) 8hr batteries*




*See full resource detail in the Appendix.*

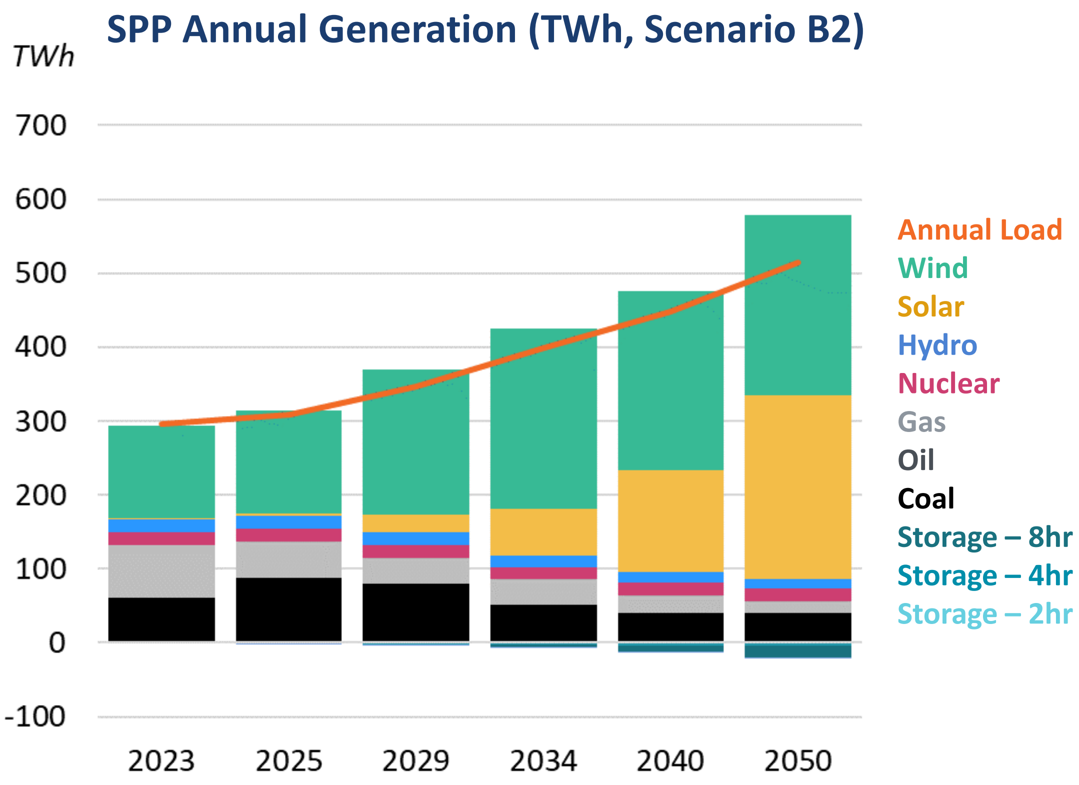
*Note: Y-axes differ across resource types.*

# SPP Annual Generation Output (Scenario B2)

In the moderate electrification and high decarbonization scenario (B2), SPP reaches ~90% renewable (and 93% clean) by 2050. SPP annual energy demand is expected to increase from 300 TWh to 515 TWh (1.7x) by 2050:

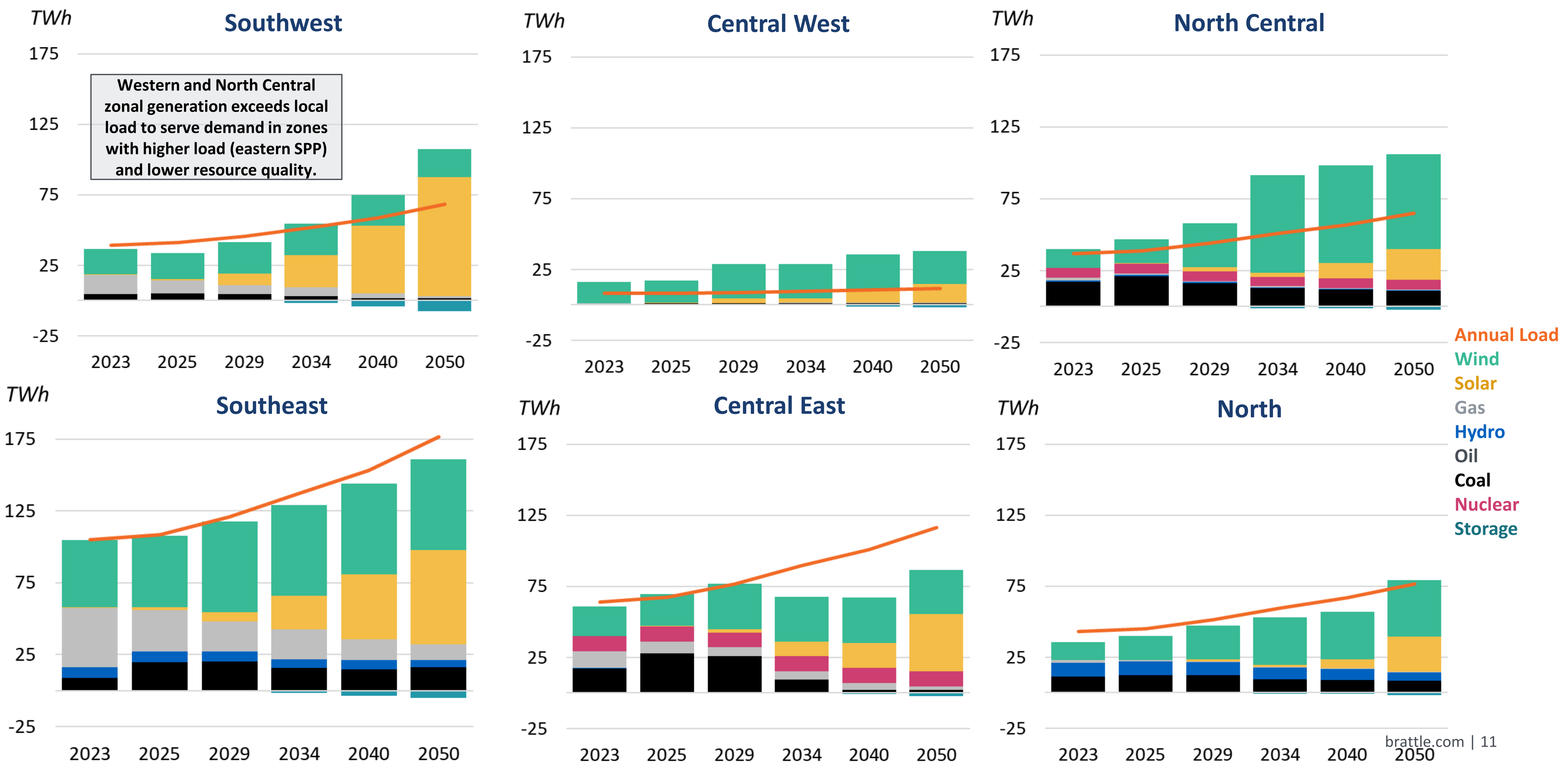
- **Through the 2020s:** SPP serves increasing load with additional wind and some new solar, which starts to displace higher variable cost thermal generation
- **In the 2030s:** SPP experiences more significant load growth between 2029 and 2040. Most of the new demand is met by renewables. Higher-cost fossil plants are used less frequently, with their output replaced by renewable generation
- **In the 2040s:** Electrification continues to accelerate load growth through 2050, which is almost exclusively served by new solar resources

Today, SPP is currently at ~40% renewable generation, despite few state and industry driven goals. Through 2050, SPP will continue to serve much of its annual demand with renewables due to high-capacity factors and low costs (particularly with continued availability of federal tax credits through 2050).




*Note: Total SPP generation exceeds annual load in years when SPP is a slight net exporter to neighboring regions. This occurs in later years when SPP has high renewable saturation in the B2 scenario.*

# Zonal SPP Generation Output (Scenario B2)



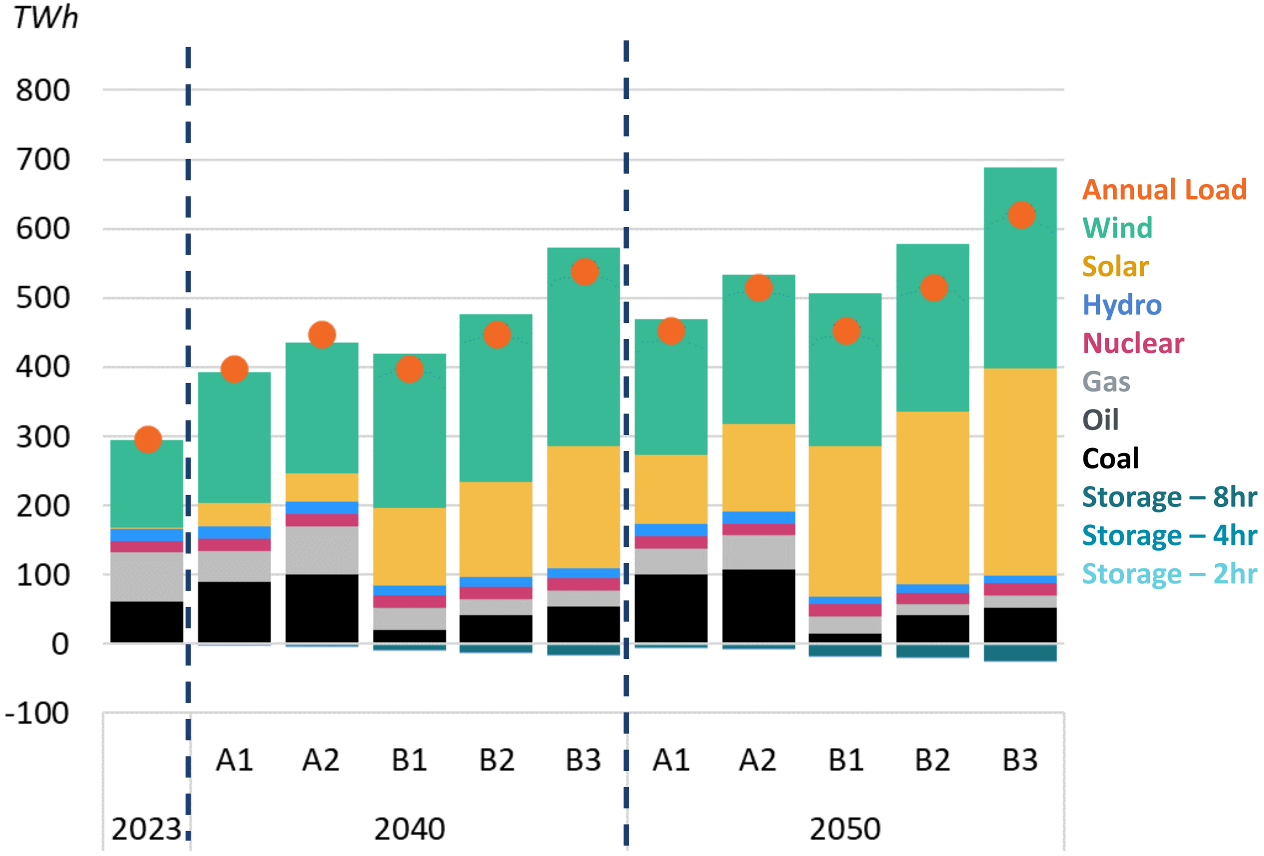
# Generation Output Across Scenarios

| Electrification | | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|---|
| | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

Electrification and decarbonization scenarios lead to different optimal use of the generation fleet:

- **Through the 2020s:** In the near term, all scenarios have comparable buildout with less generation in lower electrification scenarios
- **In the 2030s:** By the 2030's, high decarbonization scenarios deploy mostly new solar resources in SPP, while moderate decarbonization buildout continues to rely more heavily on fossil resources to meet electrification load
- **In the 2040s:** High decarbonization scenarios continue to deploy renewables for local demand and for cost-effective exports to neighboring regions. High decarb scenarios result in ~90% carbon-free while moderate decarbonization results in ~70% carbon-free generation by 2050

**SPP Annual Energy Generated (TWh)**




*Note: Total SPP generation exceeds annual load in years when SPP is a slight net exporter to neighboring regions. This occurs in later years when SPP is highly renewable saturated.*

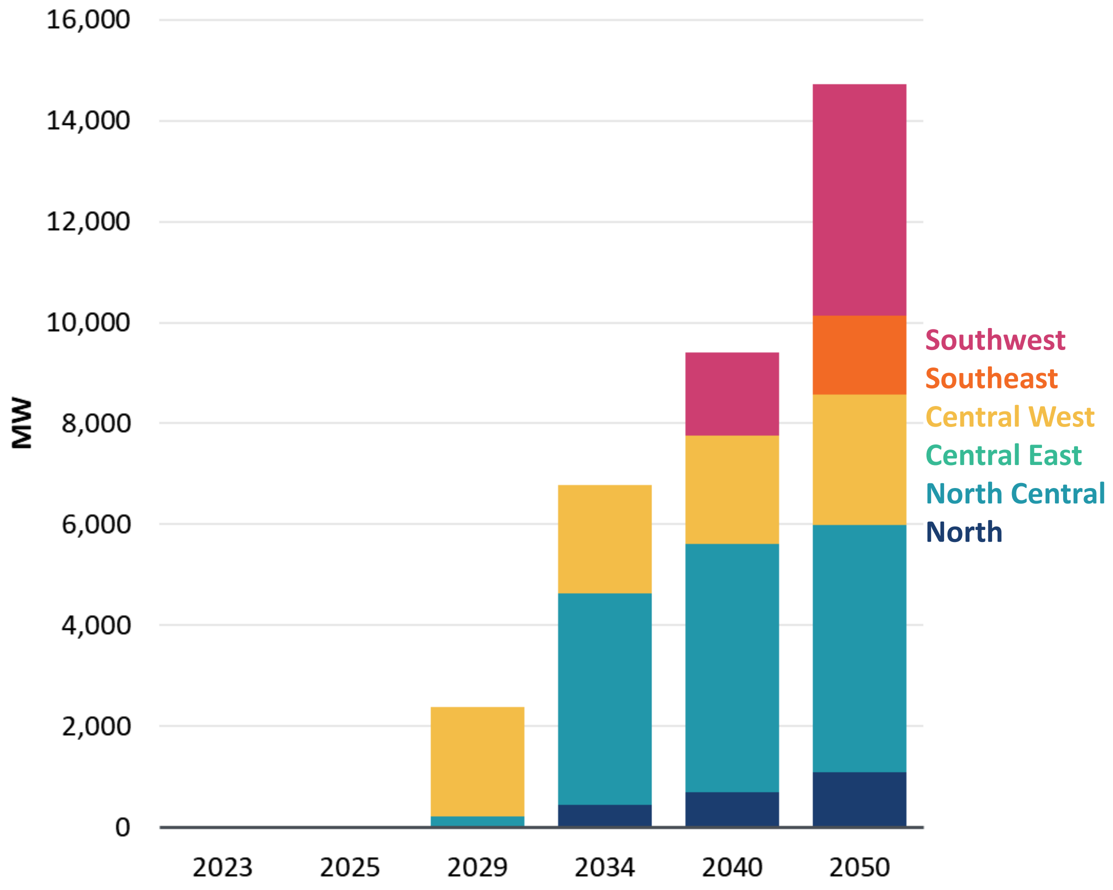
# Interzonal Transmission Expansion (Scenario B2)

To meet future SPP resource adequacy needs, resources can locate within demand zones or in nearby SPP zones if sufficient transmission capacity exists or is invested in:

- **Through the 2020s:** Very limited "economic" expansion of the interzonal interfaces occurs before 2030. Existing interface flows are adequate for near-term needs. Economic expansion of interzonal interfaces is not allowed until 2029
- **In the 2030s:** Economic transmission expansion increases Central West and North Central import/export capability, where solar and wind resources are deployed
- **In the 2040s:** Additional import/export capability is economically added to serve the North, Southeast, and Southwest zones, primarily to increase flows to and from solar rich regions

*Note: Zone-internal transmission is modeled as a generator-interconnection cost adder. See Appendix 1 for more detail.*

**SPP Cumulative Economic Interzonal Transmission Expansion**
*(MW of added zonal import/export capability, Scenario B2)*



# Interzonal SPP Transmission Expansion by Scenario

| Carbon Free Resource Shares | | |
|---|---|---|
| Electrification | Moderate | High |
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

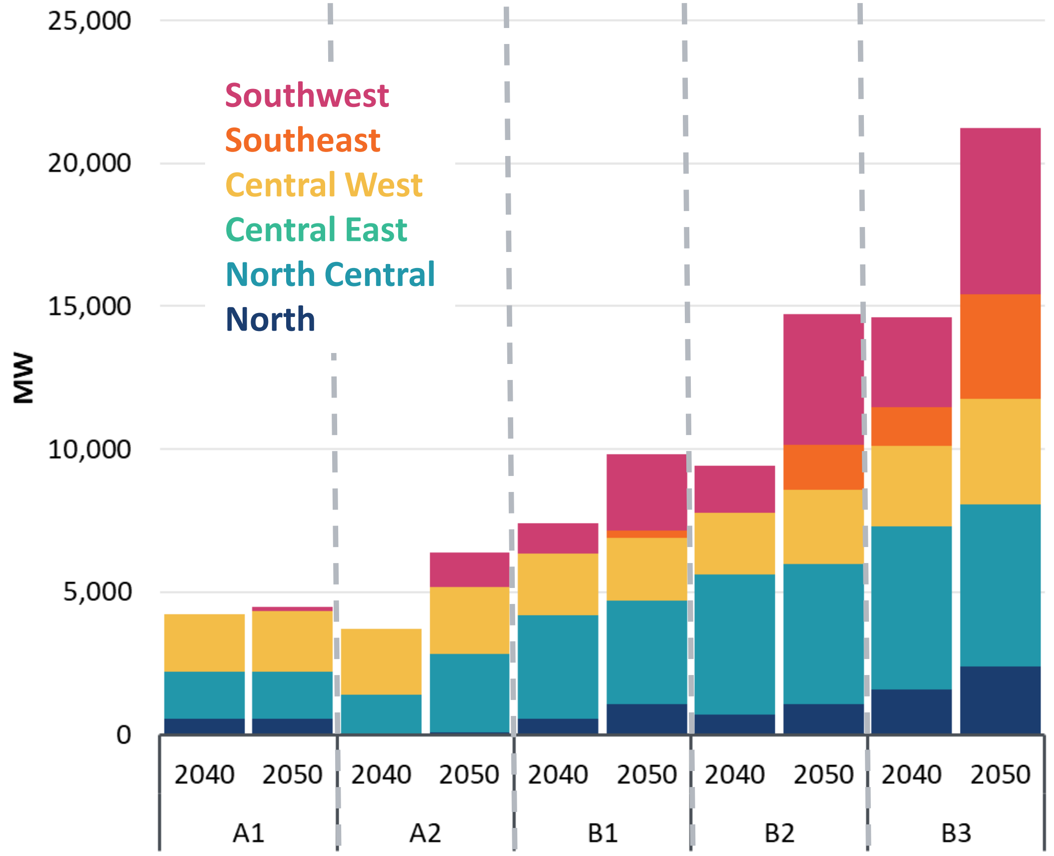
The need for additional SPP interzonal transmission (relative to assumed import/export limits of LOLE zones) varies significantly with electrification and decarbonization trajectories:

- Moderate carbon-free scenarios (A1, A2) result in the lowest demand for additional interzonal transmission because load is met by local dispatchable fossil generators
- In high decarbonization scenarios (B1, B2, B2), it is more cost effective to locate (the lower-cost) renewables in high resource-quality regions (Southern and Central zones) and invest in transmission infrastructure when renewables are not zonally located with load.
- Although carbon-free share drives differences in transmission investments, higher electrification leads to increased transmission builds in order to accommodate increased SPP wide demand and additional generation needed to serve load
- The optimal level of transmission expansion is a function of both transmission costs and generation costs

A portion of these expansion levels will be addressed by SPP's 2024 ITP proposed transmission investments, which total $7.7 billion. FERNS modeling was completed before ITP 2024 release.

**SPP Cumulative Economic Interzonal Incremental Transmission**

*(MW of added zonal import/export capability by 2050)*



# Interzonal Transmission Flows (Scenario B2)

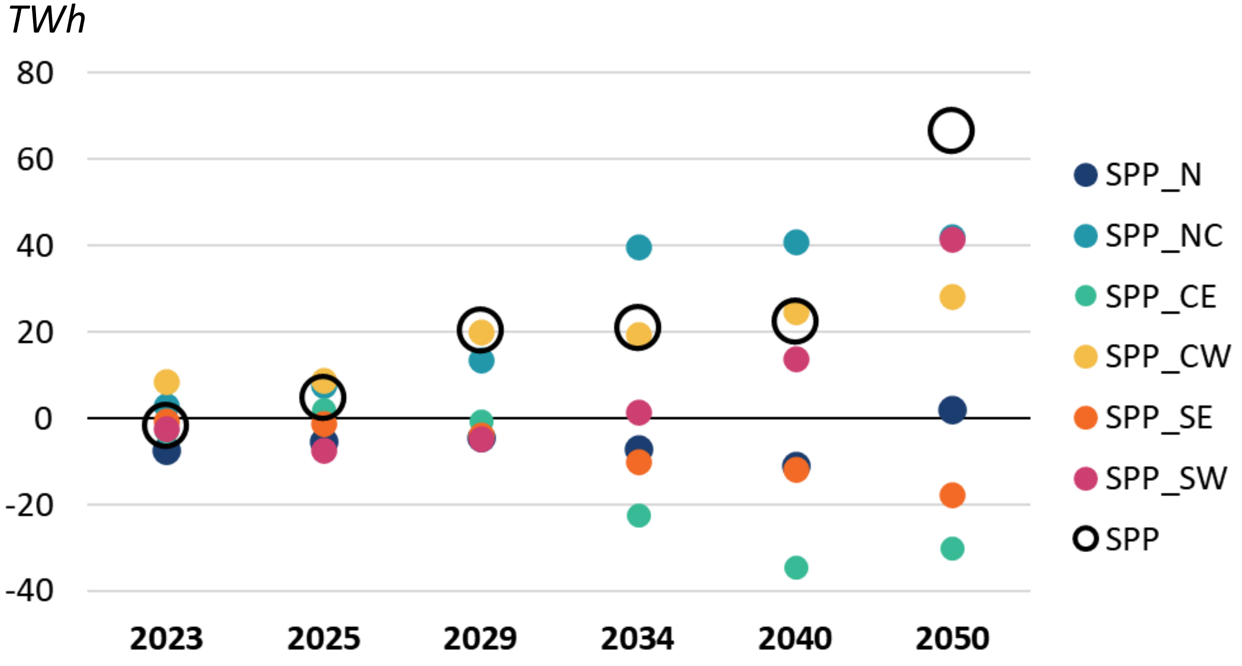
SPP satisfies its internal demand with local generation, flows between SPP regions, and external neighboring zones:

- **Through the 2020s:** SPP is a slight net exporter and mostly relies on generation located in the same load zone. The Central West zone has relatively low load and exports excess wind generation to other SPP zones
- **In the 2030s:** Load growth accelerates in the eastern portion of SPP and relies on generation from wind assets in the NC and CW zones
- **In the 2040s:** As electrification continues across SPP, load growth in the SE and CE zones is increasingly served by solar and wind generation exports from the western zones

The next slide presents the flow duration curves for each internal SPP interface and model year.

**SPP Annual Internal Interface Flows**

*(Positive = zonal exports)*

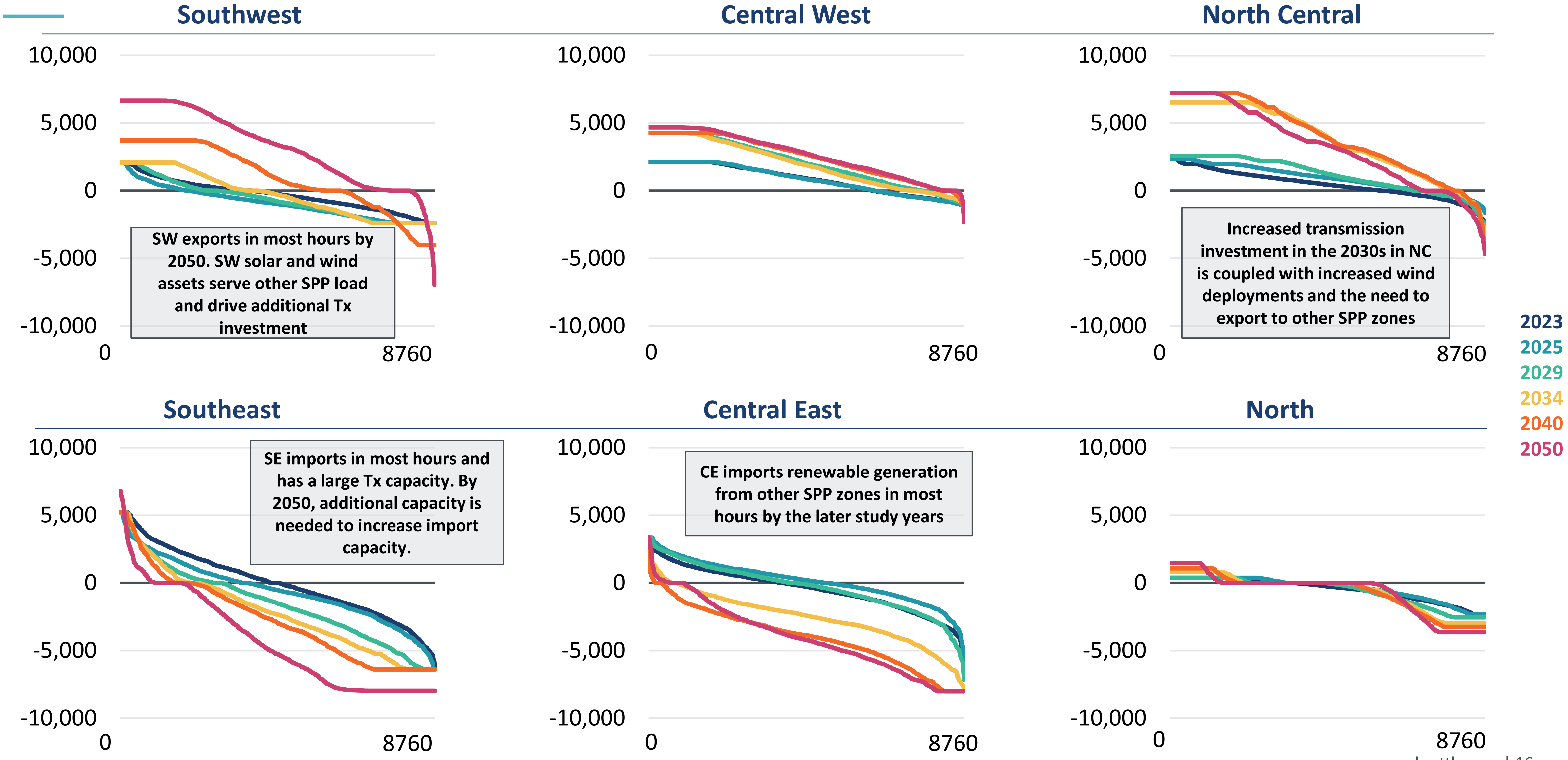



*Note: Chart shows annual net interface flows (TWh) across the internal SPP interfaces. For example, in 2023 Central West had net 8.5 TWh exports to other SPP zones.*

APPENDIX 2: TRANSMISSION

# Zonal Interface Duration Curve (Scenario B2)

*Hourly MW Internal Flows (Positive = Zonal Export)*



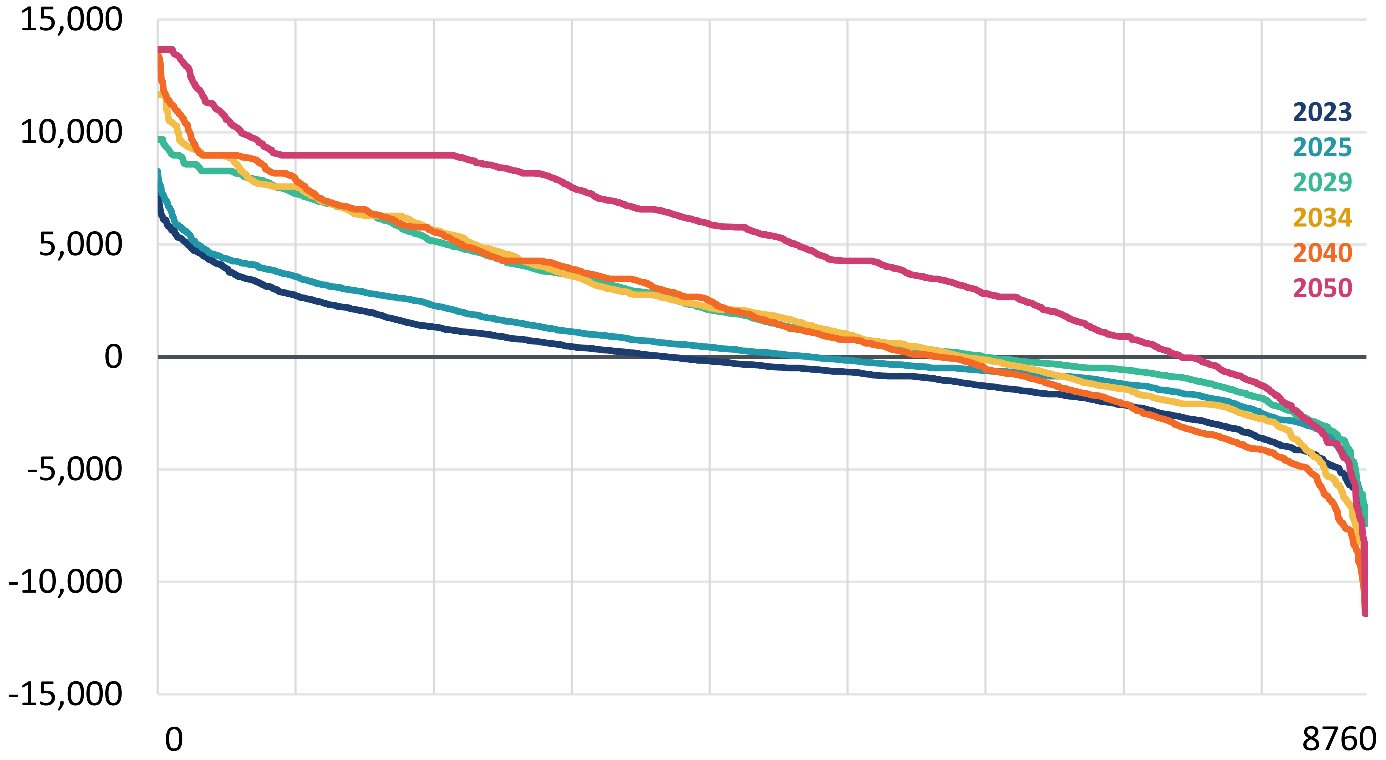
# Reliance on Neighboring Regions (Scenario B2)

SPP has transfer capability with all neighboring regions, with large connections to MISO and the West

- **Through the 2020s:** SPP is a slight net exporter, exporting from other regions in just over half the hours throughout the year
- **In the 2030s:** Through the 2030's as SPP continues to deploy solar and wind resources, SPP begins to export more generation to neighboring regions
- **In the 2040s:** By 2050, SPP exports in most hours throughout the year as neighboring regions import low-cost renewables

We do not model economic expansion of external interfaces, which are the same across all scenarios.

**SPP Net Imports and Exports across all interties (MW)**
*(Positive = net flow out of SPP; Negative = net flow into SPP)*



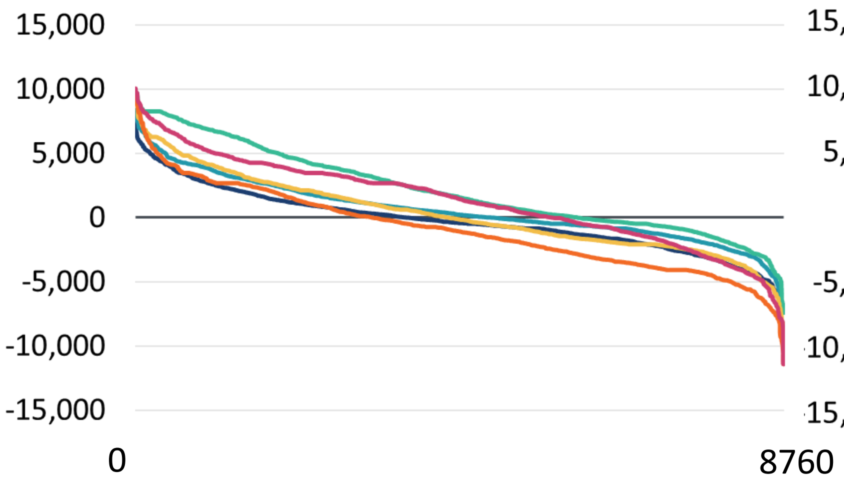

*Note: Net imports shown across interfaces between SPP and all neighboring regions*

# SPP Interface Duration Curve across all Scenarios

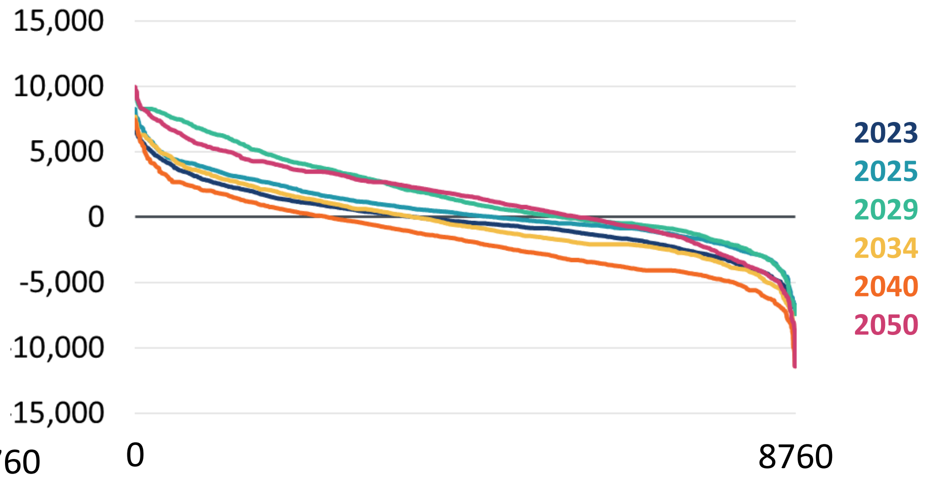
*Hourly MW Internal Flows (Positive = net flow out of SPP; Negative = net flow into SPP)*

| Electrification \ Carbon Free Resource Shares | Moderate | High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

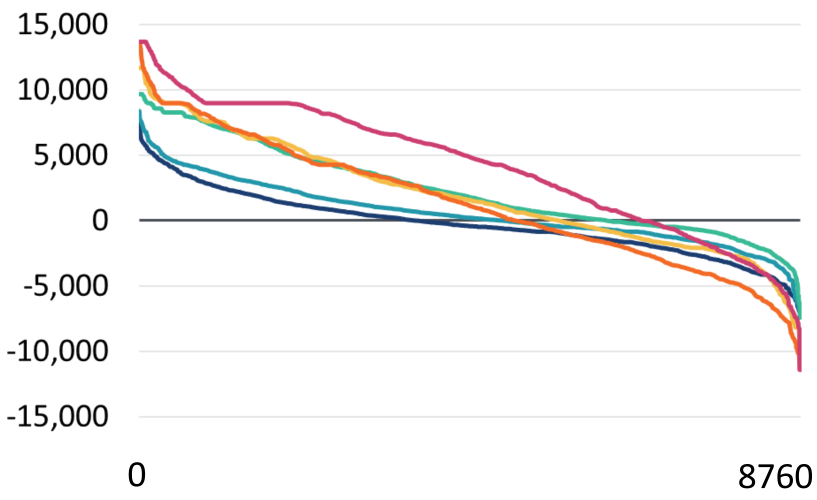
## Scenario A1



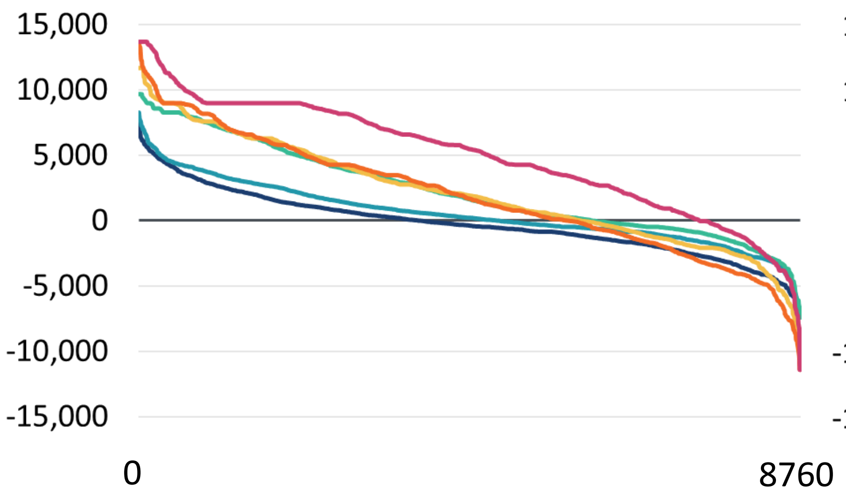

## Scenario A2



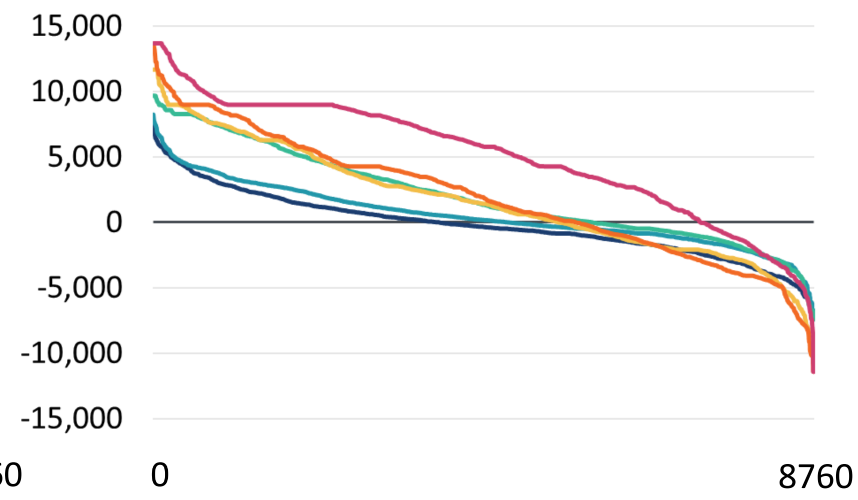

## Scenario B1




## Scenario B2

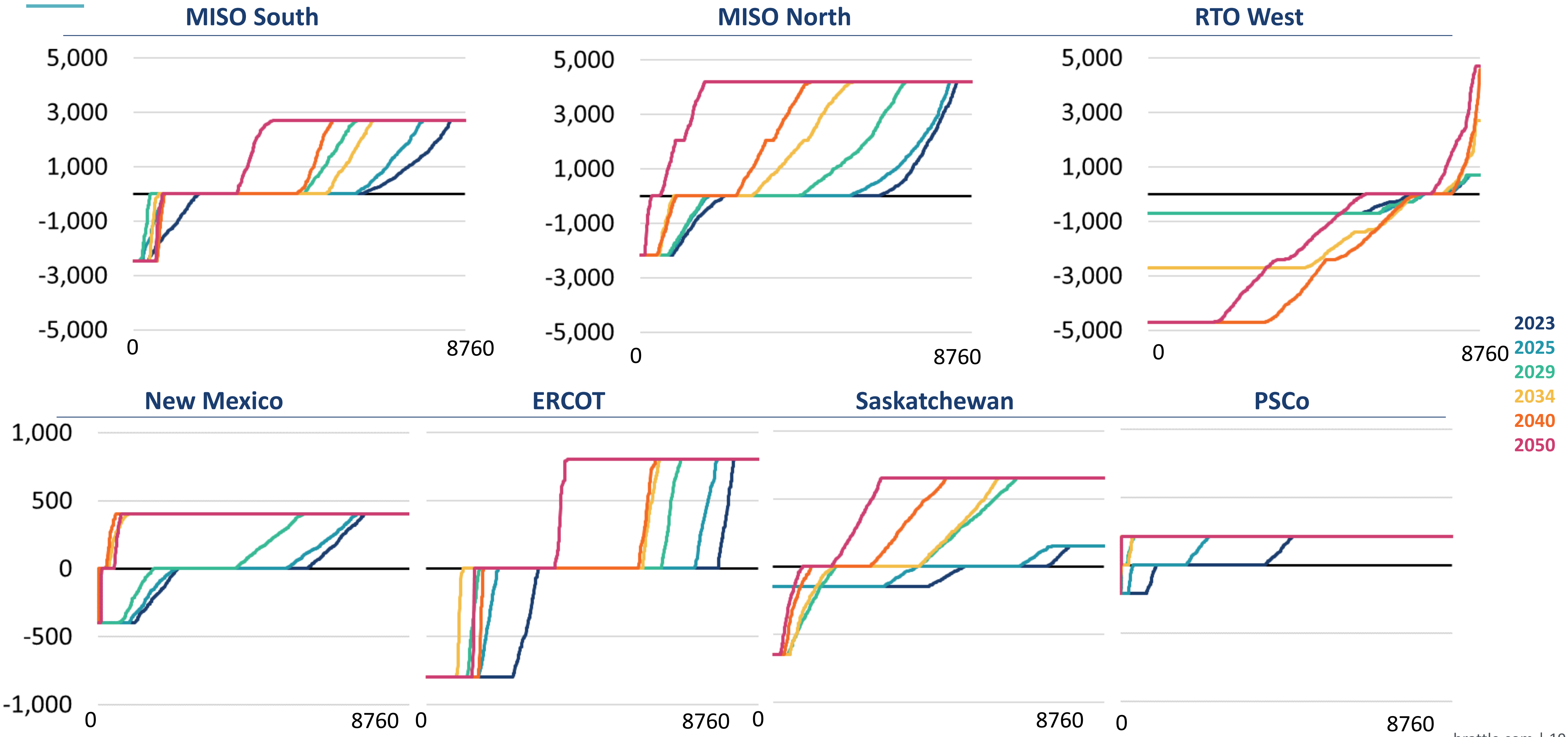



## Scenario B3



# Interface Flow Duration Curve by Neighbor (Scenario B2)

*Hourly MW External Flows (Positive = net flow out of SPP; Negative = net flow into SPP)*



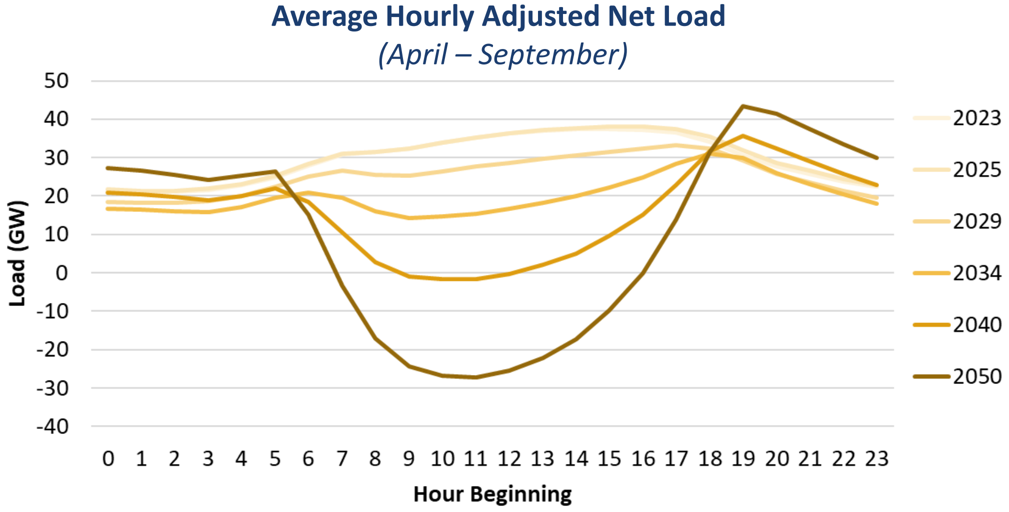

*Note: Scale of vertical axis differ across figures.*

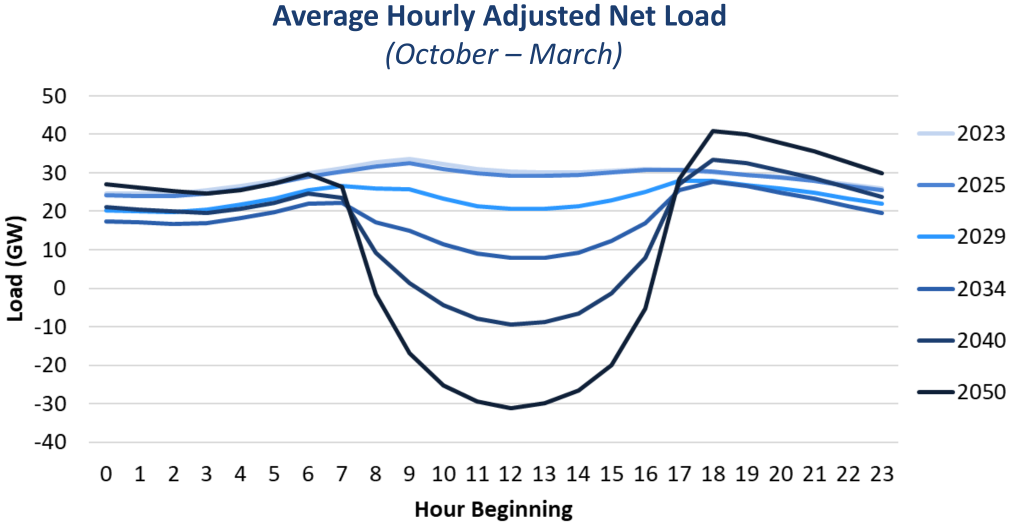
# Future "Net Load" Conditions (Scenario B2)

SPP system conditions will evolve with increased electrification and renewable penetration. At right are the proxy year SPP-wide net load shapes (adjusted for fossil outages) for scenario B2, shown as daily (24 hour) averages for two 6-month seasons:

- **Through the 2020's:** Net peak-load hours are concentrated in the early afternoon and the net load shape is relatively flat throughout the day
- **In the 2030's:** Additional renewable resource penetration (primarily solar) begins to shift the net peak hours later in the day and create more variation in daily load shape
- **In the 2040s:** Solar becomes the primary resource added to the system, which serves net load during midday hours and shifts the net peak to late evening. Additionally, the net peak hours are concentrated in a few hours of the day (6-8pm) compared to the flat need for resource adequacy from ~noon to 5pm in early years

Storage and firm generation (or load management) will be needed to serve the hourly net load conditions in later years.



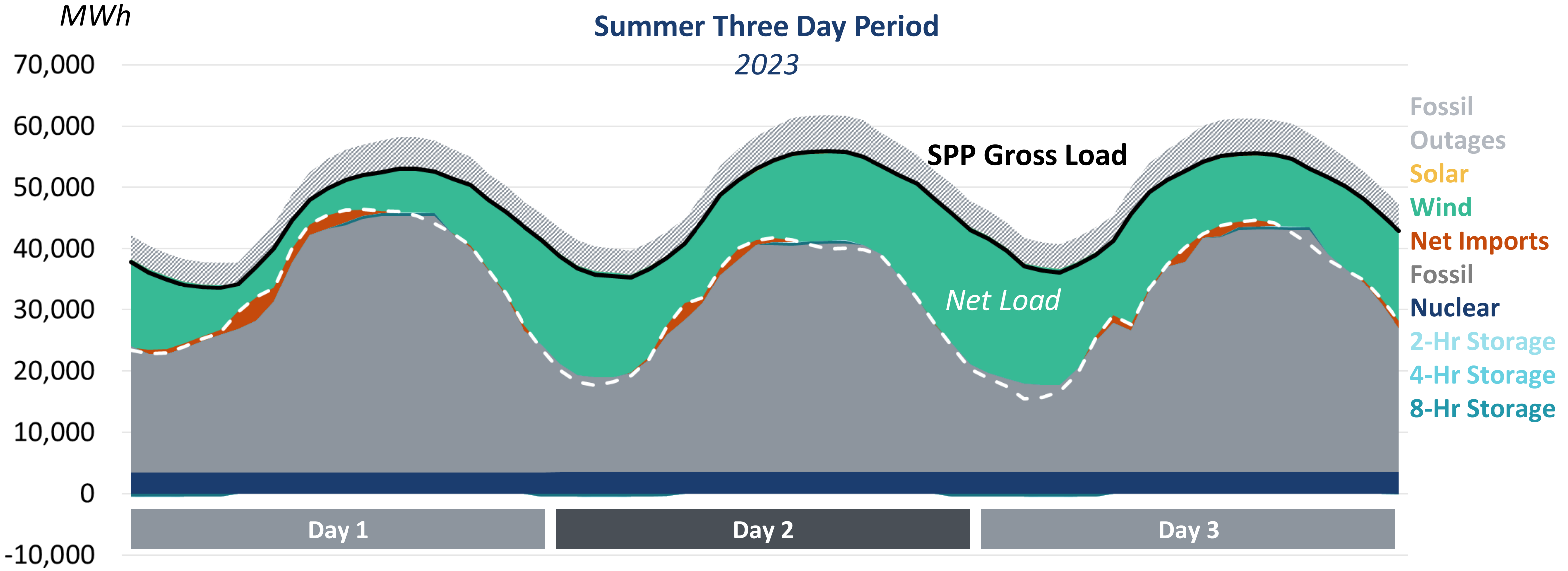



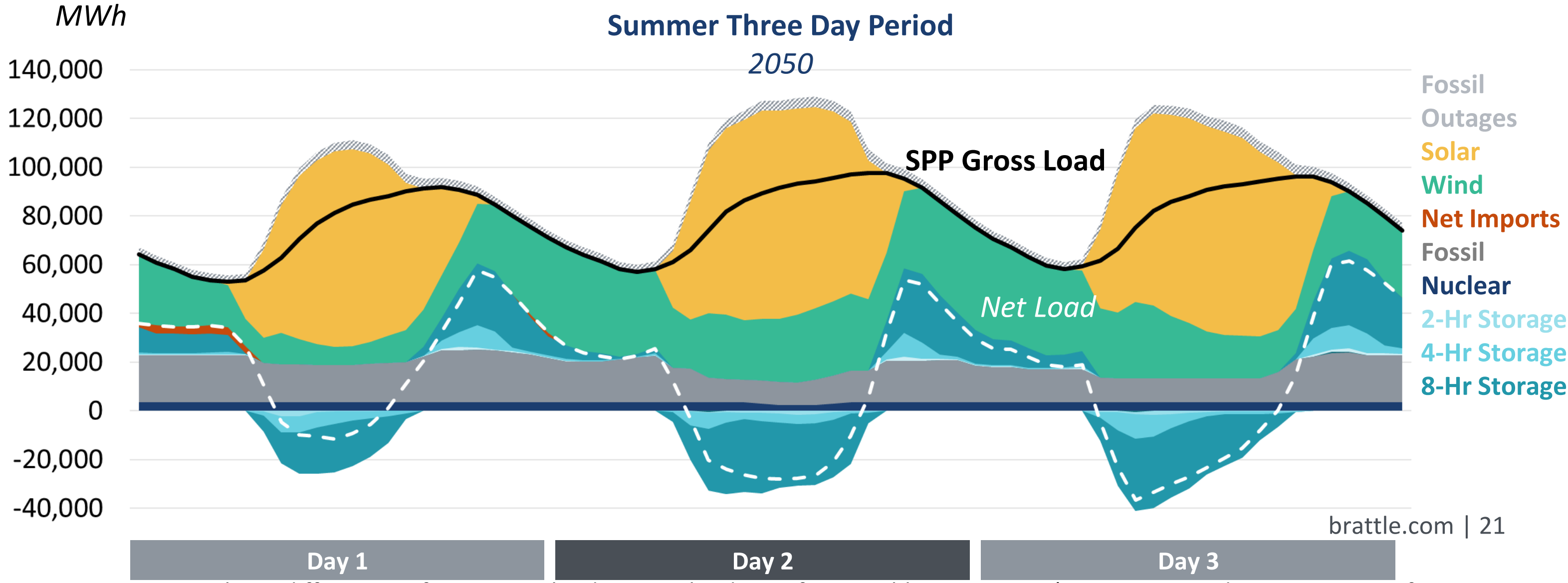

*Note: Results show average 24-hour seasonal shapes of system gross load minus variable renewable generation (solar, wind) plus fossil outages, without any battery storage impacts. Results show the B2 scenario with medium electrification and high carbon-free resource share reaching ~90% by 2050.*

# SPP Hourly Operations Over 3 Summer Days: 2023 vs. 2050 (B2)

As SPP decarbonizes, fossil operations are displaced by renewables and mid-duration storage:

- Solar increases penetration and "duck curve" net load shape
- Longer duration storage enters in later years to charge during high solar hours and serve load during low renewable output periods (e.g., overnight)
- Coal continues operations as a base load generation, but could be displaced by gas depending on price dynamics




*Note: Vertical axis differ across figures. Net load is gross load net of renewable generation (not storage and not accounting for fossil outages because they are shown individually in the chart.*

# Available Capacity During 100 Tightest Hours

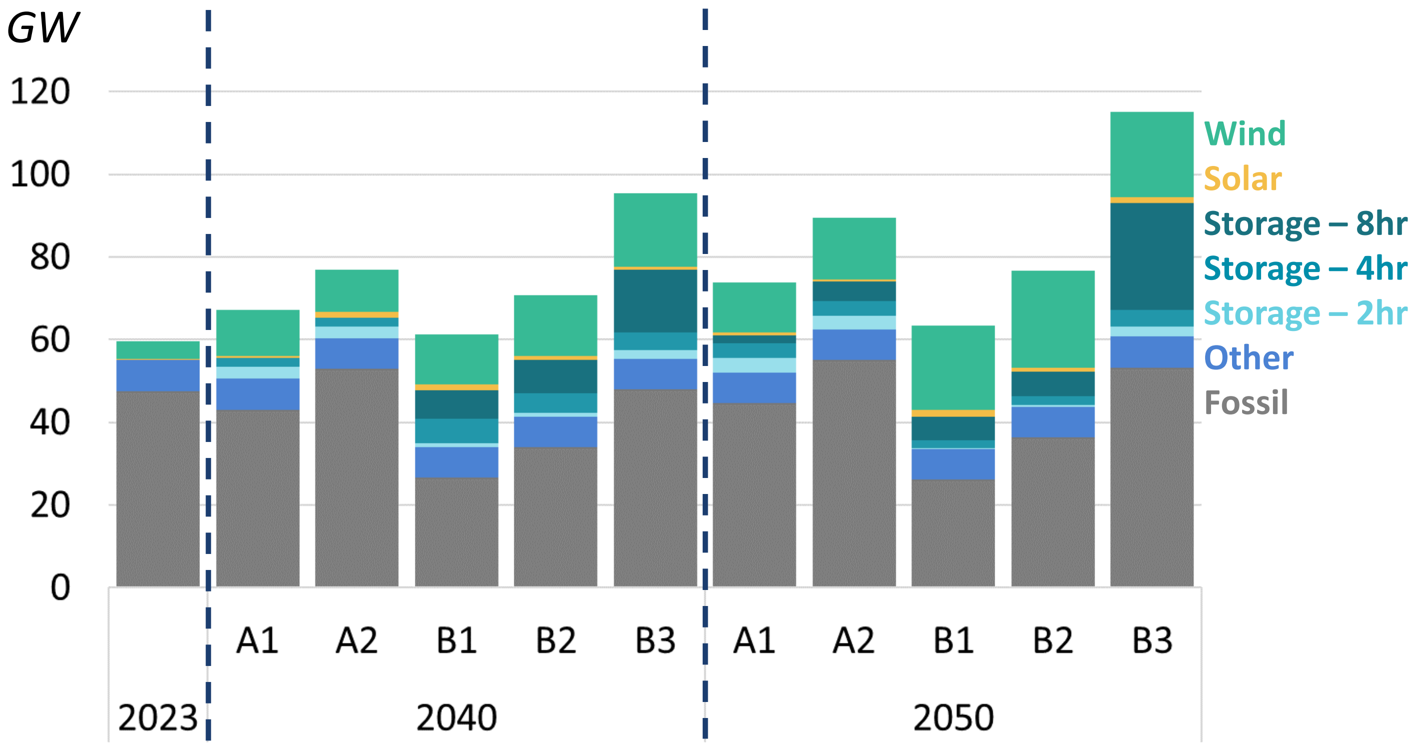
| | | Carbon Free Resource Shares | |
|---|---|---|---|
| | | Moderate | High |
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

Across all scenarios, SPP will continue to rely on fossil resources during challenging system hours. The chart shows the available resource capacity during the top 100 RA risk hours:

- **Today in the 2020's:** SPP primarily serves load during risk hours (high summer load and winter risk days) with thermal resources, supplemented by low quantities of wind and nuclear generation
- **Through 2040:** While fossil continues to dominate, wind resources increase their contributions in peak hours across all scenarios, with high renewable B scenarios also relying on battery storage
- **By 2050:** Fossil resources still contribute to 41% to 62% of rated capacity in RA risk hours, even in scenarios with 90% clean energy generation

See later slides for resource specific proxy ELCC values.

**SPP Available Capacity During 100 Highest RA-Risk Hours (GW)**



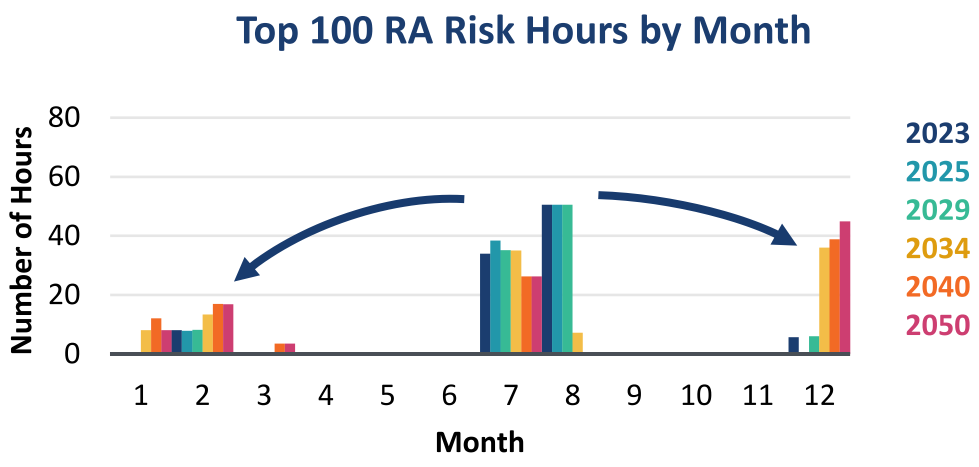

*Note: Only select later years, 2040 and 2050, are highlighted in this chart.*

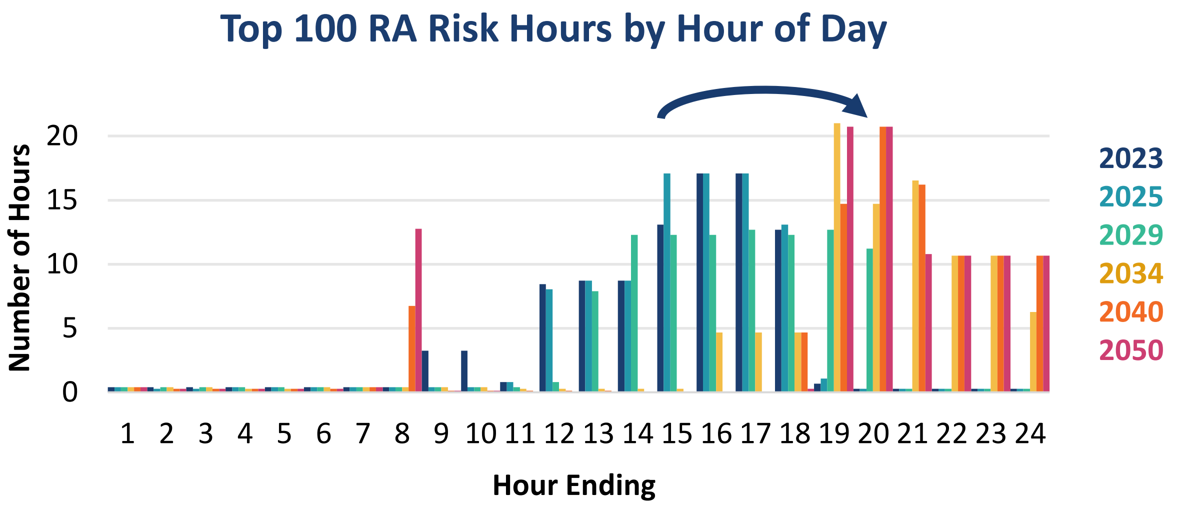
# SPP Resource Adequacy Needs and Challenges (Scenario B2)

Simulations show SPP resource adequacy challenges evolve over time as the system electrifies and decarbonizes, reflecting changing net loads:

- **Through the 2020s:** Resource adequacy risk continues to be primarily concentrated during early summer afternoons and during (infrequent) severe winter cold-snaps
- **In the 2030s:** Net load conditions (high solar generation) shift resource adequacy risk to later evening hours and increased frequency of RA challenges during winter months
- **In the 2040s:** Tight resource adequacy hours become significantly more frequent in winter months, during mornings and late evenings (even outside of severe winter storm periods)

Charts show the top 100 hours with highest resource adequacy risk in each year (defined as hours with the lowest "supply cushion") and reveal when tight conditions could occur.



# RA Violations / Potential Load-Shed Events

The FERNS modeling effort simulates weather-reflective resource adequacy challenges on an hourly basis. It uses a high "resource adequacy violations charge" to ensure that the frequency of operating reserve depletions or load shed events roughly meets the 1-in-10-year LOLE resource adequacy standard:

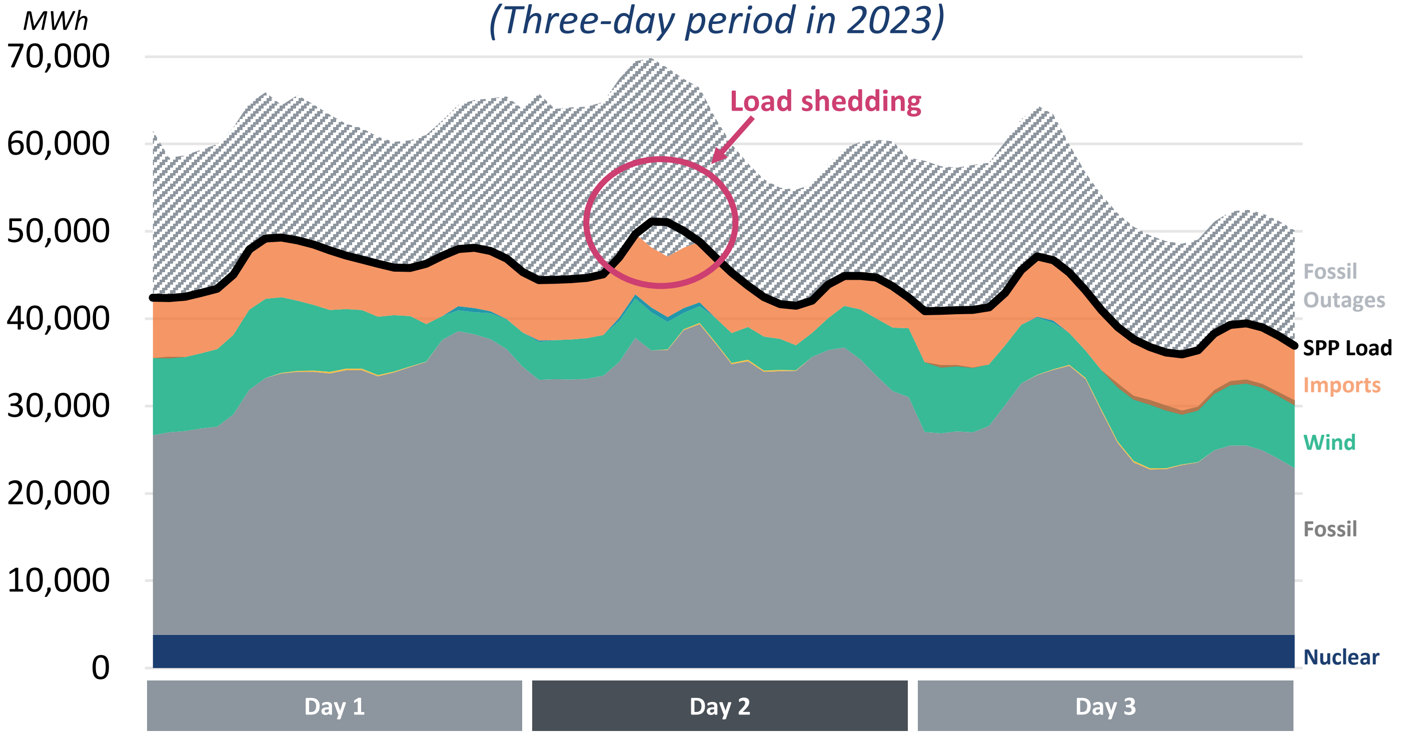
- The simulations use a $50,000/MWh RA violation charge to represent tradeoffs between adding generation capacity or allowing for load shedding (or operating reserve depletion) during the most challenging hours across all simulated weather years
- The RA violation charge needs to exceed typical estimates of the Value of Lost Load (VOLL) because the 1-in-10-year RA standard is more stringent than what could be justified economically with VOLL

The highest RA risks occur during the three-day cold-snap period (representing Uri-like severe winter storms, assumed to occur once every 5-10 years):

- RA violations (between none and 8,900 MW as shown in the table) occur only during the winter storm periods
- Other than in 2023, these violation of SPP RA criteria are not associated with load shed events due to energy imports available from neighboring regions (who do not experience the severe challenges at exactly the same time)

**SPP Winter Risk Period**

*(Three-day period in 2023)*




**Max Hourly Violation of SPP Installed Capacity Requirement (MW)**

| Year | A1 | A2 | B1 | B2 | B3 |
|---|---|---|---|---|---|
| **2025** | 8,902 | 7,606 | 7,246 | 6,421 | 5,970 |
| **2029** | 3,736 | 5,488 | 1,698 | 1,849 | 2,255 |
| **2034** | 3,523 | 3,455 | 0 | 0 | 0 |
| **2040** | 1,826 | 3,190 | 0 | 0 | 0 |
| **2050** | 616 | 1,610 | 0 | 0 | 0 |

# Seasonal RA Risk Conditions across Scenarios

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

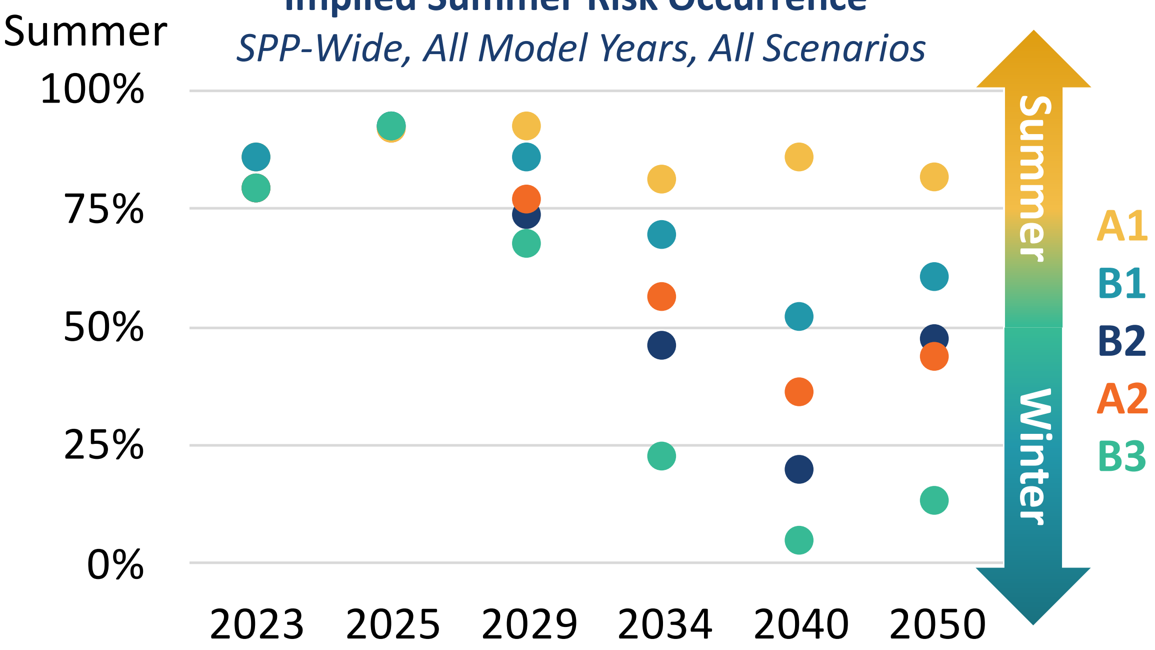
The seasonal frequency of resource adequacy challenges will change as SPP deploys more renewables and electrifies:

- We quantify the seasonal share of the top 100 highest RA-risk hours for each modeled year
- Through the 2020s, most of the top 100 high-risk hours occur in the summer, but winter months hold 8%-26% of the high-risk hours (including the most challenged hours)
- More of the 100 high-risk hours remains concentrated in the summer during the 2020s before shifting to the winter through the 2030s
- Up to 15 GW of 8hr storage capacity is added to SPP between 2040 and 2050, which mitigates winter risk hours relative to summer risk hours

<u>Note:</u> This metric is only a proxy for resource adequacy challenges and does not replace the need for detailed LOLE/resource adequacy modeling.

**Implied Summer Risk Occurrence**

*SPP-Wide, All Model Years, All Scenarios*

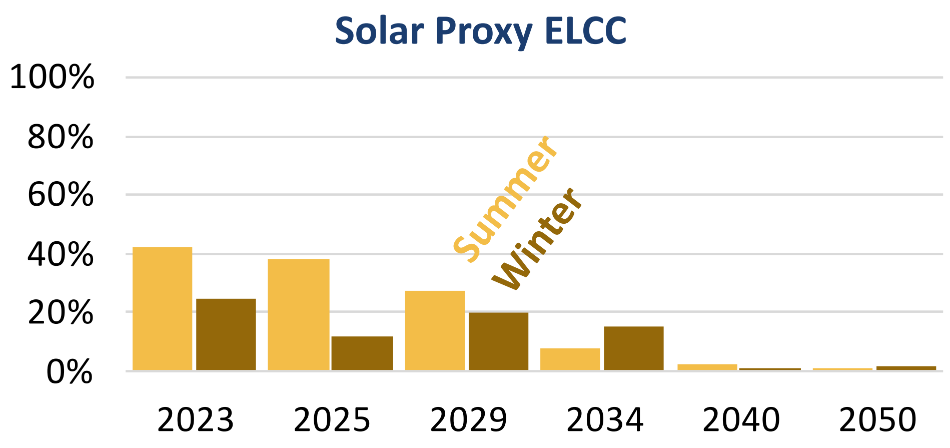


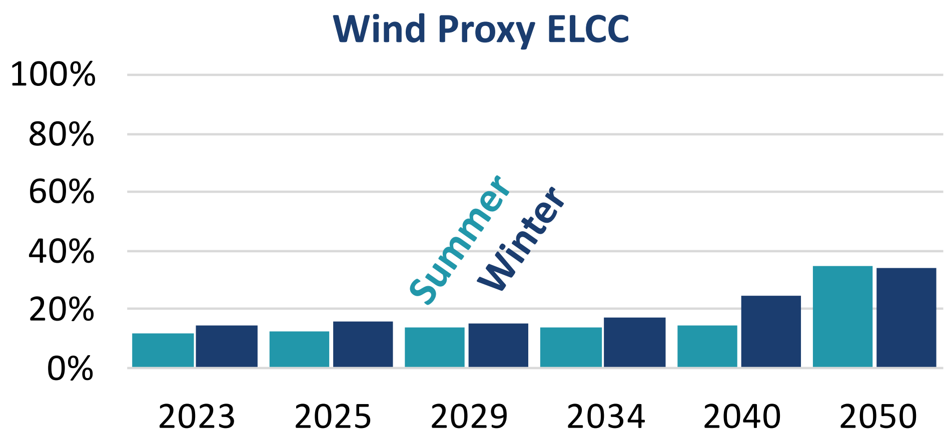

*Notes: Proportion of 100 tightest hours annually in in the summer. Winter risk occurrence is 100% minus Summer risk occurrence. Summer is defined as April – September, winter is October – March.*

# Seasonal Proxy ELCC Values for Wind and Solar (Scenario B2)

Proxy ELCC values are calculated based on the simple average of resource performance during the top 100 resource-adequacy risk hours (with highest net load, adjusted for generation outages) in each modeled year:

- **Through the 2020s:** Renewable ELCC proxy values remain relatively high, although wind generation has already mostly saturated the market
- **In the 2030s:** Solar ELCC proxy values begin to decline as more is added; wind ELCC values have plateaued. Winter ELCC values can increase with shifting RA-risk hours and correlated fossil outages
- **In the 2040s:** Solar proxy ELCC values continue to decline as SPP solar generation investments accelerates in the 2040s. Electrification drives winter RA risk and increases proxy ELCCs for wind generation



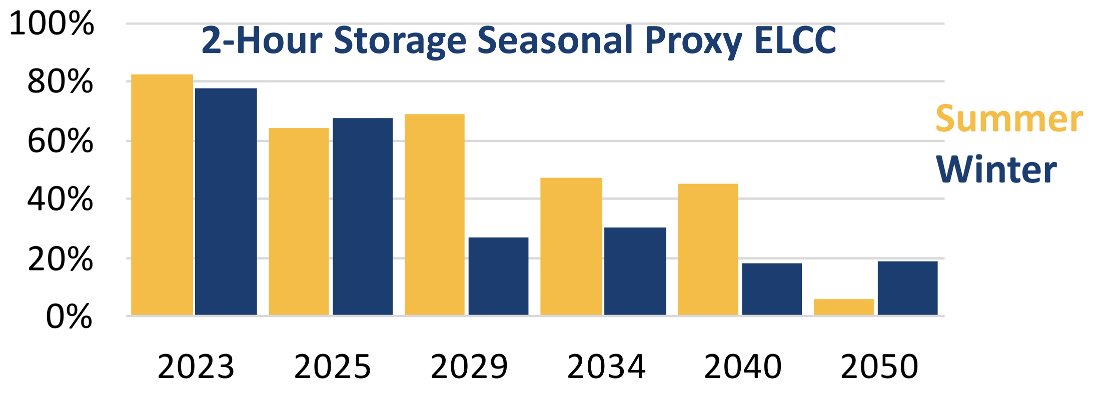

Note: These proxy ELCCs are only approximate and do not replace more detailed ELCC modeling.

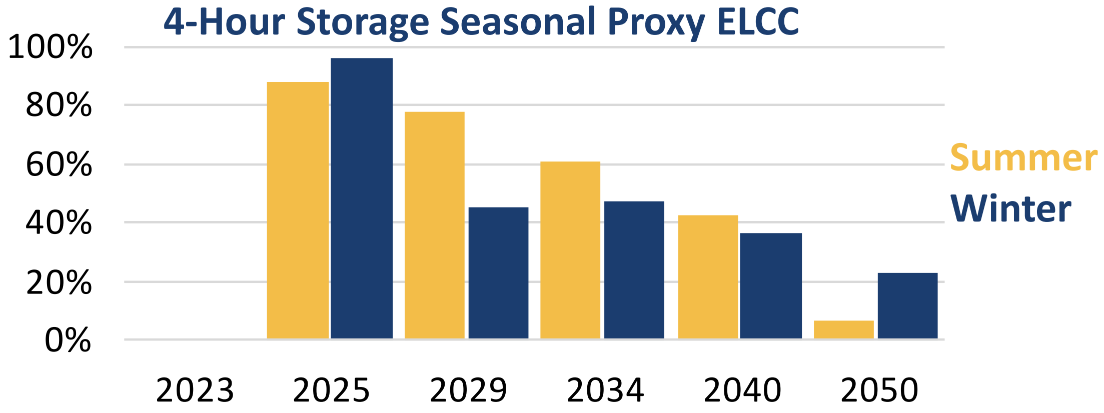
# Seasonal Proxy ELCCs for Storage (Scenario B2)

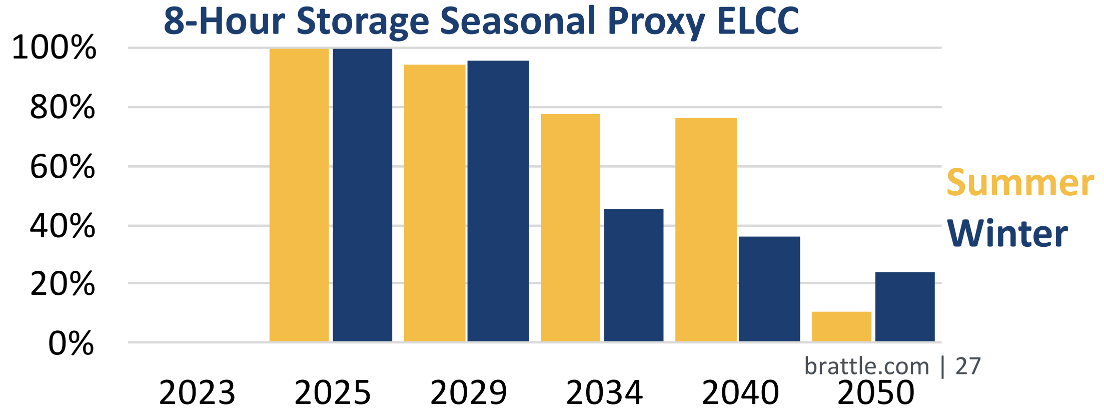
Storage proxy ELCC values decline over the next decade. FERNS models 2hr, 4hr, and 8hr battery storage assets:

- **Through the 2020s:** Storage has the highest proxy ELCC values
- **In the 2030s:** Storage ELCC values begin decline quickly for shorter-duration batteries. 8hr storage (with only limited deployment) maintains high proxy ELCC values
- **In the 2040s:** Even 8hr storage shows declining proxy ELCC values, suggesting that longer duration storage may be a more cost-effective resource (FERNS modeling did not include battery storage with durations greater than 8hrs)

<u>Note</u>: These proxy ELCCs are only approximate and do not replace more detailed ELCC modeling.



# Proxy ELCCs (Scenario B2) Compared to SPP's Current ELCC Estimates

We compare FERNS proxy ELCCs to SPP's REAL Study from Future Resource Mix Study (May 2024). FERNS proxy ELCC values only serve as illustrative estimates based on hourly generation capability during the 100 highest RA-risk hours. SPP did not forecast annual ELCCs, but instead looked at multiple resource scenarios for 2029. We compare FERNS proxy values to 2029 SPP-provided values to serve as a benchmark and allow for PRM calculations

## Modeled Seasonal Proxy ELCC Values

*SPP-Wide, Scenario B2*

| | Modeled Renewable Capacity (GW) | | | | | | Seasonal Modeled Proxy ELCC Values (%) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Wind | Solar | Fossil | 2-Hour Storage | 4-Hour Storage | 8-Hour Storage | Wind | Solar | Fossil | 2-Hour Storage | 4-Hour Storage | 8-Hour Storage |
| ***Winter*** | | | | | | | | | | | | |
| **2023** | 34 | 1 | 54 | 0 | 0 | 0 | *14%* | *25%* | *72%* | *78%* | *N/A* | *N/A* |
| **2025** | 38 | 2 | 55 | 4 | 0 | 0 | *16%* | *12%* | *70%* | *67%* | *96%* | *100%* |
| **2029** | 53 | 10 | 53 | 4 | 7 | 0 | *15%* | *20%* | *77%* | *27%* | *46%* | *96%* |
| **2034** | 66 | 27 | 45 | 4 | 11 | 7 | *17%* | *15%* | *78%* | *30%* | *47%* | *45%* |
| **2040** | 66 | 58 | 41 | 4 | 13 | 18 | *24%* | *1%* | *81%* | *18%* | *36%* | *36%* |
| **2050** | 68 | 108 | 42 | 4 | 13 | 34 | *34%* | *1%* | *81%* | *19%* | *23%* | *24%* |
| ***Summer*** | | | | | | | | | | | | |
| **2023** | 34 | 1 | 54 | 0 | 0 | 0 | *12%* | *42%* | *92%* | *82%* | *N/A* | *N/A* |
| **2025** | 38 | 2 | 55 | 4 | 0 | 0 | *13%* | *38%* | *92%* | *64%* | *88%* | *100%* |
| **2029** | 53 | 10 | 53 | 4 | 7 | 0 | *14%* | *27%* | *92%* | *69%* | *78%* | *95%* |
| **2034** | 66 | 27 | 45 | 4 | 11 | 7 | *14%* | *8%* | *93%* | *47%* | *61%* | *78%* |
| **2040** | 66 | 58 | 41 | 4 | 13 | 18 | *14%* | *2%* | *90%* | *45%* | *43%* | *76%* |
| **2050** | 68 | 108 | 42 | 4 | 13 | 34 | *35%* | *0%* | *91%* | *6%* | *6%* | *11%* |

*Note: Summer is defined as April – September, winter is October – March. Seasonal proxy ELCC is calculated based on resource contribution in top 100 tightest hours annually.*

## SPP-Provided ELCCs

| | Capacity (GW) | | | SPP Provided ELCC (%) | | |
|---|---|---|---|---|---|---|
| Scenario | Wind | Solar | 4-Hour Storage | Wind | Solar | 4-Hour Storage |
| ***Winter*** | | | | | | |
| 1 | 40 | 10 | 5 | *26%* | *19%* | *18%* |
| 2 | 40 | 20 | 5 | *24%* | *15%* | *22%* |
| 3 | 52 | 20 | 5 | *23%* | *15%* | *25%* |
| 4 | 59 | 24 | 10 | *22%* | *16%* | *19%* |
| 5 | 60 | 30 | 10 | *21%* | *14%* | *21%* |
| 6 | 60 | 30 | 20 | *21%* | *16%* | *17%* |
| ***Summer*** | | | | | | |
| 1 | 40 | 10 | 5 | *20%* | *57%* | *44%* |
| 2 | 40 | 20 | 5 | *18%* | *42%* | *78%* |
| 3 | 52 | 20 | 5 | *17%* | *43%* | *71%* |
| 4 | 59 | 24 | 10 | *17%* | *41%* | *61%* |
| 5 | 60 | 30 | 10 | *17%* | *36%* | *60%* |
| 6 | 60 | 30 | 20 | *18%* | *35%* | *42%* |

*Note: SPP values reflect 2029 demand conditions under 6 resource mix scenario buildouts. Comparable scenarios are mapped to FERNS model years based on capacity mix.*

# Seasonal Proxy ELCC Values Across Scenarios

| Carbon Free Resource Shares → / Electrification ↓ | Moderate | High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

**Winter**

| Scenario | Year | Proxy ELCC (%) Wind | Solar | Fossil | 2-Hour Storage | 4-Hour Storage | 8-Hour Storage |
|---|---|---|---|---|---|---|---|
| B2 | 2023 | 14% | 25% | 72% | 78% | N/A | N/A |
| | 2025 | 16% | 12% | 70% | 67% | 96% | 100% |
| | 2029 | 15% | 20% | 77% | 27% | 46% | 96% |
| | 2034 | 17% | 15% | 78% | 30% | 47% | 45% |
| | 2040 | 24% | 1% | 81% | 18% | 36% | 36% |
| | 2050 | 34% | 1% | 81% | 19% | 23% | 24% |
| B1 | 2023 | 15% | 14% | 71% | 82% | N/A | N/A |
| | 2025 | 16% | 13% | 70% | 71% | 95% | 100% |
| | 2029 | 16% | 8% | 75% | 33% | 33% | 94% |
| | 2034 | 20% | 13% | 77% | 35% | 34% | 48% |
| | 2040 | 24% | 2% | 80% | 31% | 38% | 32% |
| | 2050 | 34% | 1% | 80% | 27% | 26% | 27% |
| B3 | 2023 | 14% | 25% | 72% | 73% | N/A | N/A |
| | 2025 | 16% | 12% | 70% | 67% | 95% | 100% |
| | 2029 | 15% | 31% | 76% | 28% | 36% | 90% |
| | 2034 | 18% | 11% | 80% | 47% | 54% | 66% |
| | 2040 | 23% | 1% | 81% | 41% | 51% | 52% |
| | 2050 | 25% | 1% | 81% | 48% | 53% | 62% |
| A1 | 2023 | 15% | 14% | 71% | 82% | N/A | N/A |
| | 2025 | 16% | 11% | 70% | 81% | 100% | 100% |
| | 2029 | 16% | 13% | 70% | 61% | 58% | 100% |
| | 2034 | 15% | 29% | 76% | 24% | 30% | 100% |
| | 2040 | 16% | 4% | 78% | 32% | 40% | 99% |
| | 2050 | 19% | 3% | 76% | 36% | 51% | 74% |
| A2 | 2023 | 14% | 25% | 72% | 78% | N/A | N/A |
| | 2025 | 16% | 11% | 70% | 74% | 100% | 100% |
| | 2029 | 15% | 22% | 76% | 29% | 37% | 100% |
| | 2034 | 17% | 29% | 77% | 21% | 36% | 100% |
| | 2040 | 18% | 13% | 79% | 19% | 34% | 99% |
| | 2050 | 22% | 1% | 81% | 34% | 48% | 74% |

**Summer**

| Scenario | Year | Proxy ELCC (%) Wind | Solar | Fossil | 2-Hour Storage | 4-Hour Storage | 8-Hour Storage |
|---|---|---|---|---|---|---|---|
| B2 | 2023 | 12% | 42% | 92% | 82% | N/A | N/A |
| | 2025 | 13% | 38% | 92% | 64% | 88% | 100% |
| | 2029 | 14% | 27% | 92% | 69% | 78% | 95% |
| | 2034 | 14% | 8% | 93% | 47% | 61% | 78% |
| | 2040 | 14% | 2% | 90% | 45% | 43% | 76% |
| | 2050 | 35% | 0% | 91% | 6% | 6% | 11% |
| B1 | 2023 | 11% | 44% | 92% | 84% | N/A | N/A |
| | 2025 | 12% | 39% | 92% | 61% | 83% | 100% |
| | 2029 | 14% | 29% | 92% | 68% | 75% | 96% |
| | 2034 | 16% | 7% | 92% | 48% | 53% | 76% |
| | 2040 | 16% | 3% | 89% | 53% | 52% | 76% |
| | 2050 | 32% | 2% | 91% | 4% | 8% | 15% |
| B3 | 2023 | 12% | 42% | 92% | 83% | N/A | N/A |
| | 2025 | 13% | 38% | 92% | 65% | 89% | 100% |
| | 2029 | 15% | 21% | 93% | 57% | 66% | 91% |
| | 2034 | 12% | 5% | 93% | 51% | 49% | 73% |
| | 2040 | 14% | 0% | 94% | 23% | 33% | 45% |
| | 2050 | 26% | 0% | 89% | 11% | 15% | 24% |
| A1 | 2023 | 11% | 44% | 92% | 84% | N/A | N/A |
| | 2025 | 11% | 45% | 92% | 77% | 100% | 100% |
| | 2029 | 13% | 35% | 92% | 74% | 80% | 100% |
| | 2034 | 17% | 21% | 93% | 57% | 64% | 97% |
| | 2040 | 23% | 3% | 93% | 25% | 31% | 89% |
| | 2050 | 24% | 1% | 92% | 31% | 38% | 80% |
| A2 | 2023 | 12% | 42% | 92% | 82% | N/A | N/A |
| | 2025 | 12% | 39% | 92% | 65% | 98% | 100% |
| | 2029 | 14% | 29% | 92% | 70% | 76% | 99% |
| | 2034 | 22% | 9% | 93% | 43% | 52% | 98% |
| | 2040 | 23% | 1% | 93% | 21% | 34% | 92% |
| | 2050 | 30% | 0% | 93% | 10% | 28% | 73% |

Preliminary draft.

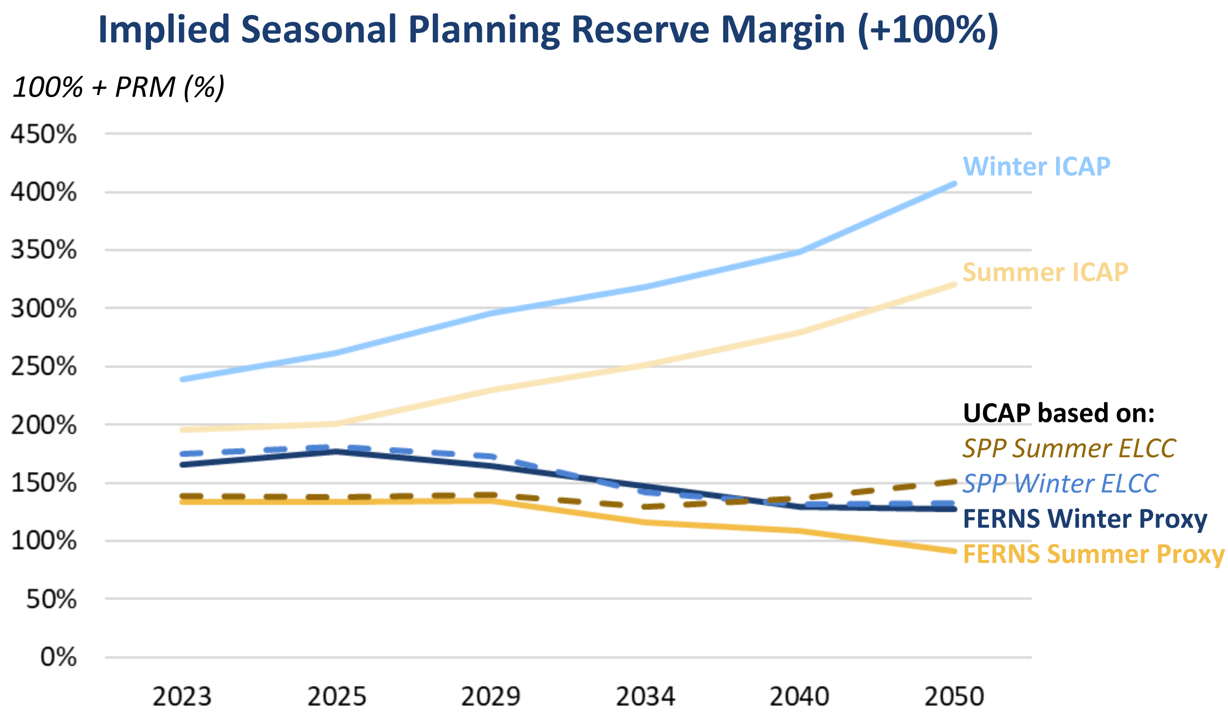
*Note: Summer is defined as April – September, winter is October – March. Seasonal proxy ELCC is calculated based on resource contribution in top 100 tightest hours annually.*

# SPP Seasonal Planning Reserve Margins (Scenario B2)

We estimate implied future planning reserve margins (relative to weather-normalized peak load) for FERNS Scenario B2, using three methods to estimate rated capacity:

- Based on installed nameplate capacity (ICAP)
- With SPP's 2029 ELCC values from the Future Resource Mix Study (Scenario ELCCs selected based on FERNS annual capacity)
- With proxy ELCC from FERNS simulation results (contributions during top 100 hours)

Irrespective of "reserve margins", all model results meet system-wide and zonal resource adequacy needs on an hourly basis.




*Note: SPP ELCC values come from Future Resource Mix Study, May 2024. 100% means the capacity is equal to peak load in that year (i.e. 0% PRM).*

<u>Note</u>: PRMs are expressed as % of seasonal weather-normalized peak load. They decline (even below 100%) as RA violations shift into evening hours with lower gross load (but high net loads).

# SPP Planning Reserve Margins Across Scenarios

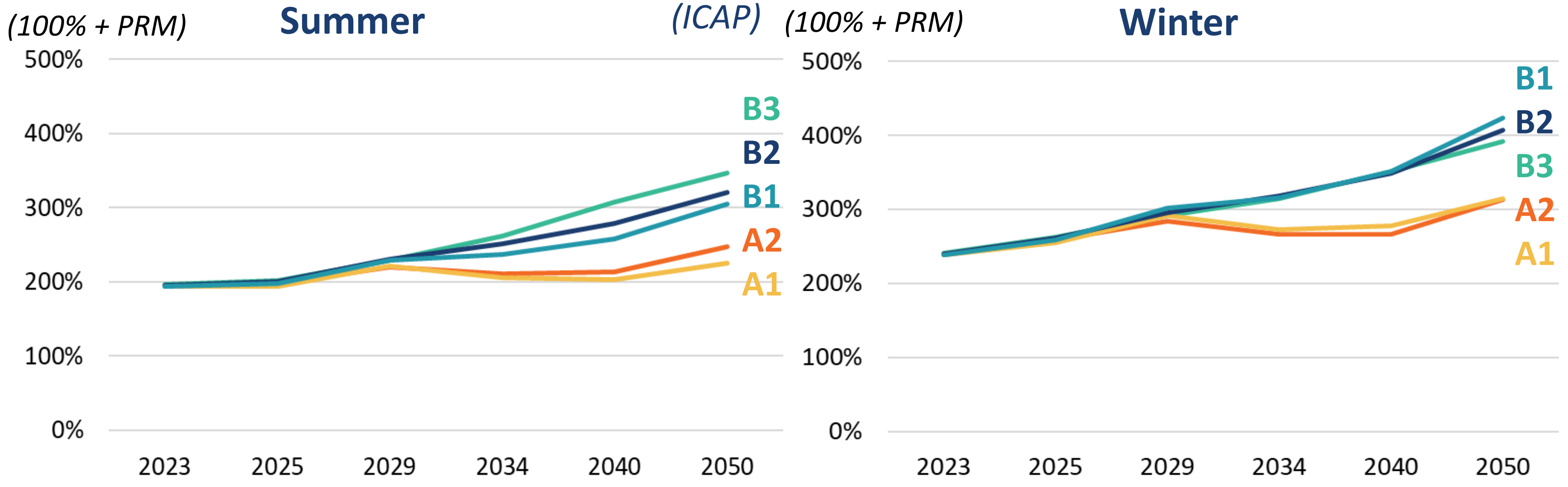
| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

The charts show estimated future implied planning reserve margins (PRM) across FERNS scenarios based on the weather-normalized gross peak load relative to (1) installed capacity; and (2) rated capacity based on model-based proxy ELCCs.

Overall, these results suggest that **planning reserve margins applied to weather-normalized (gross) peak load will become less useful as the sole resource adequacy metric starting in the 2030s**, when RA challenges shift away from peak load hours. (For example, PRMs for load during the most resource-adequacy-challenged hours may be a more suitable alternative).

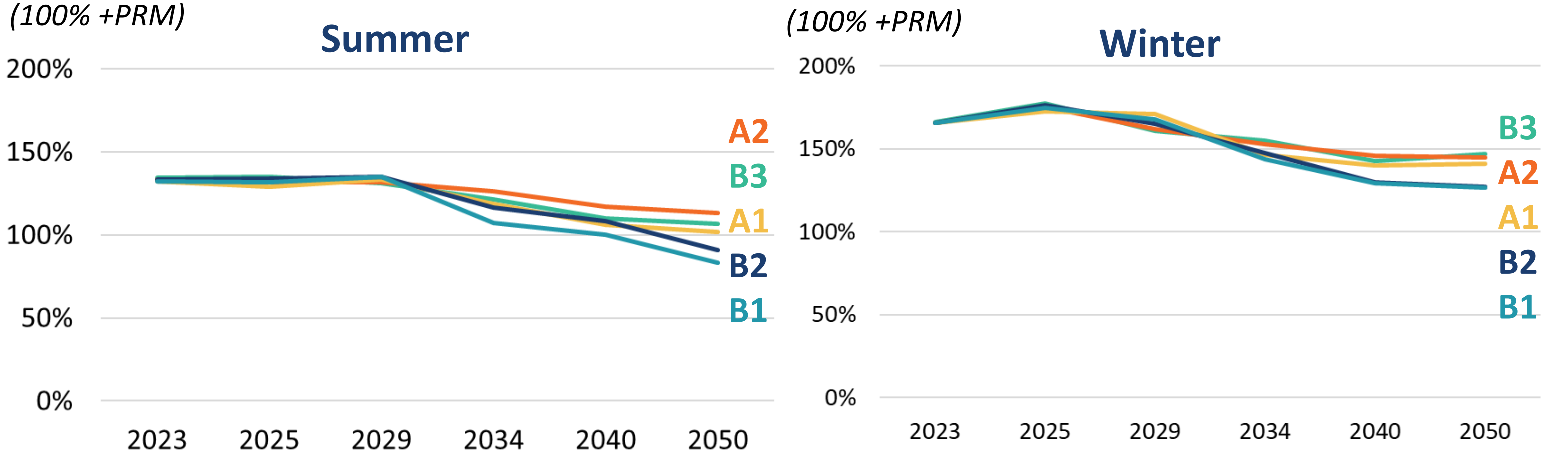
**SPP Implied Planning Reserve Margin**

*(ICAP)*




**SPP Implied Planning Reserve Margin**

*(FERNS model-based proxy ELCC)*




*Note: Reserve margins are calculated as % of seasonal weather-normalized peak gross load and based on FERNS proxy ELCCs in bottoms charts and total ICAP in top chart. Scale of vertical axis differs by figure. 100% means the capacity is equal to peak load in that year (i.e. 0% PRM).*

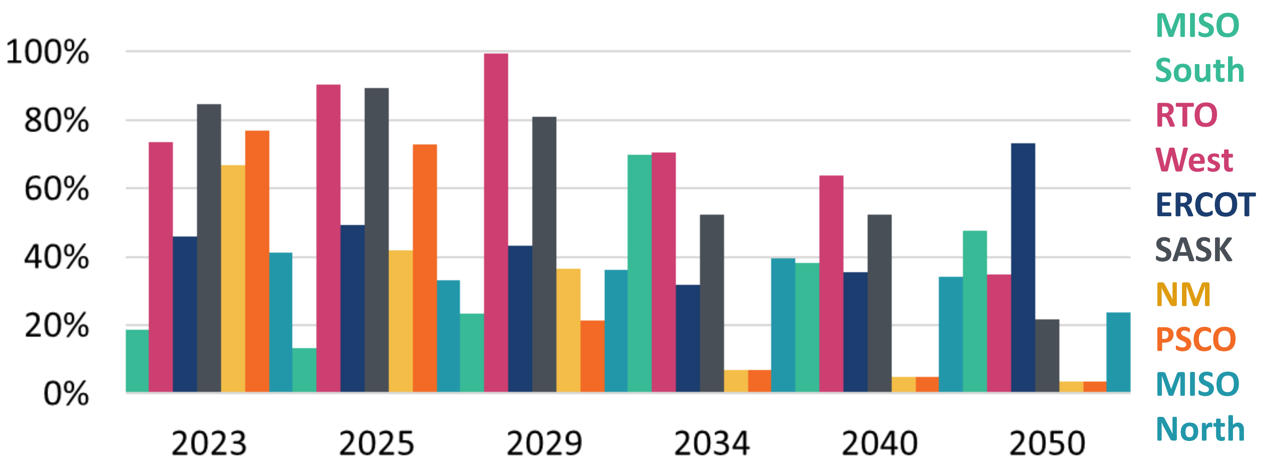
# RA Value of Uncommitted Interties with Neighbors (Scenario B2)

Although interties with neighboring regions are not assumed to contribute to SPP resource adequacy requirements, SPP can often import energy to serve load during scarcity periods. We quantified the implied proxy "ELCC" value based on the (non-firm) energy imports to SPP over external interfaces during the 100 highest resource adequacy risk hours:

- **Through the 2020s:** Interties of western and northern neighbors are most valuable during high RA-risk hours
- **In the 2030s:** The RA value of interties is less; MISO South and RTO West have the highest value during SPP's high RA risk hours
- **In the 2040s:** The average RA value of (uncommitted) interties remains at approximately 30% of their (uncommitted) capacity, interties with MISO, RTO west, and ERCOT have highest RA value

These proxy ELCCs represent the incremental RA value provided by non-firm energy imports available from neighboring zones during SPP scarcity hours. FERNS relies on only a simplified representation of neighboring zones, so more detailed analyses are needed to confirm the RA value of interties to neighboring regions. See Appendix 1 for more information on external zone modeling approach.

## Implied "Proxy ELCCs" of Non-firm Energy Imports over Interties with Neighboring Regions (Scenario B2)




## Intertie Capacity (MW)

| MISO South | MISO North | RTO West |
|---|---|---|
| 2,486 (into SPP)<br>2,708 (out of SPP) | 2,165 (into SPP)<br>4,203 (out of SPP) | 2023-2034: 700<br>2034-2040: 1,400<br>2040 onwards: 2,400 |

| New Mexico | ERCOT | SASK | PSCo |
|---|---|---|---|
| 400 | 800 | 2023 - 2029: 150<br>2029 onwards: 650 | 210 |

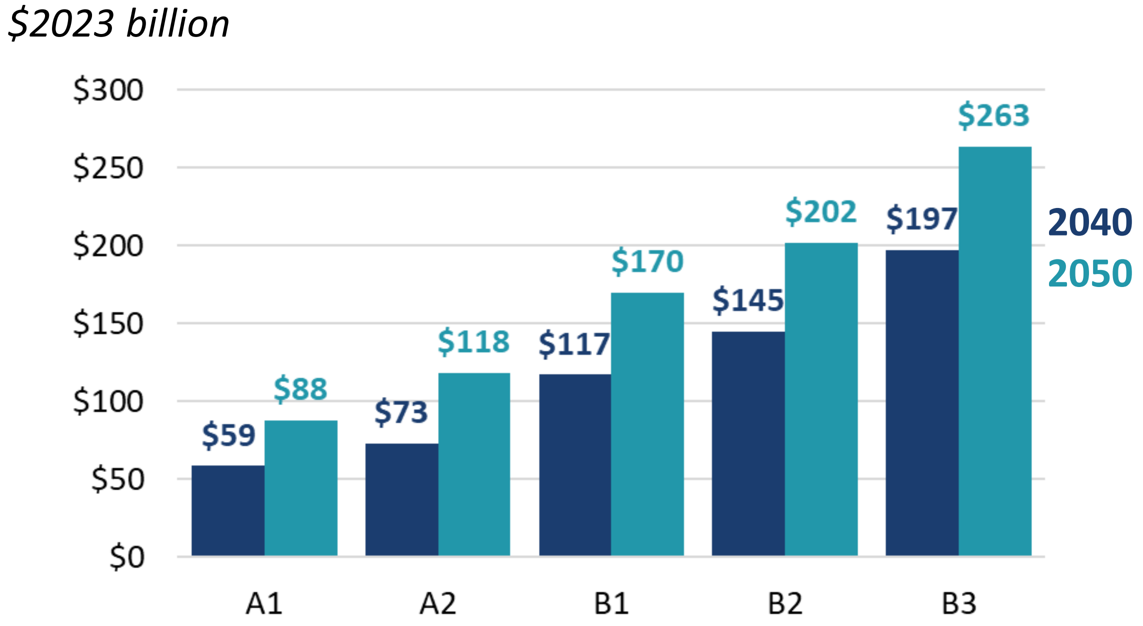
# Forecasted Cumulative Investment Needs by Scenario

| | | Carbon Free Resource Shares | |
|---|---|---|---|
| | | Moderate | High |
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

Through 2050, between $88 and $263 billion of additional generation investment is required to meet SPP's future system needs:

- Total generation (capital) investment is highest in high carbon-free and highly electrified scenarios
- This is primarily due to the significant generation capacity additions needed to maintain resource adequacy in high-load scenarios
- With continued tax credits (or similar state or corporate clean-energy support), high renewable generation investments yield lower total costs
- As a result, total system costs (see next slides) vary much less than capital investment costs

**SPP Cumulative Generator Capex Investment Needs (2023-2050)**
*($2023 billion)*




*Note: Costs are in $2023 dollars. Includes only incremental CAPEX based on net additions. Does not net out value of tax credits. Excludes all transmission costs including those associated with zonal generator interconnection.*

# Total System Costs (Future G+T only) for Scenario B2

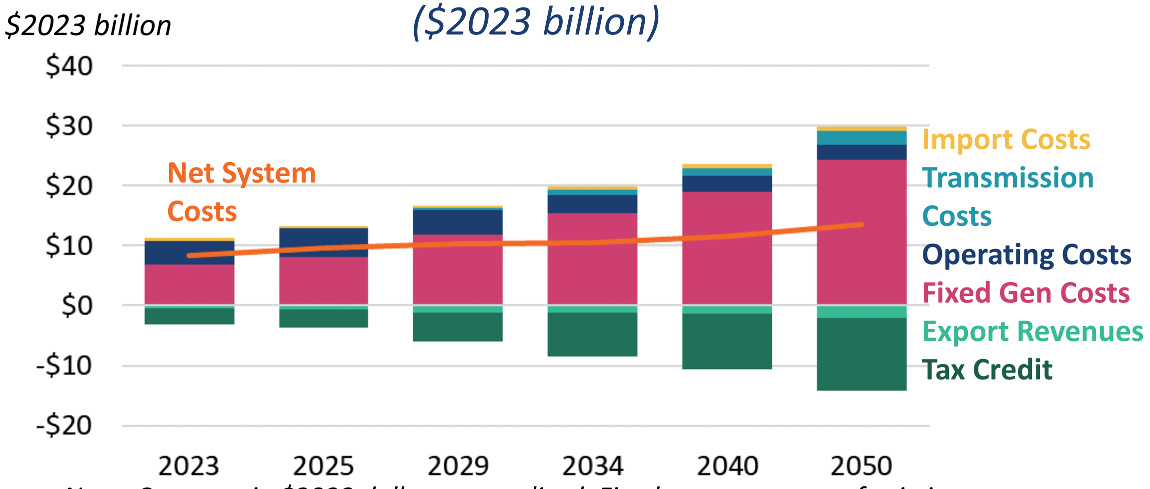
Total annualized generation and transmission costs (in inflation-adjusted 2023 dollars) increase over the modeling horizon as additional resources are built and dispatched to serve growing demand.

The simulated generation and transmission cost increases are presented on an annualized basis (in nominal dollars) and include:

- Fixed Gen costs (FOM, Annualized New Gen CAPEX Costs)
- Operating costs (Fuel Costs, VOM, Start Costs)
- Tax Credits (PTC, ITC)
- Import Costs (incl. Wheeling Costs)
- Export Revenues (incl. Wheeling Revenues)
- Transmission Costs (Interzonal Transmission Costs, Generator Interconnection Costs)

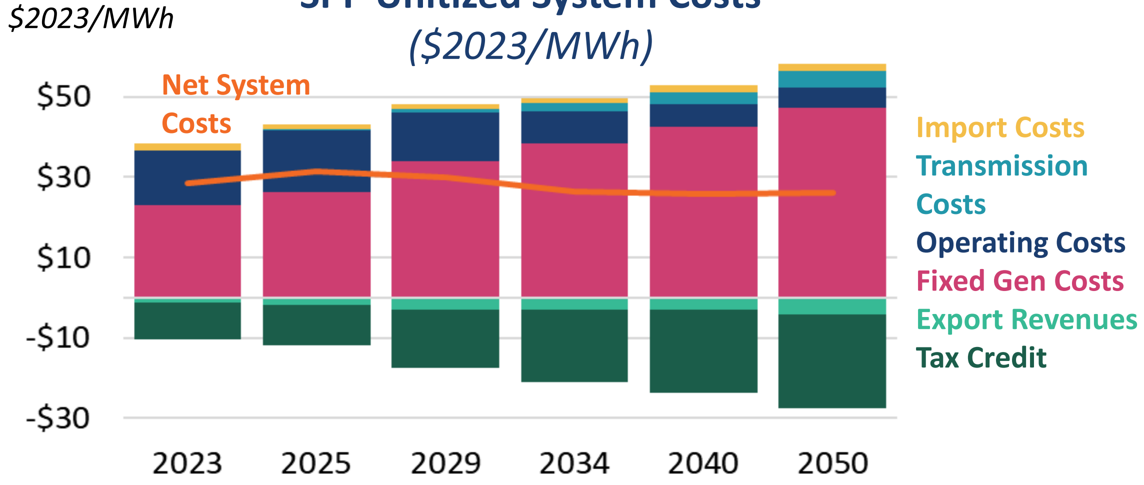
<u>Note</u>: These costs do <u>not</u> include (a) distribution costs or (b) investment cost recovery for existing generation and transmission.

**SPP Annualized System Costs**
*($2023 billion)*




*Note: Costs are in $2023 dollars, annualized. Fixed costs recovery of existing generation not included.*

**SPP Unitized System Costs**
*($2023/MWh)*




*Note: Costs are in $2023 dollars and allocated over MWh of SPP system gross load. Fixed costs recovery of existing generation not included.*

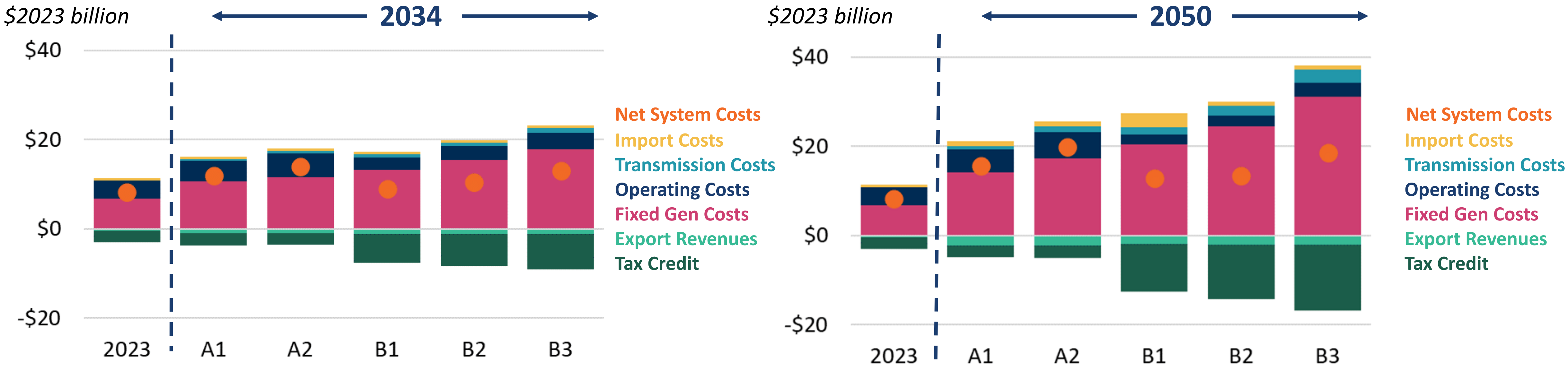
# Total Annualized System Costs Across Scenarios

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

Total G+T costs (in 2023 dollars) increase over time in all scenarios as SPP electrifies and decarbonizes:

- Moderate carbon-free resource scenarios (A1, A2) have higher overall costs, driven by the operating costs of fossil generation and limited PTC/ITC tax credits
- Most of the cost increases are driven by generation investment (and fixed O&M) costs needed to serve growing load
- Total SPP-wide costs are lower (in Scenarios B1-B3) if PTC/ITC tax credits remain available

**SPP System Costs**
*($2023 billion)*




*Note: Costs are in $2023 thousand dollars. Fixed costs recovery of existing generation not included.*

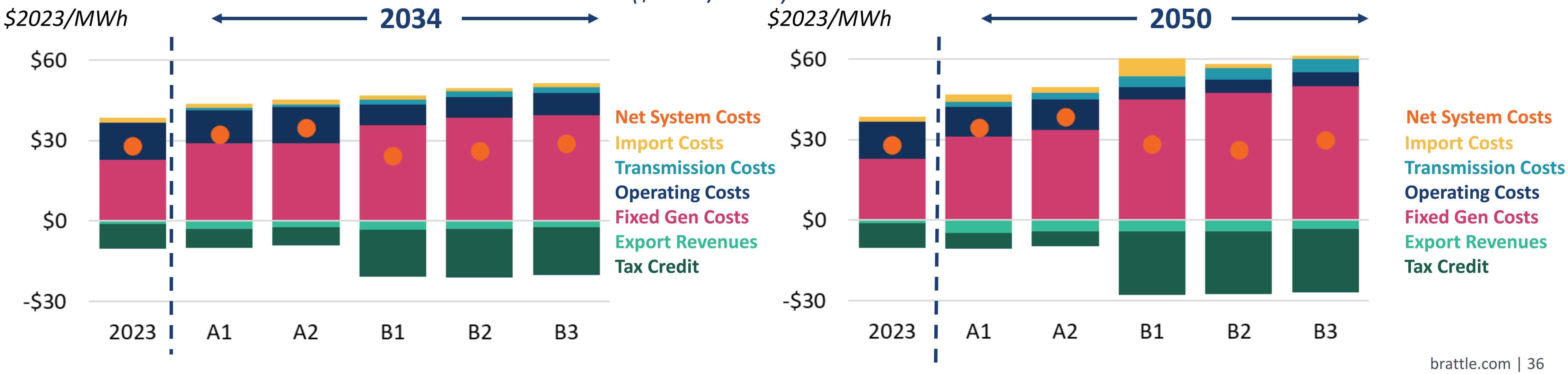
# $/MWh Costs Across Scenarios

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

Per unit system costs (total annualized cost divided by total annual load, in inflation-adjusted 2023 dollars) show only modest increases in Scenarios A1 – A2 and no increases in Scenarios B1 – B3:

- Moderate carbon-free resource scenarios (A1, A2) have slight $/MWh cost increases driven by additional fossil fixed and operational investments, while B scenarios have no cost increases due to the higher value of tax credits
- On a per-MWh basis, differences in electrification scenarios do not drive significant differences in system costs
- This suggests SPP could achieve high levels of decarbonization and electrification with minimal rate impacts

**SPP Unitized System Costs**
*($2023/MWh)*




*Note: costs are in $2023 dollars and allocated over MWh of SPP system gross load. Fixed costs recovery of existing generation not included.*

# Import Costs and Export Revenues

**Import costs and export revenues shown in prior slides are calculated at follows:**

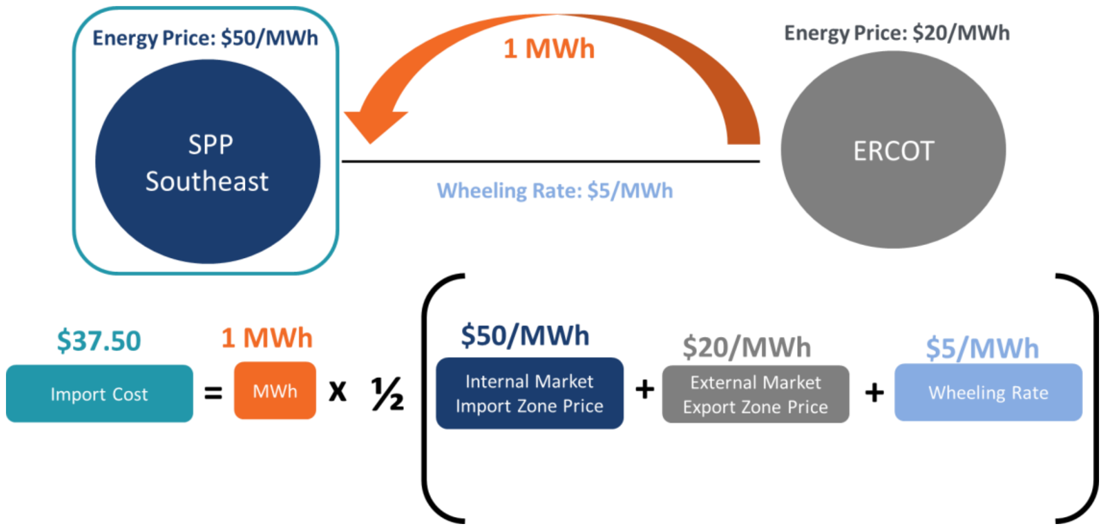
### Import Costs (*incl. Wheeling Costs*)

= MWh * 0.5 (Internal Market Import Zone Price + External Market Export Zone Price + Wheeling Rate) summed hourly over all imports between pairs of internal importing zone and external exporting zone

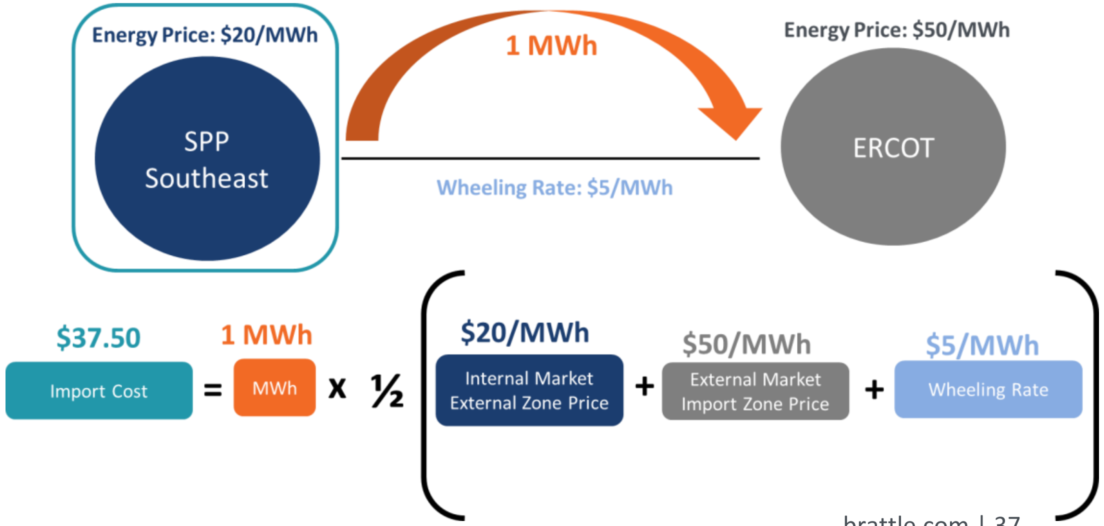
### Export Revenues (*incl. Wheeling Revenues*)

= MWh * 0.5 (External Market Import Zone Price + Internal Market Export Zone Price + Wheeling Rate) summed hourly over all exports between pairs of internal exporting zone and external importing zone

**SPP Import Cost Example**




**SPP Export Revenue Example**



# SPP Capacity— All Scenarios (GW)

| Electrification | Carbon Free Resource Shares: Moderate | High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| | Scenario A1 | | | | | | Scenario A2 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 20.9 | 19.9 | 18.5 | 17.8 | 17.8 | 17.8 | 20.9 | 19.9 | 18.5 | 18.5 | 18.5 | 18.5 |
| NG | 31.5 | 33.8 | 33.2 | 27.6 | 27.9 | 30.8 | 31.5 | 33.8 | 33.2 | 36.9 | 42.5 | 43.7 |
| Nuclear | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Oil | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Pumped Storage | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | 0.4 | 1.8 | 8.0 | 8.0 | 14.8 | 42.9 | 0.4 | 1.8 | 8.0 | 8.0 | 17.6 | 54.2 |
| 2-Hour Storage | 0.1 | 0.8 | 0.8 | 8.0 | 11.0 | 11.0 | 0.1 | 2.5 | 2.5 | 9.4 | 13.3 | 13.3 |
| 4-Hour Storage | - | - | 6.6 | 6.6 | 6.6 | 8.8 | - | - | 6.6 | 6.6 | 6.6 | 9.1 |
| 8-Hour Storage | - | - | - | - | - | 2.5 | - | - | - | - | - | 6.7 |
| Onshore Wind | 34.2 | 37.5 | 50.7 | 50.7 | 50.7 | 53.7 | 34.2 | 37.5 | 50.7 | 50.7 | 50.9 | 58.8 |
| Hydro | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| **Total** | **96.2** | **102.9** | **126.9** | **127.7** | **137.8** | **176.5** | **96.2** | **104.6** | **128.6** | **139.2** | **158.4** | **213.4** |

| | Scenario B1 | | | | | | Scenario B2 | | | | | | Scenario B3 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 20.9 | 19.9 | 18.5 | 11.9 | 5.2 | 3.8 | 20.9 | 19.9 | 18.5 | 14.7 | 11.1 | 11.1 | 20.9 | 19.9 | 18.5 | 16.0 | 15.4 | 15.4 |
| NG | 31.5 | 33.8 | 33.2 | 24.6 | 24.6 | 24.6 | 31.5 | 33.8 | 33.2 | 28.1 | 28.1 | 29.5 | 31.5 | 33.8 | 33.2 | 38.5 | 41.4 | 47.6 |
| Nuclear | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Oil | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| Pumped Storage | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | 0.4 | 1.9 | 10.1 | 24.0 | 47.5 | 95.4 | 0.4 | 1.9 | 10.3 | 26.6 | 57.7 | 108.5 | 0.4 | 1.9 | 10.3 | 28.4 | 74.1 | 130.8 |
| 2-Hour Storage | 0.1 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 0.1 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 0.1 | 4.5 | 5.6 | 5.6 | 5.6 | 5.6 |
| 4-Hour Storage | - | - | 6.6 | 12.9 | 12.9 | 12.9 | - | - | 6.6 | 11.4 | 12.8 | 12.8 | - | - | 6.6 | 8.4 | 8.4 | 8.4 |
| 8-Hour Storage | - | - | - | 2.6 | 12.5 | 28.3 | - | - | - | 6.8 | 18.3 | 34.0 | - | - | - | 9.3 | 29.4 | 45.6 |
| Onshore Wind | 34.2 | 37.5 | 51.2 | 60.4 | 60.7 | 61.9 | 34.2 | 37.5 | 52.8 | 65.9 | 66.2 | 68.4 | 34.2 | 37.5 | 54.6 | 73.9 | 78.8 | 82.3 |
| Hydro | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| **Total** | **96.2** | **104.6** | **131.0** | **147.7** | **174.8** | **238.3** | **96.2** | **106.0** | **134.3** | **166.2** | **207.1** | **277.1** | **96.2** | **106.7** | **137.9** | **189.1** | **262.1** | **344.7** |

# Zonal Capacity—Scenario A1 (GW)

| Electrification | Carbon Free Resource Shares | |
|---|---|---|
| | Moderate | High |
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.8 | 3.8 | 3.5 | 3.5 | 3.5 | 3.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| NG | 1.6 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.0 | 2.6 | 2.6 | 2.5 | 2.5 | 2.5 | 1.0 | 1.0 | 1.0 | 0.6 | 1.0 | 3.8 |
| Nuclear | - | - | - | - | - | - | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | - | - | - | - | - | - |
| Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.1 | 0.7 | 0.7 | 0.7 | 2.5 | - | 0.1 | 1.1 | 1.1 | 1.1 | 6.1 | - | 0.2 | 1.2 | 1.2 | 1.2 | 1.9 |
| 2-Hour Storage | - | 0.1 | 0.1 | 1.6 | 1.6 | 1.6 | - | - | - | 0.8 | 0.8 | 0.8 | - | 0.5 | 0.5 | 2.5 | 2.5 | 2.5 |
| 4-Hour Storage | - | - | 0.7 | 0.7 | 0.7 | 0.7 | - | - | 1.0 | 1.0 | 1.0 | 1.0 | - | - | 0.6 | 0.6 | 0.6 | 0.6 |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | 0.3 | - | - | - | - | - | 0.1 |
| Onshore Wind | 3.5 | 4.7 | 6.5 | 6.5 | 6.5 | 6.6 | 3.5 | 4.4 | 6.2 | 6.2 | 6.2 | 9.1 | 4.2 | 4.2 | 6.6 | 6.6 | 6.6 | 6.6 |
| Hydro | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - | - | - | - | - | - |
| **Total** | **10.1** | **12.1** | **15.2** | **16.7** | **16.7** | **18.5** | **10.5** | **12.2** | **15.7** | **16.3** | **16.3** | **24.4** | **5.5** | **6.3** | **10.3** | **11.9** | **12.3** | **15.9** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 6.8 | 6.8 | 6.2 | 5.4 | 5.4 | 5.4 | 2.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 5.7 | 5.7 | 5.3 | 5.3 | 5.3 | 5.3 |
| NG | 5.7 | 5.7 | 6.0 | 5.8 | 5.8 | 5.8 | 4.5 | 5.8 | 5.8 | 7.2 | 7.2 | 7.2 | 16.7 | 16.7 | 15.7 | 9.4 | 9.4 | 9.4 |
| Nuclear | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | - | 0.2 | 1.0 | 1.0 | 1.0 | 7.6 | 0.3 | 0.4 | 1.0 | 1.0 | 4.2 | 10.5 | 0.1 | 0.8 | 3.0 | 3.0 | 6.5 | 14.3 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | 0.1 | 0.6 | 0.6 | 0.1 | 0.1 | 0.1 | 2.9 | 5.4 | 5.4 |
| 4-Hour Storage | - | - | 1.2 | 1.2 | 1.2 | 1.2 | - | - | 0.7 | 0.7 | 0.7 | 1.4 | - | - | 2.4 | 2.4 | 2.4 | 3.9 |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | 1.9 | - | - | - | - | - | 0.2 |
| Onshore Wind | 5.8 | 6.2 | 8.8 | 8.8 | 8.8 | 8.8 | 4.6 | 4.7 | 5.7 | 5.7 | 5.7 | 5.7 | 12.6 | 13.4 | 16.9 | 16.9 | 16.9 | 16.9 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total** | **20.5** | **21.0** | **25.3** | **24.4** | **24.4** | **31.0** | **11.5** | **11.9** | **14.2** | **15.8** | **19.6** | **28.4** | **38.0** | **39.4** | **46.2** | **42.6** | **48.6** | **58.2** |

| Carbon Free Resource Shares | | Moderate | High |
|---|---|---|---|
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

## APPENDIX 2: DETAILED ZONAL SCENARIO—GENERATION CAPACITY

# Zonal Capacity—Scenario A2 (GW)

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.8 | 3.8 | 3.5 | 3.5 | 3.5 | 3.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| NG | 1.6 | 2.1 | 2.1 | 2.9 | 3.0 | 3.7 | 2.0 | 2.6 | 2.6 | 3.4 | 4.3 | 4.3 | 1.0 | 1.0 | 1.0 | 5.3 | 5.3 | 5.3 |
| Nuclear | - | - | - | - | - | - | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | - | - | - | - | - | - |
| Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.1 | 0.7 | 0.7 | 0.7 | 5.0 | - | 0.1 | 1.1 | 1.1 | 1.1 | 5.9 | - | 0.2 | 1.2 | 1.2 | 1.2 | 3.0 |
| 2-Hour Storage | - | 1.2 | 1.2 | 3.0 | 4.7 | 4.7 | - | - | - | 0.2 | 0.4 | 0.4 | - | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| 4-Hour Storage | - | - | 0.7 | 0.7 | 0.7 | 0.7 | - | - | 1.0 | 1.0 | 1.0 | 1.9 | - | - | 0.6 | 0.6 | 0.6 | 0.6 |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | 0.7 | - | - | - | - | - | 0.8 |
| Onshore Wind | 3.5 | 4.7 | 6.5 | 6.5 | 6.5 | 7.5 | 3.5 | 4.4 | 6.2 | 6.2 | 6.4 | 13.4 | 4.2 | 4.2 | 6.6 | 6.6 | 6.6 | 6.6 |
| Hydro | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - | - | - | - | - | - |
| **Total** | **10.1** | **13.2** | **16.3** | **18.9** | **20.7** | **26.7** | **10.5** | **12.2** | **15.7** | **16.7** | **18.0** | **31.4** | **5.5** | **6.9** | **11.0** | **15.2** | **15.3** | **17.9** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 6.8 | 6.8 | 6.2 | 6.2 | 6.2 | 6.2 | 2.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 5.7 | 5.7 | 5.3 | 5.3 | 5.3 | 5.3 |
| NG | 5.7 | 5.7 | 6.0 | 5.8 | 5.8 | 5.8 | 4.5 | 5.8 | 5.8 | 9.4 | 10.0 | 10.0 | 16.7 | 16.7 | 15.7 | 10.2 | 14.0 | 14.5 |
| Nuclear | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | - | 0.2 | 1.0 | 1.0 | 1.0 | 7.8 | 0.3 | 0.4 | 1.0 | 1.0 | 4.2 | 13.3 | 0.1 | 0.8 | 3.0 | 3.0 | 9.3 | 19.2 |
| 2-Hour Storage | - | - | - | - | 1.2 | 1.2 | - | - | - | - | 0.8 | 0.8 | 0.1 | 0.1 | 0.1 | 5.0 | 5.0 | 5.0 |
| 4-Hour Storage | - | - | 1.2 | 1.2 | 1.2 | 1.2 | - | - | 0.7 | 0.7 | 0.7 | 2.2 | - | - | 2.4 | 2.4 | 2.4 | 2.4 |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | 2.3 | - | - | - | - | - | 2.9 |
| Onshore Wind | 5.8 | 6.2 | 8.8 | 8.8 | 8.8 | 8.8 | 4.6 | 4.7 | 5.7 | 5.7 | 5.7 | 5.7 | 12.6 | 13.4 | 16.9 | 16.9 | 16.9 | 16.9 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total** | **20.5** | **21.0** | **25.3** | **25.1** | **26.4** | **33.2** | **11.5** | **11.9** | **14.2** | **17.8** | **22.4** | **35.4** | **38.0** | **39.4** | **46.2** | **45.4** | **55.6** | **68.9** |

# Zonal Capacity—Scenario B1 (GW)

| Carbon Free Resource Shares | | Moderate | High |
|---|---|---|---|
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 2.1 | 2.1 | 2.1 | 2.1 | 1.2 | 0.6 | 3.8 | 3.8 | 3.5 | 3.5 | 1.7 | 0.9 | 0.4 | 0.4 | 0.4 | 0.4 | - | - |
| NG | 1.6 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.0 | 2.6 | 2.6 | 2.5 | 2.5 | 2.5 | 1.0 | 1.0 | 1.0 | 0.6 | 0.6 | 0.6 |
| Nuclear | - | - | - | - | - | - | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | - | - | - | - | - | - |
| Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.1 | 0.7 | 0.7 | 2.1 | 11.3 | - | 0.1 | 1.1 | 1.3 | 5.6 | 12.1 | - | 0.2 | 1.2 | 1.2 | 3.8 | 4.5 |
| 2-Hour Storage | - | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | - | - | - | - | - | - | - | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 |
| 4-Hour Storage | - | - | 0.7 | 1.1 | 1.1 | 1.1 | - | - | 1.0 | 1.4 | 1.4 | 1.4 | - | - | 0.6 | 0.6 | 0.6 | 0.6 |
| 8-Hour Storage | - | - | - | 0.3 | 0.4 | 2.5 | - | - | - | 0.4 | 2.1 | 5.0 | - | - | - | 0.5 | 2.2 | 2.2 |
| Onshore Wind | 3.5 | 4.7 | 6.5 | 7.5 | 7.9 | 9.0 | 3.5 | 4.4 | 6.7 | 14.8 | 14.8 | 14.8 | 4.2 | 4.2 | 6.6 | 6.7 | 6.7 | 6.7 |
| Hydro | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - | - | - | - | - | - |
| **Total** | **10.1** | **12.7** | **15.7** | **17.4** | **18.3** | **30.1** | **10.5** | **12.2** | **16.2** | **25.0** | **29.3** | **38.0** | **5.5** | **6.8** | **10.9** | **11.0** | **15.0** | **15.6** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 6.8 | 6.8 | 6.2 | 1.4 | - | - | 2.1 | 1.1 | 1.1 | 1.1 | - | - | 5.7 | 5.7 | 5.3 | 3.4 | 2.2 | 2.2 |
| NG | 5.7 | 5.7 | 6.0 | 5.8 | 5.8 | 5.8 | 4.5 | 5.8 | 5.8 | 4.3 | 4.3 | 4.3 | 16.7 | 16.7 | 15.7 | 9.4 | 9.4 | 9.4 |
| Nuclear | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | - | 0.2 | 1.0 | 3.6 | 6.1 | 15.9 | 0.3 | 0.5 | 3.1 | 7.5 | 15.3 | 26.9 | 0.1 | 0.8 | 3.0 | 9.8 | 14.5 | 24.7 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.1 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| 4-Hour Storage | - | - | 1.2 | 1.6 | 1.6 | 1.6 | - | - | 0.7 | 2.2 | 2.2 | 2.2 | - | - | 2.4 | 6.1 | 6.1 | 6.1 |
| 8-Hour Storage | - | - | - | - | - | 2.0 | - | - | - | 1.4 | 6.1 | 11.2 | - | - | - | - | 1.6 | 5.3 |
| Onshore Wind | 5.8 | 6.2 | 8.8 | 8.8 | 8.8 | 8.8 | 4.6 | 4.7 | 5.7 | 5.7 | 5.7 | 5.7 | 12.6 | 13.4 | 16.9 | 16.9 | 16.9 | 16.9 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total** | **20.5** | **21.0** | **25.3** | **23.3** | **24.5** | **36.2** | **11.5** | **12.0** | **16.3** | **22.1** | **33.7** | **50.4** | **38.0** | **39.8** | **46.6** | **48.8** | **54.0** | **68.0** |

# Zonal Capacity—Scenario B2 (GW)

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.8 | 3.8 | 3.5 | 3.5 | 3.2 | 3.2 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| NG | 1.6 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.0 | 2.6 | 2.6 | 2.5 | 2.5 | 2.7 | 1.0 | 1.0 | 1.0 | 4.1 | 4.1 | 5.1 |
| Nuclear | - | - | - | - | - | - | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | - | - | - | - | - | - |
| Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.1 | 0.7 | 0.7 | 2.9 | 11.5 | - | 0.1 | 1.1 | 1.1 | 4.6 | 9.6 | - | 0.2 | 1.2 | 1.2 | 4.0 | 5.9 |
| 2-Hour Storage | - | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | - | - | - | - | - | - | - | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| 4-Hour Storage | - | - | 0.7 | 0.8 | 0.8 | 0.8 | - | - | 1.0 | 1.0 | 1.0 | 1.0 | - | - | 0.6 | 0.6 | 0.6 | 0.6 |
| 8-Hour Storage | - | - | - | 1.1 | 1.2 | 2.6 | - | - | - | 2.6 | 2.6 | 4.4 | - | - | - | 0.3 | 2.1 | 2.6 |
| Onshore Wind | 3.5 | 4.7 | 6.5 | 9.3 | 9.3 | 11.2 | 3.5 | 4.4 | 8.3 | 18.5 | 18.5 | 18.5 | 4.2 | 4.2 | 6.6 | 6.7 | 6.7 | 6.7 |
| Hydro | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - | - | - | - | - | - |
| **Total** | **10.1** | **13.4** | **16.5** | **20.5** | **22.8** | **34.6** | **10.5** | **12.2** | **17.8** | **30.4** | **33.6** | **40.5** | **5.5** | **7.0** | **11.0** | **14.5** | **19.1** | **22.6** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 6.8 | 6.8 | 6.2 | 2.4 | 0.6 | 0.6 | 2.1 | 1.1 | 1.1 | 1.1 | 0.4 | 0.4 | 5.7 | 5.7 | 5.3 | 5.3 | 4.4 | 4.4 |
| NG | 5.7 | 5.7 | 6.0 | 5.8 | 5.8 | 5.8 | 4.5 | 5.8 | 5.8 | 4.3 | 4.3 | 4.3 | 16.7 | 16.7 | 15.7 | 9.4 | 9.4 | 9.4 |
| Nuclear | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | - | 0.2 | 1.0 | 4.4 | 7.8 | 17.9 | 0.3 | 0.5 | 3.3 | 9.0 | 18.7 | 35.0 | 0.1 | 0.8 | 3.0 | 10.1 | 19.6 | 28.5 |
| 2-Hour Storage | - | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | - | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| 4-Hour Storage | - | - | 1.2 | 1.2 | 2.7 | 2.7 | - | - | 0.7 | 2.1 | 2.1 | 2.1 | - | - | 2.4 | 5.7 | 5.7 | 5.7 |
| 8-Hour Storage | - | - | - | - | 0.4 | 2.7 | - | - | - | 2.3 | 7.8 | 15.2 | - | - | - | 0.4 | 4.1 | 6.6 |
| Onshore Wind | 5.8 | 6.2 | 8.8 | 8.8 | 8.8 | 8.8 | 4.6 | 4.7 | 5.7 | 5.7 | 5.7 | 5.7 | 12.6 | 13.4 | 16.9 | 16.9 | 17.2 | 17.5 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total** | **20.5** | **21.7** | **25.9** | **25.4** | **28.8** | **41.3** | **11.5** | **12.4** | **16.9** | **24.8** | **39.5** | **63.2** | **38.0** | **39.4** | **46.2** | **50.7** | **63.3** | **75.0** |

# Zonal Capacity—Scenario B3 (GW)

| Carbon Free Resource Shares | | Moderate | High |
|---|---|---|---|
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 3.8 | 3.8 | 3.5 | 3.5 | 3.5 | 3.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| NG | 1.6 | 2.1 | 2.1 | 3.7 | 5.0 | 5.0 | 2.0 | 2.6 | 2.6 | 5.1 | 5.3 | 5.8 | 1.0 | 1.0 | 1.0 | 6.3 | 6.3 | 7.1 |
| Nuclear | - | - | - | - | - | - | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | - | - | - | - | - | - |
| Oil | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.1 | 0.7 | 0.7 | 4.8 | 15.5 | - | 0.1 | 1.1 | 1.1 | 3.1 | 9.1 | - | 0.2 | 1.2 | 1.2 | 4.4 | 7.8 |
| 2-Hour Storage | - | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| 4-Hour Storage | - | - | 0.7 | 0.7 | 0.7 | 0.7 | - | - | 1.0 | 1.0 | 1.0 | 1.0 | - | - | 0.6 | 0.6 | 0.6 | 0.6 |
| 8-Hour Storage | - | - | - | 1.5 | 2.4 | 4.7 | - | - | - | 2.0 | 2.3 | 3.6 | - | - | - | 0.5 | 2.2 | 3.5 |
| Onshore Wind | 3.5 | 4.7 | 6.6 | 11.3 | 14.1 | 16.5 | 3.5 | 4.4 | 9.4 | 21.8 | 21.8 | 21.8 | 4.2 | 4.2 | 6.6 | 8.0 | 8.0 | 8.0 |
| Hydro | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - | - | - | - | - | - |
| **Total** | **10.1** | **13.2** | **16.4** | **24.2** | **33.2** | **48.7** | **10.5** | **12.2** | **18.8** | **35.7** | **38.2** | **46.0** | **5.5** | **6.7** | **10.7** | **18.0** | **22.8** | **28.4** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 6.8 | 6.8 | 6.2 | 3.6 | 3.6 | 3.6 | 2.1 | 1.1 | 1.1 | 1.1 | 0.4 | 0.4 | 5.7 | 5.7 | 5.3 | 5.3 | 5.3 | 5.3 |
| NG | 5.7 | 5.7 | 6.0 | 5.8 | 5.8 | 7.3 | 4.5 | 5.8 | 5.8 | 5.5 | 5.5 | 7.0 | 16.7 | 16.7 | 15.7 | 12.1 | 13.6 | 15.5 |
| Nuclear | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Solar | - | 0.2 | 1.0 | 5.6 | 12.6 | 29.4 | 0.3 | 0.4 | 3.3 | 9.0 | 24.7 | 38.4 | 0.1 | 0.8 | 3.0 | 10.7 | 24.6 | 30.6 |
| 2-Hour Storage | - | 1.2 | 1.5 | 1.5 | 1.5 | 1.5 | - | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.1 | 0.7 | 1.5 | 1.5 | 1.5 | 1.5 |
| 4-Hour Storage | - | - | 1.2 | 1.2 | 1.2 | 1.2 | - | - | 0.7 | 1.1 | 1.1 | 1.1 | - | - | 2.4 | 3.8 | 3.8 | 3.8 |
| 8-Hour Storage | - | - | - | - | 4.9 | 9.3 | - | - | - | 2.5 | 11.2 | 17.3 | - | - | - | 2.8 | 6.5 | 7.2 |
| Onshore Wind | 5.8 | 6.2 | 8.8 | 8.8 | 10.2 | 10.2 | 4.6 | 4.7 | 6.3 | 6.3 | 6.3 | 6.3 | 12.6 | 13.4 | 16.9 | 17.6 | 18.4 | 19.5 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| **Total** | **20.5** | **22.2** | **26.8** | **28.7** | **42.0** | **64.6** | **11.5** | **12.4** | **17.6** | **26.0** | **49.7** | **71.0** | **38.0** | **39.9** | **47.5** | **56.5** | **76.3** | **86.0** |

# SPP Generation—All Scenarios (TWh)

| Carbon Free Resource Shares | | Moderate | High |
|---|---|---|---|
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

| | Scenario A1 | | | | | | Scenario A2 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 60.9 | 87.5 | 82.7 | 78.4 | 89.7 | 99.6 | 60.1 | 87.5 | 86.9 | 85.9 | 101.0 | 106.6 |
| NG | 72.2 | 49.6 | 34.9 | 52.8 | 44.2 | 38.9 | 71.7 | 49.3 | 37.0 | 70.7 | 68.7 | 50.2 |
| Nuclear | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.9 | 3.8 | 18.4 | 18.7 | 35.4 | 98.9 | 0.9 | 3.9 | 18.5 | 18.7 | 42.0 | 126.1 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 126.5 | 138.8 | 186.8 | 187.9 | 187.8 | 196.7 | 126.5 | 139.0 | 187.4 | 188.1 | 188.7 | 215.6 |
| Hydro | 17.6 | 17.6 | 17.6 | 17.8 | 17.8 | 17.6 | 17.6 | 17.6 | 17.7 | 17.8 | 17.8 | 17.6 |
| **Total** | **295.5** | **314.6** | **357.7** | **372.9** | **392.2** | **469.0** | **294.2** | **314.6** | **364.8** | **398.4** | **435.4** | **533.4** |

| | Scenario B1 | | | | | | Scenario B2 | | | | | | Scenario B3 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 60.9 | 87.0 | 79.3 | 44.3 | 20.7 | 15.4 | 60.1 | 87.2 | 80.5 | 51.6 | 40.6 | 40.7 | 59.2 | 87.4 | 82.9 | 59.9 | 54.4 | 52.8 |
| NG | 72.2 | 49.3 | 32.9 | 34.3 | 31.6 | 24.5 | 71.7 | 49.1 | 34.4 | 34.0 | 24.0 | 15.9 | 71.2 | 49.0 | 36.3 | 40.1 | 23.0 | 17.1 |
| Nuclear | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 | 17.3 |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.9 | 4.3 | 24.1 | 57.1 | 112.8 | 217.6 | 0.9 | 4.2 | 24.6 | 63.6 | 137.5 | 249.3 | 0.9 | 4.1 | 24.5 | 67.8 | 176.2 | 298.6 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 126.5 | 139.2 | 189.7 | 222.5 | 222.9 | 220.8 | 126.5 | 139.3 | 195.7 | 242.6 | 242.2 | 243.2 | 126.5 | 139.2 | 202.6 | 272.0 | 286.9 | 291.9 |
| Hydro | 17.6 | 17.5 | 16.9 | 15.1 | 14.1 | 11.4 | 17.6 | 17.6 | 17.0 | 15.2 | 14.5 | 11.6 | 17.6 | 17.6 | 17.0 | 15.3 | 14.4 | 11.5 |
| **Total** | **295.5** | **314.6** | **360.3** | **390.6** | **419.3** | **507.1** | **294.2** | **314.5** | **369.4** | **424.3** | **476.1** | **577.9** | **292.7** | **314.6** | **380.7** | **472.3** | **572.3** | **689.3** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

# Zonal Generation—Scenario A1 (TWh)

| | Carbon Free Resource Shares | |
|---|---|---|
| Electrification | Moderate | High |
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 11.6 | 12.1 | 12.1 | 12.5 | 13.1 | 13.5 | 17.5 | 21.4 | 18.2 | 19.1 | 20.5 | 20.6 | 0.5 | 0.9 | 1.1 | 1.0 | 1.4 | 1.8 |
| NG | 2.0 | 1.1 | 0.6 | 0.5 | 0.5 | 0.6 | 2.0 | 1.3 | 0.9 | 0.9 | 0.8 | 0.7 | 0.6 | 0.3 | 0.1 | 0.2 | 0.3 | 3.4 |
| Nuclear | - | - | - | - | - | - | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.3 | 1.5 | 1.5 | 1.5 | 5.3 | 0.1 | 0.2 | 2.5 | 2.6 | 2.6 | 13.3 | - | 0.5 | 2.9 | 3.1 | 3.1 | 4.4 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 12.6 | 16.7 | 23.3 | 23.4 | 23.3 | 23.7 | 13.0 | 16.4 | 23.0 | 23.2 | 23.2 | 33.1 | 15.1 | 15.3 | 23.8 | 24.3 | 24.4 | 24.0 |
| Hydro | 9.6 | 9.6 | 9.6 | 9.7 | 9.7 | 9.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | - | - | - | - | - | - |
| **Total** | **35.8** | **39.8** | **47.1** | **47.6** | **48.2** | **52.8** | **40.1** | **46.7** | **52.1** | **53.1** | **54.4** | **75.2** | **16.2** | **17.0** | **28.0** | **28.6** | **29.1** | **33.6** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 17.7 | 28.2 | 25.9 | 22.7 | 26.4 | 29.4 | 4.5 | 4.9 | 5.2 | 3.8 | 4.7 | 5.6 | 9.2 | 19.9 | 20.1 | 19.3 | 23.6 | 28.6 |
| NG | 11.8 | 8.1 | 6.0 | 6.9 | 5.7 | 4.8 | 14.0 | 9.7 | 7.0 | 21.8 | 18.7 | 13.3 | 41.7 | 29.0 | 20.3 | 22.6 | 18.2 | 16.1 |
| Nuclear | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.1 | 0.4 | 2.2 | 2.2 | 2.2 | 16.9 | 0.5 | 0.8 | 2.4 | 2.4 | 11.0 | 26.3 | 0.2 | 1.7 | 6.9 | 6.9 | 15.0 | 32.6 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 21.1 | 22.4 | 31.8 | 31.8 | 31.8 | 31.7 | 17.9 | 18.3 | 22.1 | 22.2 | 22.1 | 21.8 | 46.9 | 49.8 | 62.8 | 63.0 | 63.0 | 62.5 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 7.3 | 7.3 | 7.2 | 7.3 | 7.3 | 7.2 |
| **Total** | **61.3** | **69.6** | **76.5** | **74.2** | **76.8** | **93.3** | **36.9** | **33.7** | **36.7** | **50.1** | **56.6** | **67.0** | **105.2** | **107.8** | **117.3** | **119.2** | **127.2** | **147.0** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

# Zonal Generation—Scenario A2 (TWh)

| | | Carbon Free Resource Shares | |
|---|---|---|---|
| | | Moderate | High |
| Electrification | Low | A1 | B1 |
| | Moderate | A2 | B2 |
| | High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 11.5 | 12.2 | 12.5 | 13.5 | 14.2 | 13.8 | 17.4 | 21.4 | 19.0 | 20.2 | 22.6 | 20.4 | 0.5 | 1.0 | 1.3 | 1.2 | 1.7 | 1.9 |
| NG | 2.0 | 1.0 | 0.7 | 0.7 | 0.7 | 0.9 | 2.0 | 1.3 | 1.0 | 1.1 | 0.9 | 0.7 | 0.6 | 0.2 | 0.2 | 0.8 | 1.1 | 0.8 |
| Nuclear | - | - | - | - | - | - | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.3 | 1.5 | 1.5 | 1.5 | 10.8 | 0.1 | 0.2 | 2.5 | 2.6 | 2.6 | 13.1 | - | 0.5 | 3.0 | 3.1 | 3.1 | 7.0 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 12.6 | 16.7 | 23.4 | 23.4 | 23.4 | 26.8 | 13.0 | 16.4 | 23.1 | 23.2 | 23.8 | 48.7 | 15.1 | 15.4 | 24.1 | 24.5 | 24.5 | 24.1 |
| Hydro | 9.6 | 9.6 | 9.7 | 9.8 | 9.8 | 9.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | - | - | - | - | - | - |
| **Total** | **35.7** | **39.9** | **47.8** | **49.0** | **49.7** | **62.0** | **39.9** | **46.7** | **53.0** | **54.5** | **57.3** | **90.3** | **16.2** | **17.1** | **28.5** | **29.6** | **30.4** | **33.8** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 17.4 | 28.1 | 27.4 | 27.3 | 32.7 | 34.7 | 4.5 | 4.9 | 5.3 | 3.4 | 5.0 | 5.8 | 8.9 | 19.9 | 21.5 | 20.3 | 24.9 | 30.0 |
| NG | 11.8 | 8.2 | 6.3 | 7.2 | 6.0 | 3.7 | 13.9 | 9.6 | 7.5 | 33.2 | 28.9 | 18.7 | 41.4 | 29.1 | 21.3 | 27.6 | 31.1 | 25.4 |
| Nuclear | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.1 | 0.4 | 2.2 | 2.2 | 2.2 | 17.6 | 0.5 | 0.8 | 2.4 | 2.4 | 10.8 | 33.6 | 0.2 | 1.7 | 6.9 | 6.9 | 21.8 | 44.0 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 21.1 | 22.4 | 31.8 | 31.8 | 31.8 | 31.7 | 17.9 | 18.3 | 22.1 | 22.2 | 22.2 | 21.9 | 46.9 | 49.8 | 62.8 | 63.0 | 63.0 | 62.4 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 7.3 | 7.3 | 7.3 | 7.4 | 7.4 | 7.3 |
| **Total** | **60.9** | **69.5** | **78.3** | **79.1** | **83.2** | **98.3** | **36.7** | **33.5** | **37.3** | **61.1** | **66.8** | **80.0** | **104.6** | **107.8** | **119.9** | **125.2** | **148.1** | **169.0** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

| Carbon Free Resource Shares | | |
|---|---|---|
| **Electrification** | **Moderate** | **High** |
| **Low** | A1 | B1 |
| **Moderate** | A2 | B2 |
| **High** | | B3 |



# Zonal Generation—Scenario B1 (TWh)

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 11.6 | 12.1 | 11.9 | 9.7 | 5.5 | 2.4 | 17.5 | 21.2 | 17.6 | 13.5 | 6.9 | 3.6 | 0.5 | 0.9 | 1.1 | 1.1 | - | - |
| NG | 2.0 | 1.1 | 0.5 | 0.4 | 0.4 | 0.4 | 2.0 | 1.3 | 0.7 | 0.7 | 0.8 | 0.6 | 0.6 | 0.2 | 0.1 | 0.2 | 0.3 | 0.2 |
| Nuclear | - | - | - | - | - | - | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.3 | 1.5 | 1.5 | 4.7 | 24.2 | 0.1 | 0.2 | 2.6 | 2.9 | 12.8 | 27.3 | - | 0.5 | 3.1 | 3.0 | 9.2 | 10.1 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 12.6 | 16.8 | 23.4 | 27.0 | 28.3 | 32.0 | 13.0 | 16.5 | 25.0 | 54.8 | 54.7 | 53.0 | 15.1 | 15.4 | 24.3 | 24.2 | 24.2 | 23.2 |
| Hydro | 9.6 | 9.5 | 9.3 | 8.3 | 7.6 | 6.1 | 0.7 | 0.7 | 0.6 | 0.6 | 0.5 | 0.4 | - | - | - | - | - | - |
| **Total** | **35.8** | **39.9** | **46.7** | **46.9** | **46.4** | **65.1** | **40.1** | **46.6** | **53.3** | **79.2** | **82.3** | **91.6** | **16.2** | **17.1** | **28.6** | **28.4** | **33.6** | **33.6** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 17.7 | 28.0 | 25.1 | 5.6 | - | - | 4.5 | 4.9 | 4.4 | 3.4 | - | - | 9.2 | 19.8 | 19.1 | 11.0 | 8.3 | 9.4 |
| NG | 11.8 | 8.2 | 6.0 | 6.2 | 5.8 | 4.6 | 14.0 | 9.5 | 6.0 | 6.3 | 5.3 | 3.5 | 41.7 | 29.0 | 19.6 | 20.6 | 19.2 | 15.3 |
| Nuclear | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.1 | 0.4 | 2.2 | 8.1 | 13.8 | 34.5 | 0.5 | 1.1 | 7.8 | 19.0 | 39.2 | 65.6 | 0.2 | 1.7 | 6.9 | 22.6 | 33.1 | 55.9 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 21.1 | 22.4 | 31.8 | 31.8 | 31.7 | 31.1 | 17.9 | 18.3 | 22.2 | 22.0 | 21.6 | 19.8 | 46.9 | 49.8 | 63.0 | 62.7 | 62.5 | 61.7 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 7.3 | 7.3 | 7.0 | 6.3 | 6.0 | 4.9 |
| **Total** | **61.3** | **69.5** | **75.7** | **62.2** | **61.9** | **80.7** | **36.9** | **33.8** | **40.4** | **50.7** | **66.1** | **88.9** | **105.2** | **107.6** | **115.6** | **123.1** | **129.0** | **147.2** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

# Zonal Generation—Scenario B2 (TWh)

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| | North | | | | | | North Central | | | | | | Central West | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 11.5 | 12.2 | 12.1 | 9.5 | 8.8 | 8.3 | 17.4 | 21.2 | 16.5 | 13.0 | 12.0 | 11.1 | 0.5 | 1.0 | 1.2 | 1.1 | 1.1 | 1.2 |
| NG | 2.0 | 1.0 | 0.6 | 0.3 | 0.3 | 0.3 | 2.0 | 1.3 | 0.8 | 0.6 | 0.4 | 0.4 | 0.6 | 0.2 | 0.2 | 0.4 | 0.5 | 0.4 |
| Nuclear | - | - | - | - | - | - | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | - | 0.3 | 1.5 | 1.5 | 6.4 | 24.7 | 0.1 | 0.2 | 2.6 | 2.5 | 10.6 | 21.3 | - | 0.6 | 3.1 | 3.0 | 9.6 | 13.2 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 12.6 | 16.8 | 23.4 | 33.6 | 33.6 | 39.7 | 13.0 | 16.5 | 31.0 | 68.0 | 67.9 | 66.0 | 15.1 | 15.4 | 24.3 | 24.4 | 24.3 | 23.3 |
| Hydro | 9.6 | 9.6 | 9.3 | 8.3 | 7.9 | 6.2 | 0.7 | 0.7 | 0.6 | 0.6 | 0.5 | 0.4 | - | - | - | - | - | - |
| **Total** | **35.7** | **40.0** | **47.1** | **53.2** | **57.0** | **79.1** | **39.9** | **46.6** | **58.1** | **91.3** | **98.1** | **106.0** | **16.2** | **17.2** | **28.8** | **28.9** | **35.5** | **38.1** |

| | Central East | | | | | | Southwest | | | | | | Southeast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
| BioGen | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal | 17.4 | 27.9 | 25.7 | 9.2 | 2.2 | 2.1 | 4.5 | 4.9 | 4.6 | 3.3 | 1.5 | 1.6 | 8.9 | 20.0 | 20.3 | 15.6 | 15.0 | 16.4 |
| NG | 11.8 | 8.1 | 6.2 | 6.0 | 4.7 | 2.6 | 13.9 | 9.4 | 6.1 | 6.0 | 3.7 | 1.5 | 41.4 | 29.0 | 20.5 | 20.7 | 14.5 | 10.8 |
| Nuclear | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | - | - | - | - | - | - | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Solar | 0.1 | 0.4 | 2.2 | 10.1 | 17.8 | 40.0 | 0.5 | 1.0 | 8.3 | 23.0 | 48.0 | 84.6 | 0.2 | 1.7 | 6.9 | 23.4 | 45.2 | 65.4 |
| 2-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Onshore Wind | 21.1 | 22.4 | 31.8 | 31.8 | 31.8 | 31.2 | 17.9 | 18.3 | 22.2 | 22.0 | 21.6 | 19.7 | 46.9 | 49.8 | 63.0 | 62.9 | 63.1 | 63.3 |
| Hydro | - | - | - | - | - | - | - | - | - | - | - | - | 7.3 | 7.3 | 7.0 | 6.3 | 6.0 | 4.9 |
| **Total** | **60.9** | **69.4** | **76.5** | **67.6** | **67.0** | **86.5** | **36.7** | **33.6** | **41.2** | **54.3** | **74.7** | **107.4** | **104.6** | **107.8** | **117.7** | **128.9** | **143.9** | **160.9** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

# Zonal Generation—Scenario B3 (TWh)

| Electrification | Carbon Free Resource Shares: Moderate | Carbon Free Resource Shares: High |
|---|---|---|
| Low | A1 | B1 |
| Moderate | A2 | B2 |
| High | | B3 |

| North | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 11.4 | 12.3 | 12.5 | 10.3 | 9.0 | 8.0 |
| NG | 1.9 | 1.0 | 0.8 | 0.4 | 0.5 | 0.5 |
| Nuclear | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | - | 0.3 | 1.5 | 1.5 | 10.3 | 33.0 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 12.6 | 16.8 | 23.8 | 40.6 | 50.5 | 57.9 |
| Hydro | 9.6 | 9.6 | 9.4 | 8.4 | 7.9 | 6.3 |
| **Total** | **35.6** | **40.0** | **47.9** | **61.3** | **78.2** | **105.7** |

| North Central | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 17.1 | 21.3 | 16.6 | 13.7 | 12.5 | 11.7 |
| NG | 1.9 | 1.3 | 0.9 | 0.7 | 0.4 | 0.5 |
| Nuclear | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 | 6.7 |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | 0.1 | 0.2 | 2.6 | 2.5 | 7.0 | 20.3 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 13.0 | 16.5 | 35.0 | 79.9 | 79.7 | 77.7 |
| Hydro | 0.7 | 0.7 | 0.6 | 0.6 | 0.5 | 0.4 |
| **Total** | **39.7** | **46.7** | **62.4** | **104.1** | **106.8** | **117.2** |

| Central West | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 0.5 | 0.9 | 1.3 | 1.0 | 1.0 | 1.0 |
| NG | 0.6 | 0.2 | 0.2 | 0.8 | 0.6 | 0.6 |
| Nuclear | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | - | 0.5 | 3.1 | 3.0 | 10.5 | 17.3 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 15.1 | 15.4 | 24.3 | 29.4 | 29.1 | 27.9 |
| Hydro | - | - | - | - | - | - |
| **Total** | **16.2** | **17.1** | **28.9** | **34.3** | **41.2** | **46.9** |

| Central East | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 17.0 | 27.9 | 26.7 | 13.7 | 13.5 | 12.1 |
| NG | 11.7 | 8.2 | 6.4 | 6.3 | 3.6 | 2.5 |
| Nuclear | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 | 10.6 |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | 0.1 | 0.4 | 2.2 | 12.7 | 28.7 | 65.4 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 21.1 | 22.4 | 32.0 | 31.9 | 36.9 | 36.1 |
| Hydro | - | - | - | - | - | - |
| **Total** | **60.5** | **69.4** | **77.9** | **75.2** | **93.2** | **126.7** |

| Southwest | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 4.5 | 4.9 | 4.7 | 3.6 | 1.5 | 1.4 |
| NG | 13.8 | 9.4 | 6.5 | 7.9 | 3.8 | 2.1 |
| Nuclear | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | 0.5 | 0.9 | 8.3 | 23.1 | 63.0 | 92.6 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 17.9 | 18.3 | 24.6 | 24.4 | 23.4 | 21.6 |
| Hydro | - | - | - | - | - | - |
| **Total** | **36.6** | **33.5** | **44.0** | **59.0** | **91.7** | **117.6** |

| Southeast | 2023 | 2025 | 2029 | 2034 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| BioGen | - | - | - | - | - | - |
| Coal | 8.7 | 20.1 | 21.2 | 17.6 | 16.9 | 18.7 |
| NG | 41.2 | 28.9 | 21.6 | 23.9 | 14.1 | 10.9 |
| Nuclear | - | - | - | - | - | - |
| Oil | - | - | - | - | - | - |
| Pumped Storage | - | - | - | - | - | - |
| Solar | 0.2 | 1.7 | 6.9 | 25.0 | 56.8 | 70.0 |
| 2-Hour Storage | - | - | - | - | - | - |
| 4-Hour Storage | - | - | - | - | - | - |
| 8-Hour Storage | - | - | - | - | - | - |
| Onshore Wind | 46.9 | 49.8 | 63.0 | 65.7 | 67.3 | 70.7 |
| Hydro | 7.3 | 7.3 | 7.0 | 6.3 | 6.0 | 4.8 |
| **Total** | **104.2** | **107.8** | **119.6** | **138.4** | **161.0** | **175.1** |

*Note: Generation by zone is sum of generation used to meet internal load plus exports to serve demand located in other regions.*

# Appendix 3

# FERNS Land Use Study

CONTENTS

# APPENDIX 3:
# FERNS Land Use Study

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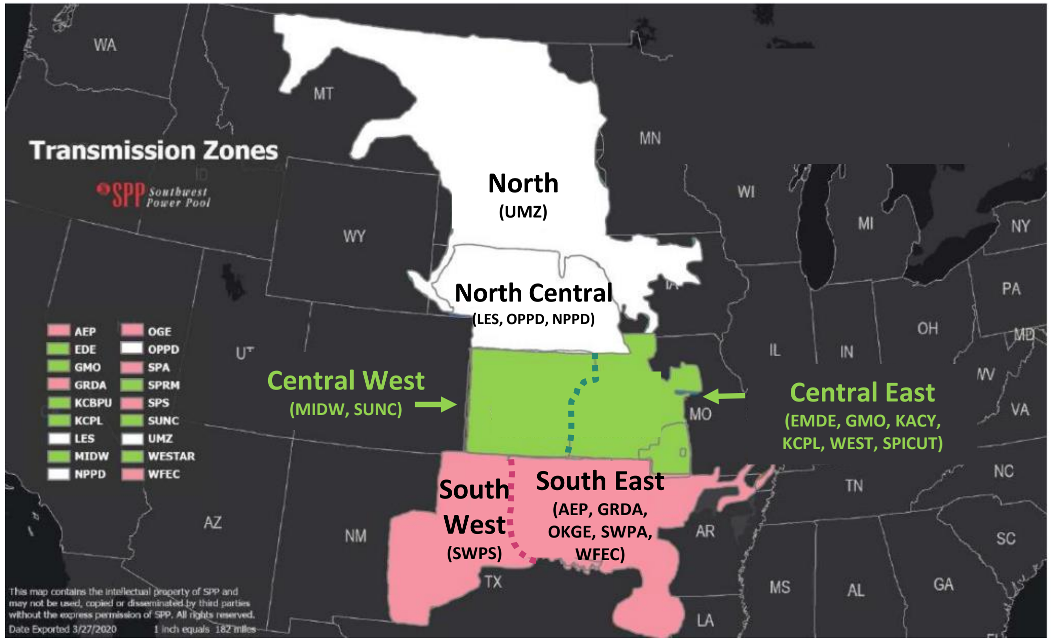
# Land Use Analysis Overview

FERNS capacity expansion modeling results are screened by a land-use analysis to ensure that optimally selected resources are within feasibility limits and reflect interconnection cost thresholds:

- NREL and The Nature Conservancy publish data on land-use feasibility of generation capacity for solar and wind across the entire country.
  - Both consider physical attributes, federal and state land designations, environmental impacts, social impacts, and local regulatory policies.
- FERNS considers land-use impacts on generation feasibility within specific FERNS zones within the SPP footprint.
- Estimated generation potential in each zone is used to screen the modeled renewable generation build-out across scenarios.

Detailed results from the FERNS land use study could be utilized for more detailed node-specific generation analysis in Consolidated Planning Process (CPP) efforts.

**Zones for FERNS Study**

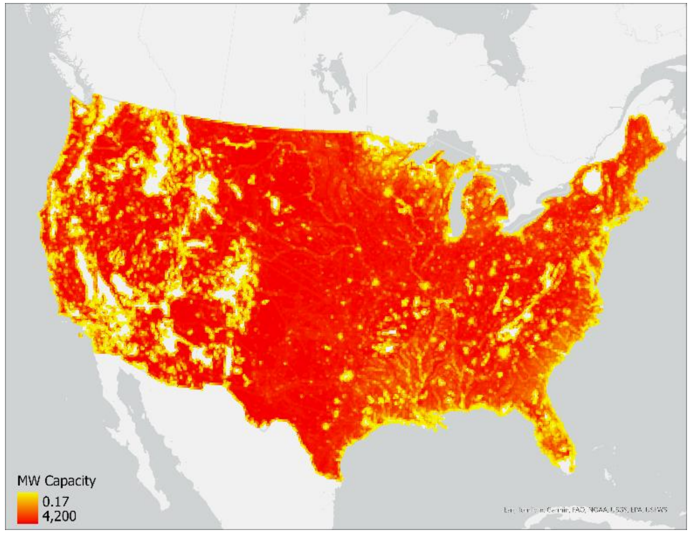


# Data Sources

The FERNS land-use analysis relies on NREL and Nature Conservancy data that respectively estimate generation potential across the country accounting for certain physical land-use considerations and quantify available developable area subject to environmental and social restrictions. Combined, they quantify restrictions and hurdles facing renewable deployment in SPP:

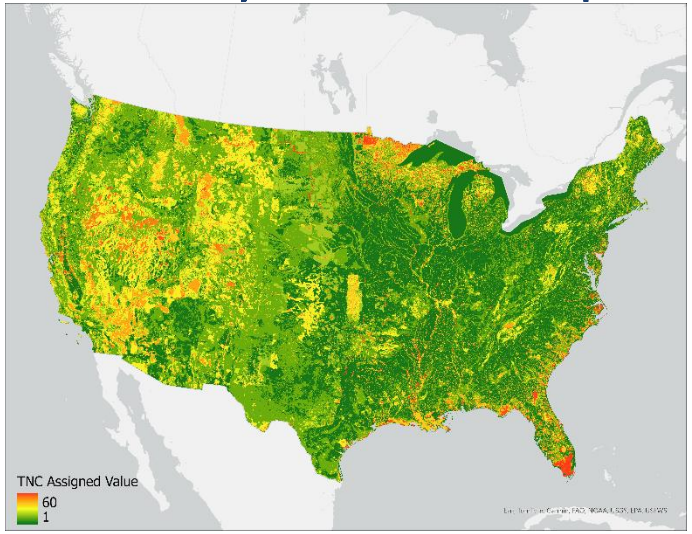
- **NREL Geospatial Data** provides estimates of generation potential across the continental U.S. and incorporates datasets from local, state and federal jurisdictions that account for protected lands, zoning and setback requirements, among other restrictions. NREL provides 3 scenarios of generation potential (open, reference, limited) which vary in building capability land use restrictions.
- **The Nature Conservancy (TNC) Power of Place Data** incorporates environmental and socially driven land use restrictions. Data is reported as a land impact score (1 to 60 for environmental; −10 to 40 for social) for each 250×250 meter square of the U.S. TNC data is synergistic with the NREL data, providing additional development restrictions to supplement NREL's technical potential.

**NREL Solar Generation Capacity (Open Access)**




*Source:* *NREL Solar Supply Curves*

**Nature Conservancy Environmental Impact Estimate**

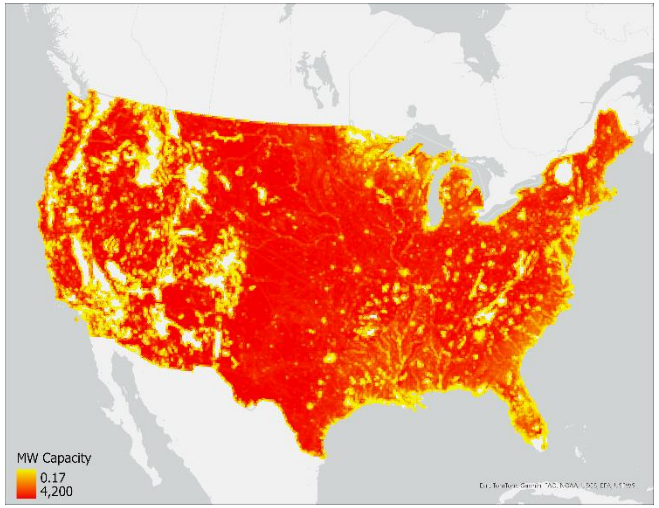



*Source:* *The Nature Conservancy, Power of Place*

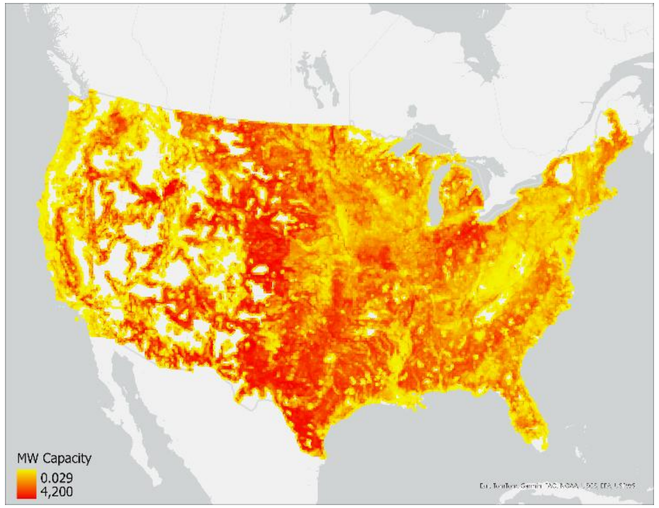
# NREL Data and Assumptions

- The 3 NREL scenarios estimate MW generation potential for each 33.2km$^2$ area of the U.S. after considering varying level of land availability.
  - The “<u>open</u>” scenario removes only physical restrictions such as building footprints and protected federal land.
  - The “<u>reference</u>” scenario is the base assumption used for subsequent NREL analysis and incorporates additional county and local building restrictions.
  - The “<u>limited</u>” scenario considers very limited development potential due to larger setbacks and building limitations.
- FERNS relies on the NREL “reference” scenario for our analysis in combination with TNC land use restrictions and use the “limited” scenario as a sensitivity for very restrictive exclusions.
- We assume that generation potential is evenly distributed throughout each represented 33.2km$^2$ area.

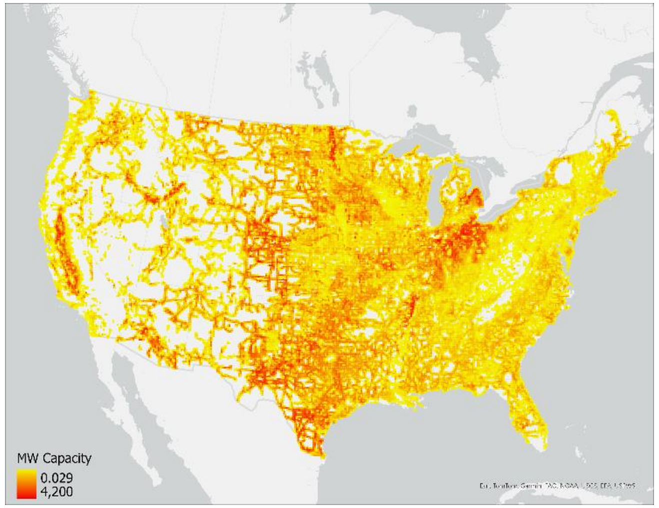
**Solar Example**




**Open**




**Reference**




**Limited**

# TNC Data and Assumptions

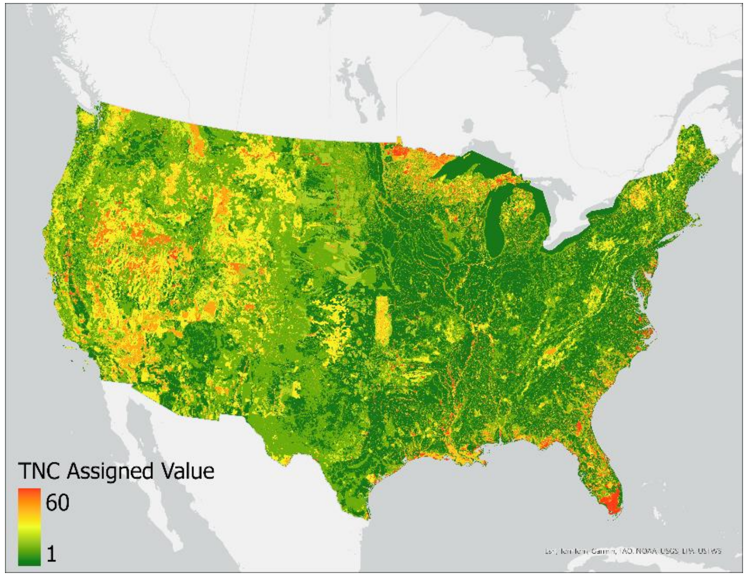
- TNC classifies each 250×250 $m^2$ section of the country into land categories. These include the following (among other categories):

| Environmental | Social |
|---|---|
| Wetlands | Productive and Valuable Farmland |
| Managed Areas | Recreational Areas |
| Threatened & Endangered Habitat | Scenic Areas |
| Intact Habitat | Energy Communities (per IRA) |

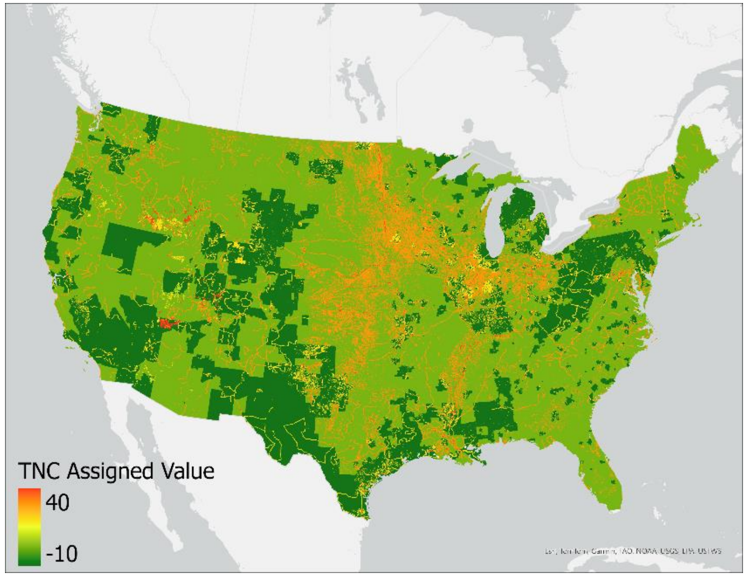
- Each category is assigned a value that signifies development risk. For example, the score for area that is both a wetland and an intact habitat equals the sum for both values. The aggregate values create the scale of impact shown. Low scores signify the best development sites, high scores reflect high impacts (least desirable and likely met with pushback).
- We exclude areas that receive a score higher than 10 on the environmental scale, and 5 on the social scale, but examine other threshold options.

<u>Note</u>: the social impact score can be negative (representing socially beneficial development).

**Environmental**



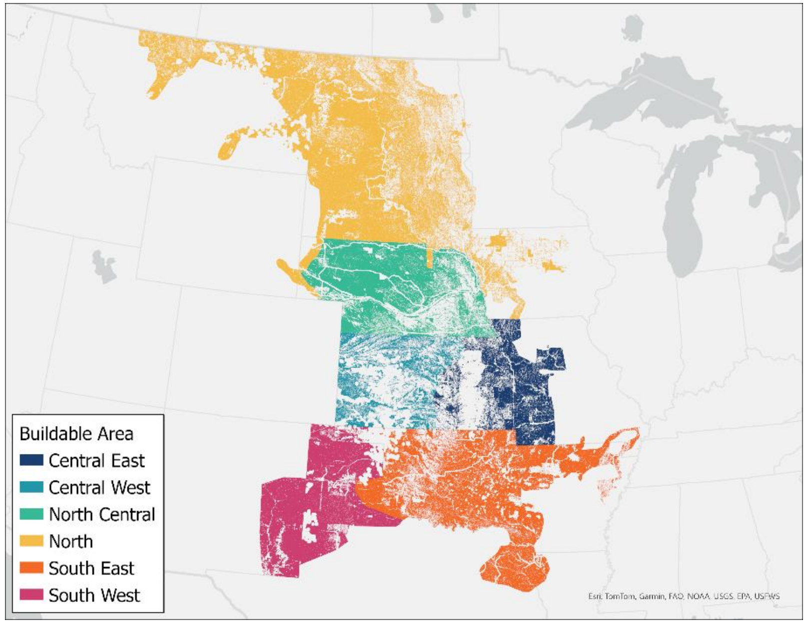

**Social**



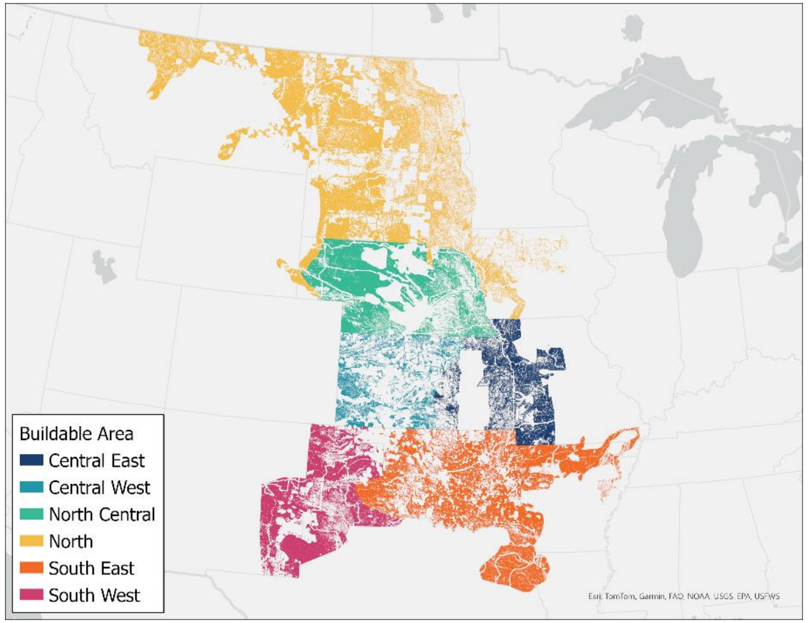
# TNC Thresholds: Solar

**Least Restrictive** → **Most Restrictive**

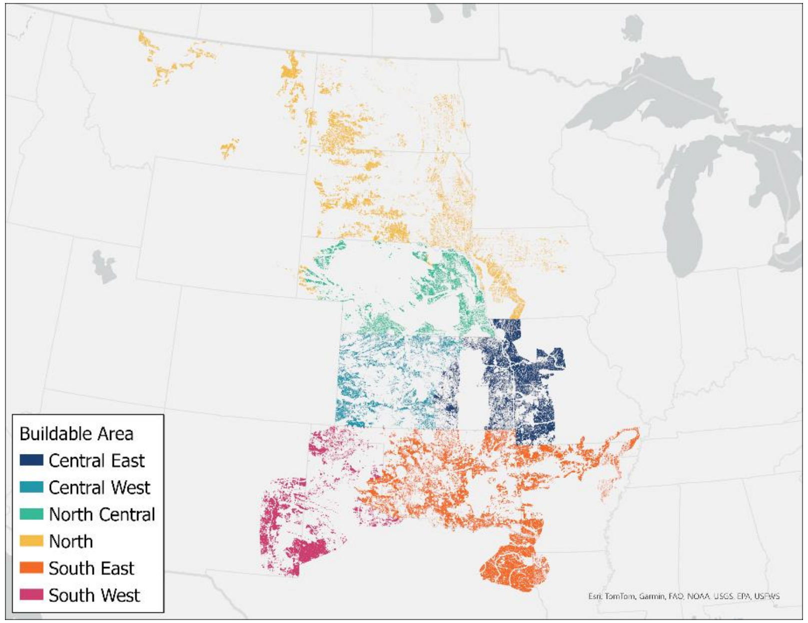
20 Enviro, 10 Social




10 Enviro, 5 Social




5 Enviro, 1 Social



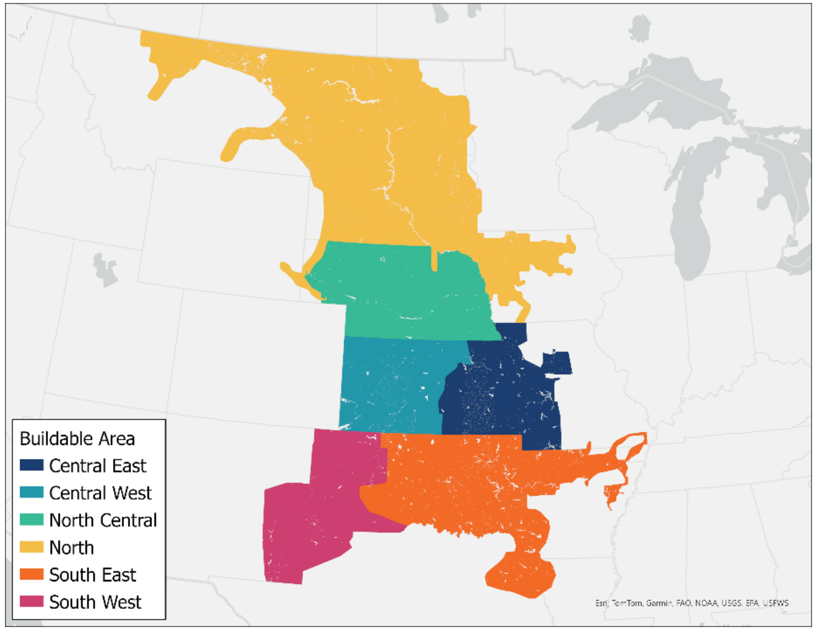

*Threshold of 10 environmental score and 5 social selected for analysis*

- We applied multiple thresholds to the TNC land use scales to determine the amount of buildable land within each FERNS zone in SPP's footprint.
- To be conservative in our analysis we rely on the most restrictive (lowest) thresholds to estimate potential building areas and screen FERNS modeling results.

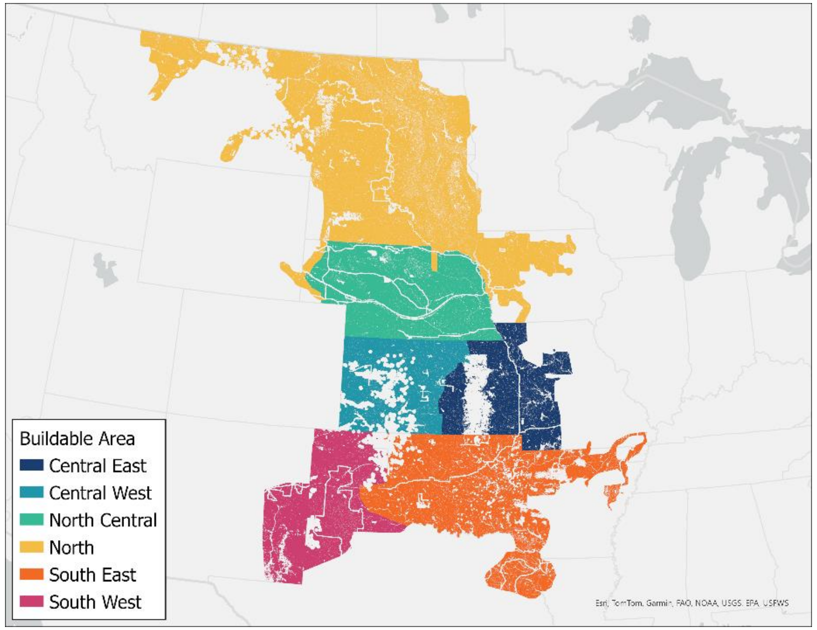
# TNC Thresholds: Wind

**Least Restrictive** → **Most Restrictive**

20 Enviro, 10 Social

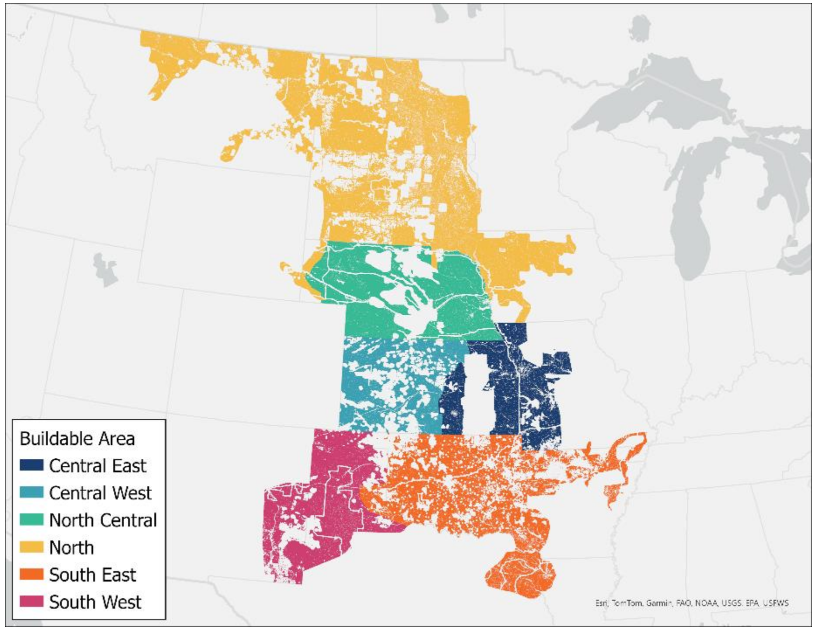



10 Enviro, 5 Social




*Threshold of 10 environmental score and 5 social selected for analysis*

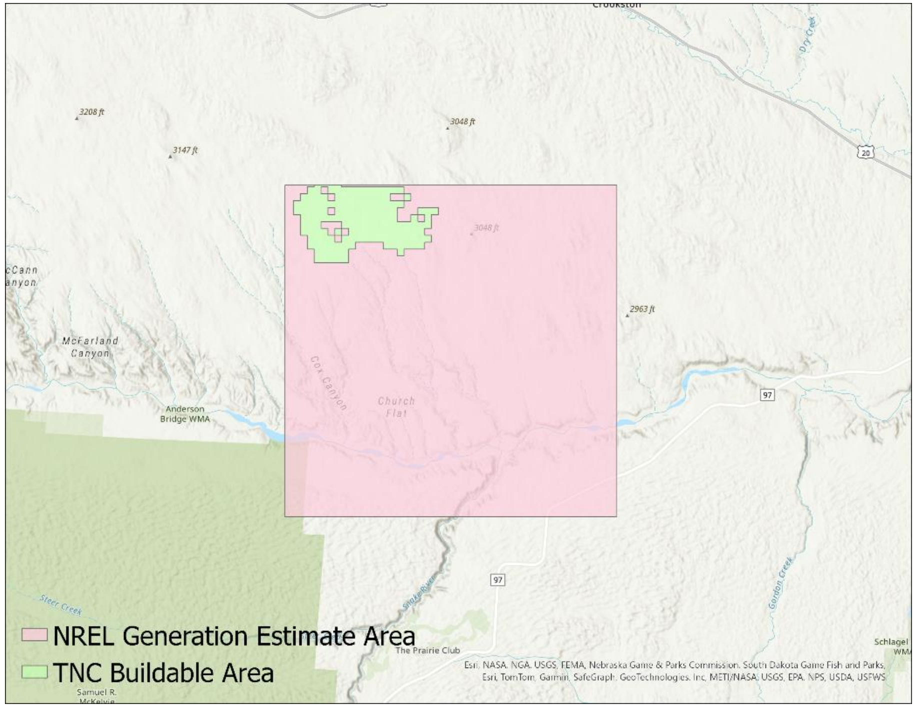
5 Enviro, 1 Social




- Wind has a much more expansive footprint then solar PV, as shown by potential building areas above.
- Note these maps show scores for just the TNC data, before combining with the NREL dataset.

# Combining NREL and TNC Data

1. This FERNS land use analysis starts with considering TNC's data. We filter to areas below the defined threshold for the environmental (10) and social (5) impact. This is the "buildable" (low impact) area.
2. For each square of NREL's data, we consider the estimated MW of capacity as evenly distributed across the 33.2 km$^2$.
3. We overlay the TNC filter calculated in step 1 with the NREL data to consider the portion of each NREL area that is considered "buildable." The resulting value is the MW NREL estimate reduced by the TNC filters to arrive at a TNC-adjusted NREL generation potential for a given area.
4. We apply an additional screen to restrict developable land estimates to only continuous regions with at least 1 square km of buildable land.
5. These estimated values are summed across the FERNS-modeled SPP zones in tables of the next slides.




*The area of the green shape divided by the area of the whole square is multiplied by the MW estimate for that area from NREL. The resulting MW estimate is considered the available generation potential for that area. TNC buildable area shown represents an environmental threshold of 10 and social threshold of 5.*

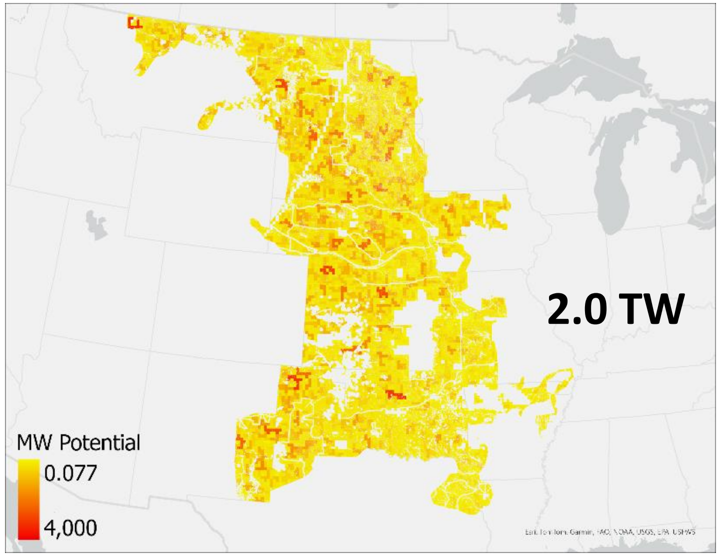
# Generation Potential within NREL+TNC Limited Areas

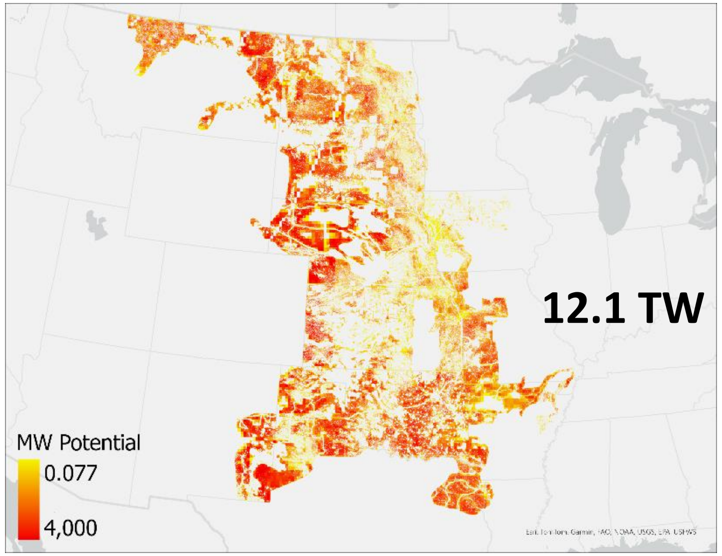
- The maps to the right show generation potential across the SPP footprint by using the "reference" and "limited" NREL datasets and removing TNC determined high-impact areas.
- Across SPP, generation potential is estimated to range between 1.2 TW and 2.0 TW for wind and between 4.7 TW and 12.1 TW for solar.
- Estimates are conservative as they may duplicate removal of certain land exclusions.
  - E.g., Areas of Critical Environmental Concern (US Department of Interior) are excluded from both NREL and TNC data.

Maps show generation potential based on a TNC environmental threshold better than 10 and social threshold better than 5.

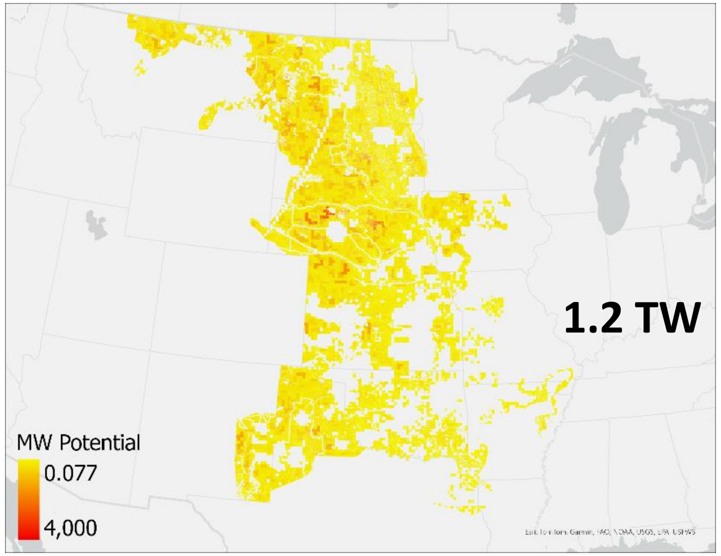
## Wind | Solar PV

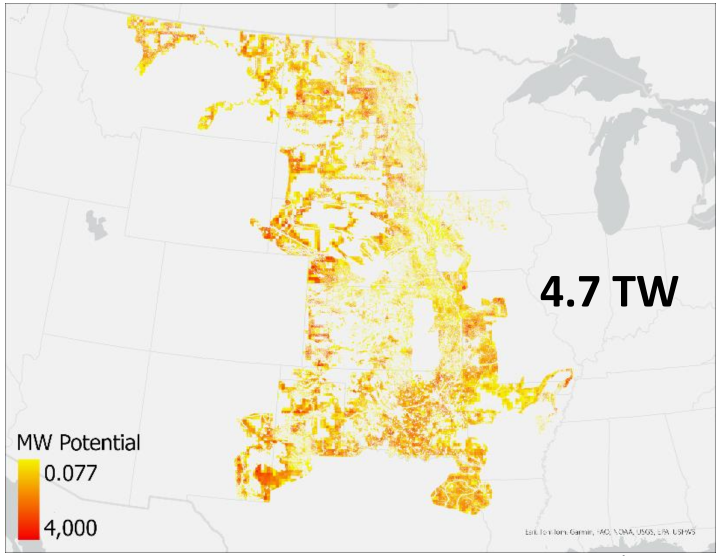
**NREL Reference Access**




**NREL Limited Access**



# Generation Potential Results by FERNS Zone

- Total low-impact generation potential for a single zone exceeds 264 GW (3.3 TW SPP wide) of solar and wind power, even in the most restrictive case shown.
- These estimates consider all land within each zone and do not consider proximity to existing transmission or subs, which would impact the price and ease to install additional capacity.

## Total GW of Generation Capacity by Zone

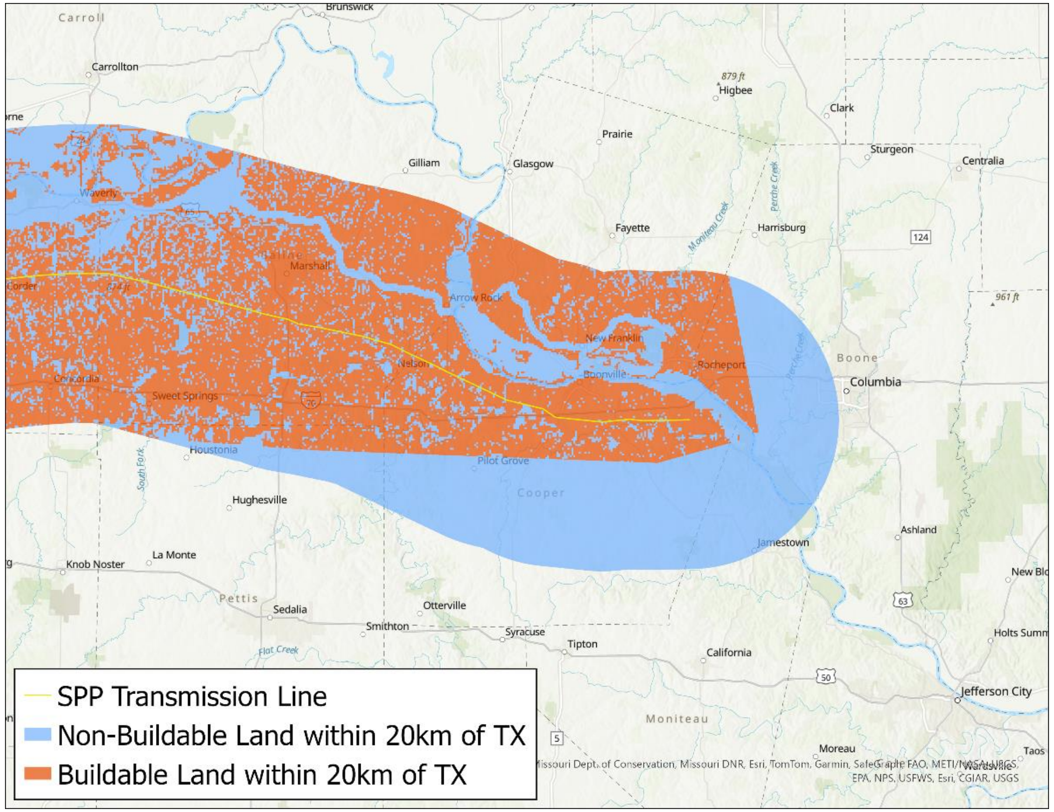
| | | | | TNC Scenario | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Env: 20, Social: 10 | | | Env: 10, Social: 5 | | | Env: 5, Social: 1 | | |
| NREL Scenario | Wind | Solar | Total | Wind | Solar | Total | Wind | Solar | Total |
| **Reference Case** | | | | | | | | | |
| Central East | 156 | 1,064 | 1,220 | 140 | 863 | 1,003 | 120 | 729 | 849 |
| Central West | 231 | 883 | 1,114 | 174 | 708 | 882 | 143 | 480 | 624 |
| North | 935 | 5,495 | 6,430 | 802 | 4,186 | 4,988 | 661 | 1,094 | 1,755 |
| North Central | 335 | 2,085 | 2,419 | 301 | 1,612 | 1,913 | 238 | 434 | 672 |
| South East | 385 | 3,466 | 3,851 | 321 | 2,945 | 3,266 | 261 | 1,892 | 2,153 |
| South West | 305 | 2,310 | 2,615 | 251 | 1,775 | 2,026 | 226 | 736 | 961 |
| **Total Reference Case** | **2,347** | **15,303** | **17,650** | **1,989** | **12,089** | **14,078** | **1,649** | **5,365** | **7,014** |
| **Limited Case** | | | | | | | | | |
| Central East | 36 | 528 | 565 | 32 | 430 | 462 | 27 | 374 | 401 |
| Central West | 107 | 320 | 426 | 94 | 268 | 362 | 75 | 188 | 264 |
| North | 676 | 1,999 | 2,675 | 576 | 1,562 | 2,138 | 468 | 457 | 925 |
| North Central | 234 | 710 | 945 | 211 | 553 | 764 | 167 | 194 | 361 |
| South East | 109 | 1,504 | 1,613 | 93 | 1,256 | 1,349 | 75 | 873 | 947 |
| South West | 197 | 850 | 1,047 | 172 | 652 | 824 | 160 | 285 | 445 |
| **Total Limited Case** | **1,359** | **5,912** | **7,271** | **1,178** | **4,721** | **5,898** | **972** | **2,372** | **3,343** |

We use the NREL Reference Case and TNC thresholds of 10 and 5 as our base case.

# Land Use Analysis – Transmission Considerations for CPP

1. We take the output of our preceding steps as the input to this transmission network proximity analysis to serve as an illustration how land-use could further be explored with available public data sets.
2. We use transmission of 230⁺ kV or above as a rough proxy for attractive interconnection points.
3. This illustrative analysis assumes that land within 20 kilometers of existing 230⁺kV transmission infrastructure provides the most attractive interconnection options.
4. With the estimated generation potential from the previous step, we remove generation potential that is not within 20 kilometers of the identified transmission lines

This exercise is illustrative and should be modified to produce the nodal data necessary for SPP transmission planning and CPP efforts.




*All shaded areas are within 20 kilometers of transmission lines 230⁺kV or higher, with red denoting areas considered buildable by TNC and blue denoting other areas. Building area depicted above is representative of an environmental threshold of 10 and social threshold of 5.*

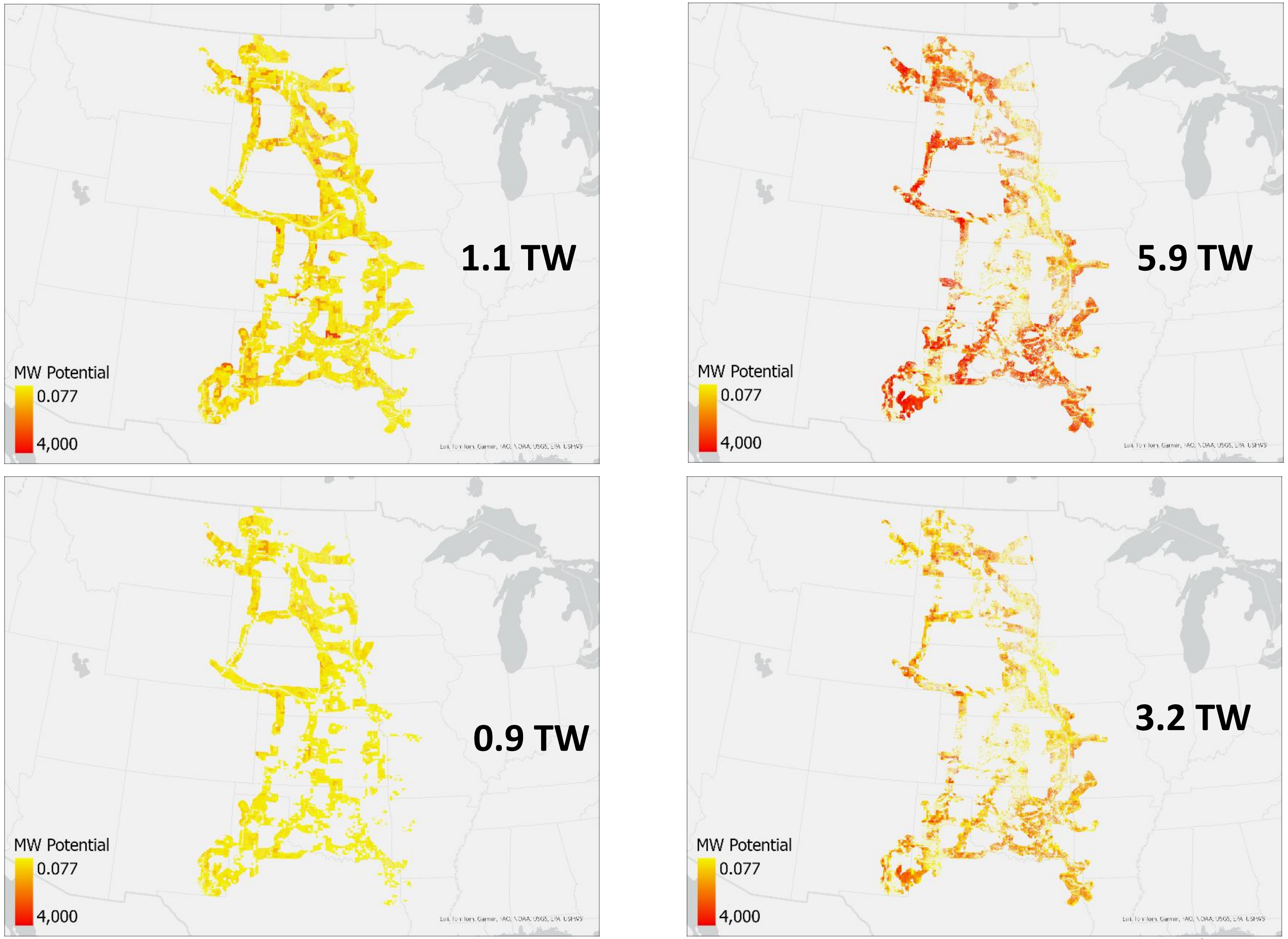
# Generation Potential within 20km of 230$^{+}$kV Transmission

- The maps to the right show generation potential after removing sites farther than 20 km from existing transmission and are more restrictive versions of the previous maps.
- Again, we show two NREL scenarios with the same TNC determined non-buildable areas removed.
- Across SPP, generation potential is estimated to range between 0.9 GW and 1.1 TW for wind and between 3.2 TW and 5.9 TW for solar.
- Even when considering only low-impact land near transmission infrastructure, ample amounts of generation potential exist.

Maps show generation potential for environmental threshold of <10 and social threshold <5.

**Wind** | **Solar PV**

**NREL Reference Access** | **NREL Limited Access**



# Results by FERNS Zone—With Transmission Consideration

- After adjusting for low-impact land within 20 kM of 230+kV transmission, there is still at least 400 GW of solar and wind potential in each zone (6.8 TW for all of SPP).
- All FERNS capacity buildout scenarios are well within these calculated low-impact potential estimates.

## Total GW of Generation Capacity by Zone and Proximity to Transmission

| | Proximity to Transmission | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 10 KM | | | 20 KM | | | 30 KM | | |
| SPP FERNS Zones | Wind | Solar | Total | Wind | Solar | Total | Wind | Solar | Total |
| Central East | 52 | 301 | 354 | 82 | 483 | 566 | 101 | 613 | 714 |
| Central West | 45 | 180 | 225 | 81 | 327 | 408 | 109 | 431 | 540 |
| North | 193 | 1,144 | 1,337 | 317 | 1,832 | 2,149 | 402 | 2,258 | 2,660 |
| North Central | 73 | 308 | 381 | 121 | 509 | 631 | 158 | 687 | 845 |
| South East | 109 | 1,000 | 1,109 | 182 | 1,650 | 1,832 | 229 | 2,051 | 2,281 |
| South West | 96 | 681 | 777 | 150 | 1,085 | 1,235 | 185 | 1,330 | 1,515 |
| **Total SPP** | **569** | **3,615** | **4,184** | **933** | **5,887** | **6,820** | **1,185** | **7,370** | **8,555** |

*For this table we use the NREL reference case for raw generation potential and TNC data filtered to below environmental values of <10 and social values of <5.*

# Clarity in the face of complexity

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