U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.

- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.

- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.

- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

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6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

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8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

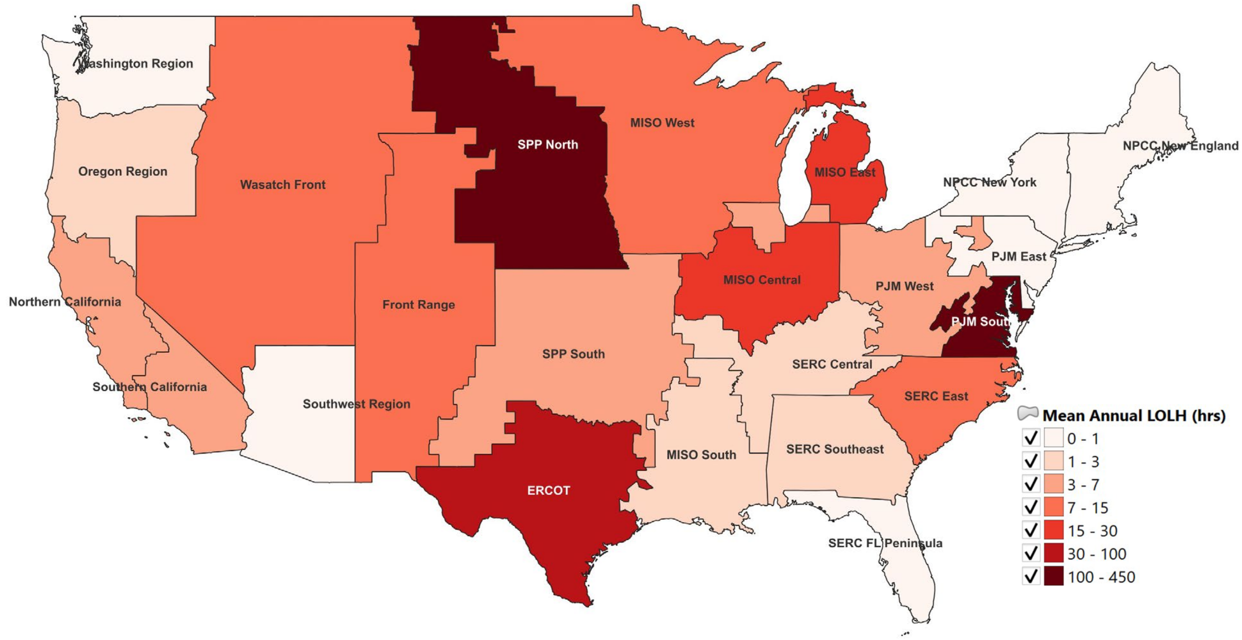


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

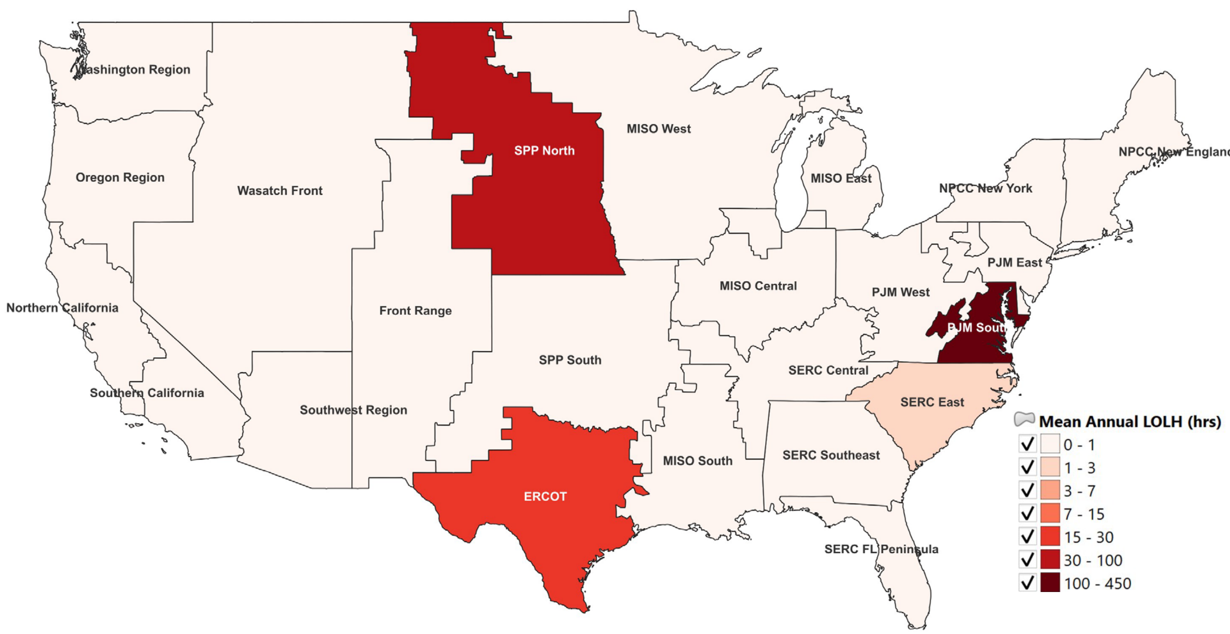


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

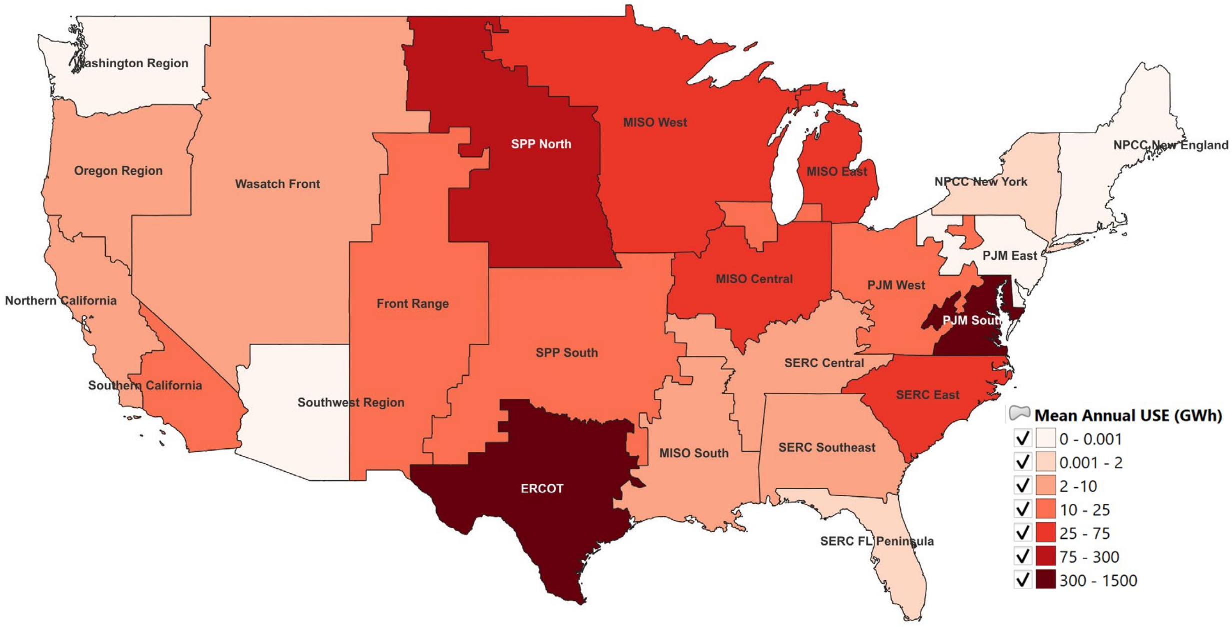


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.

- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.

- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.

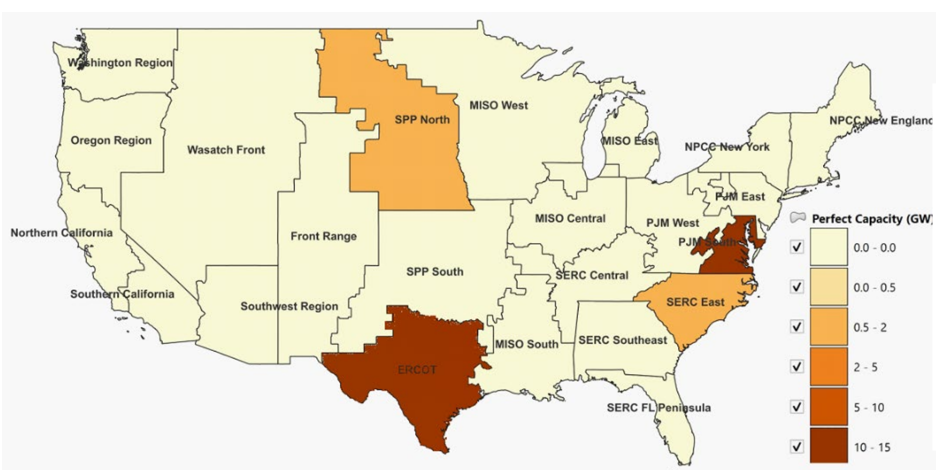
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as "perfect capacity," this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.



	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

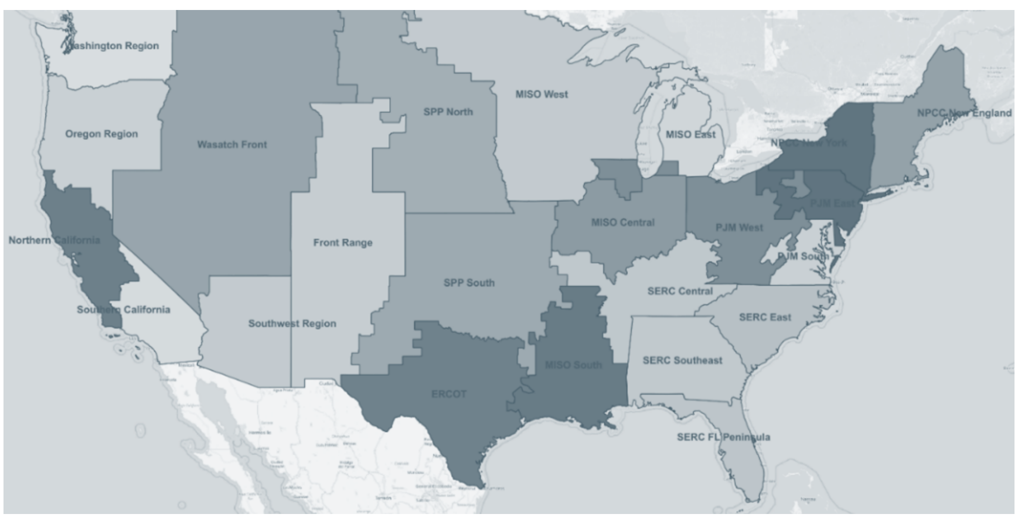


Figure 5. TPRs used in NERC ITCS

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13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

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17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See “Outputs” in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.

- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for “Controllable and Dispatchable Demand Response – Available”, or firm, controllable DR capacity.

- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
  - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
  - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
  - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
  - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
  - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

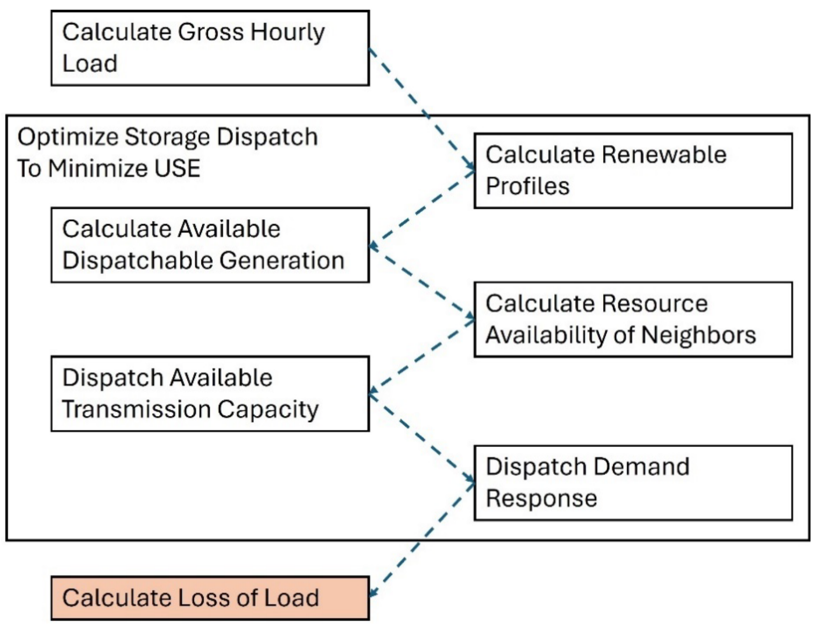


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

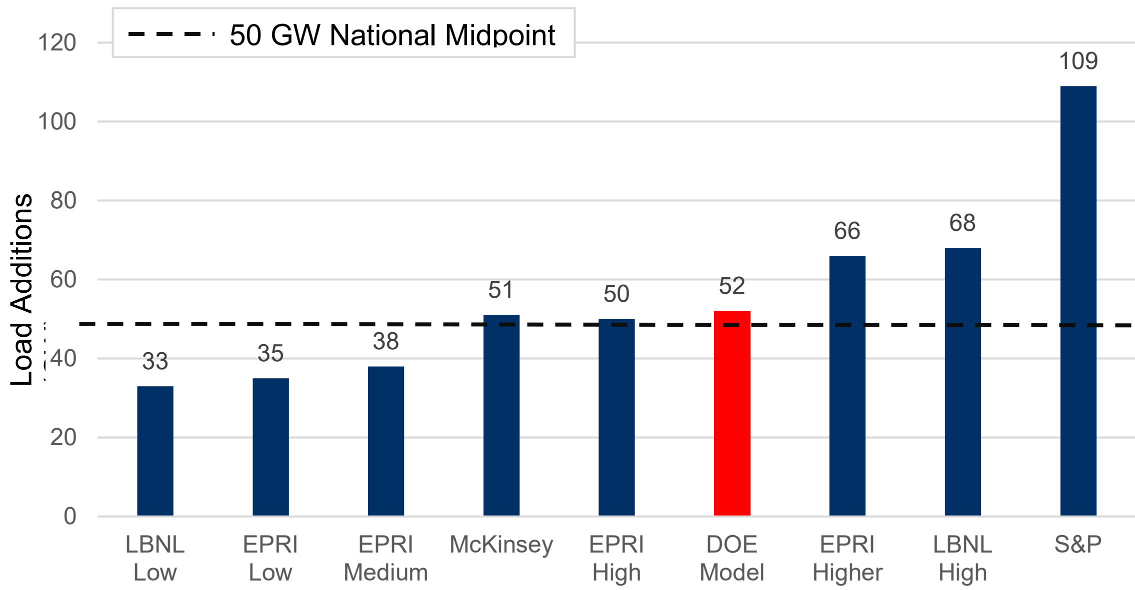


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

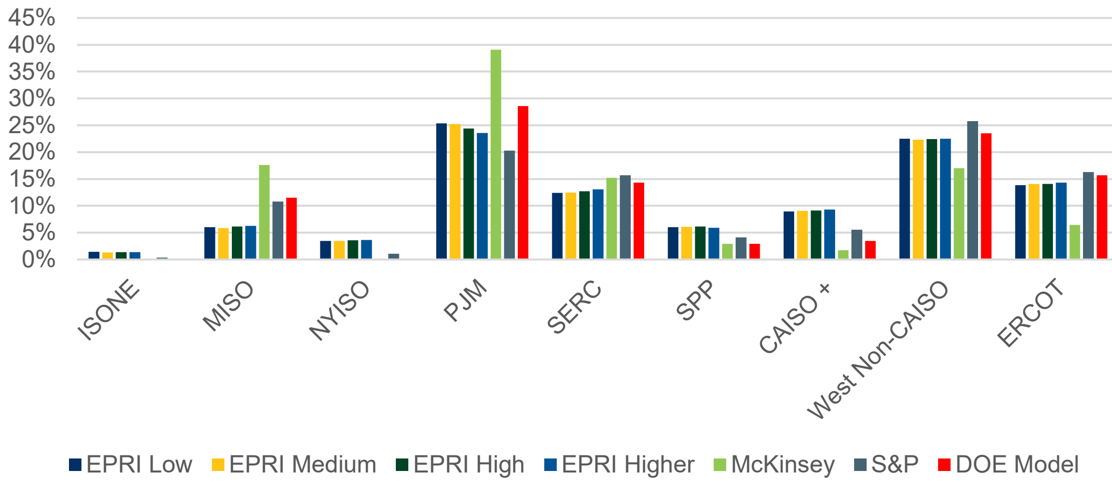


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

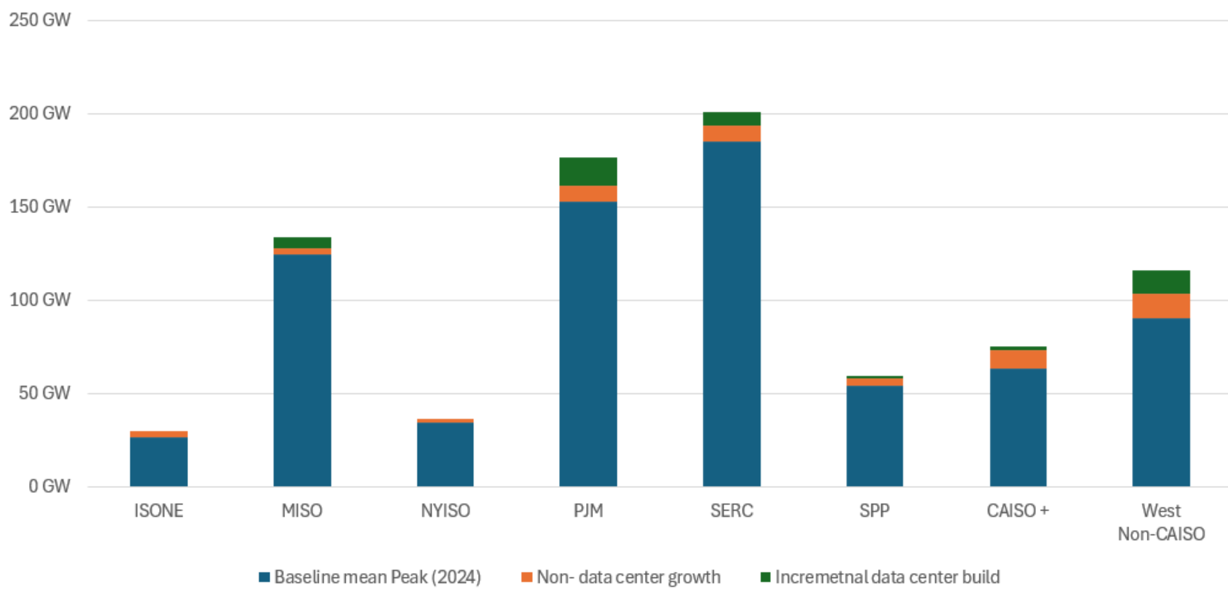


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

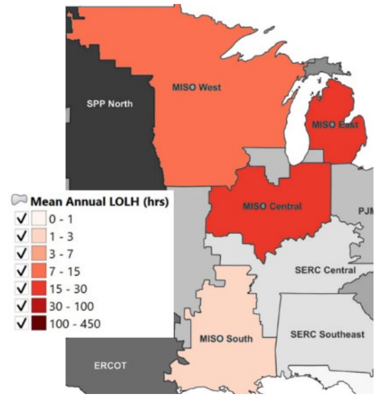


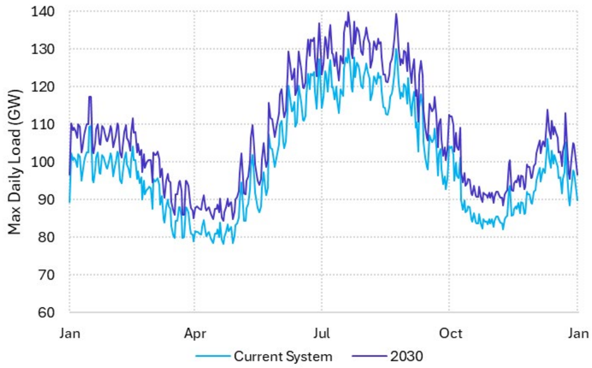
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	130,136	139,846

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	207,319	196,049	228,393

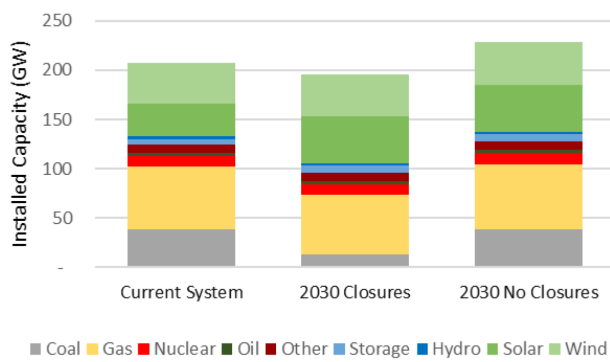


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

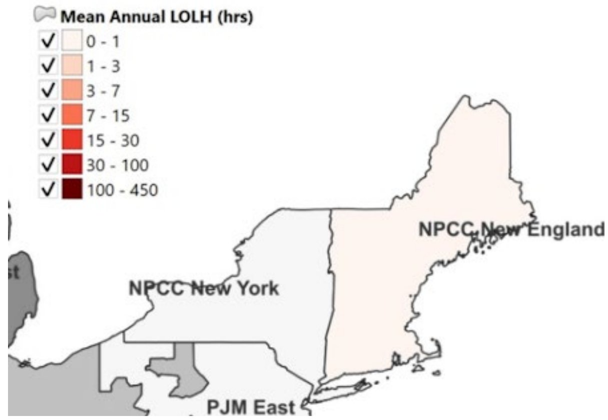
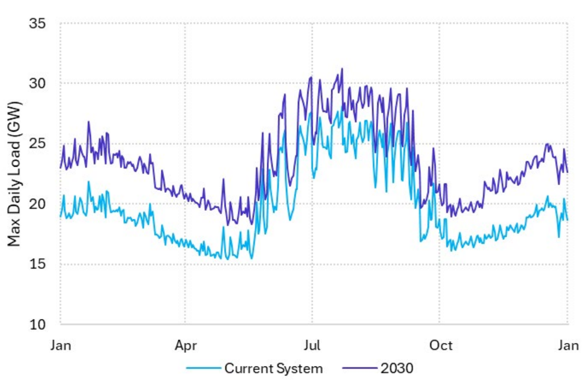


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	28,128	31,261

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

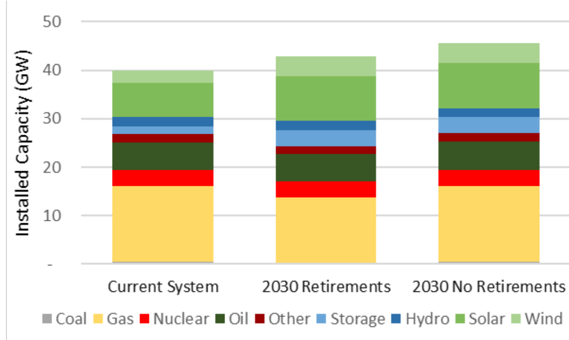


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

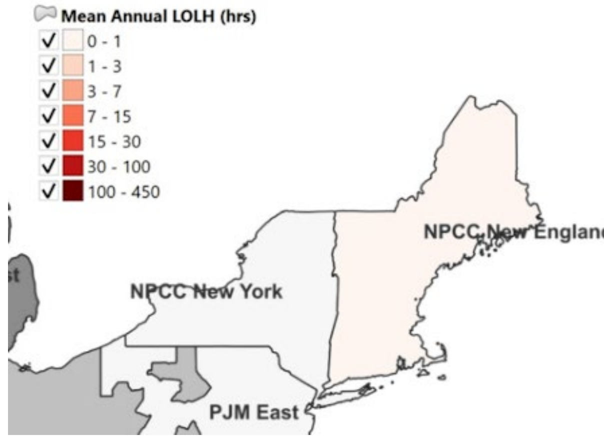
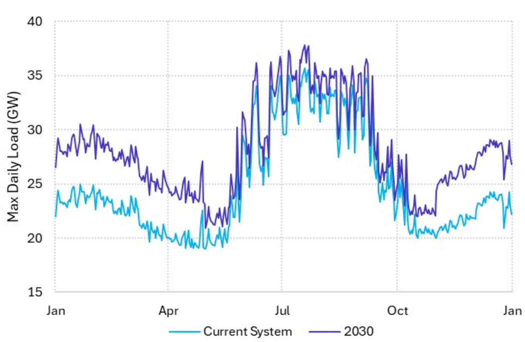


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	35,669	37,844

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

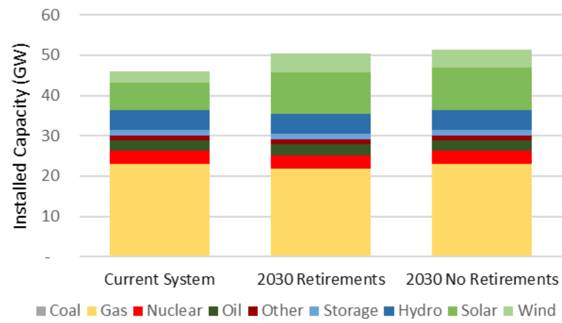


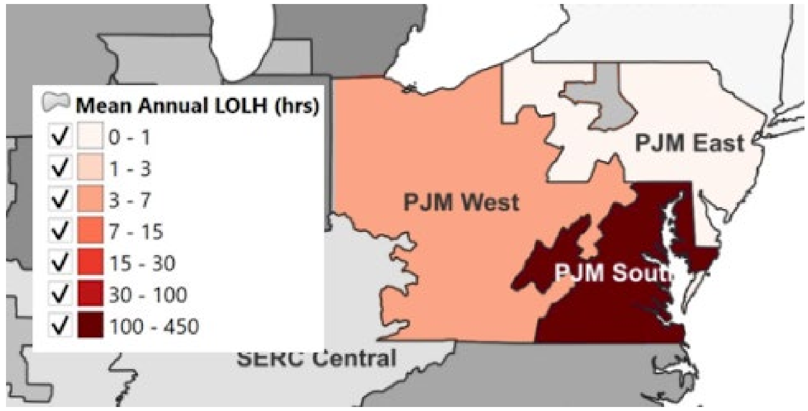
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



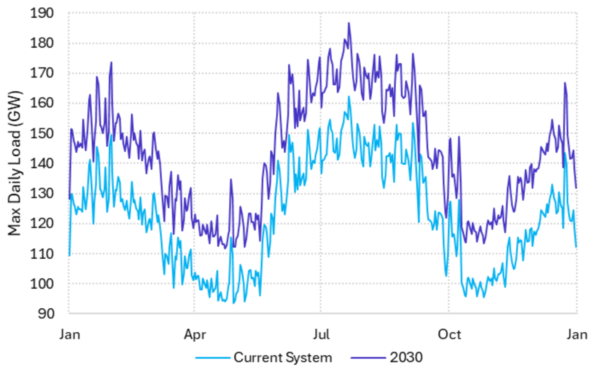
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	Current System	2030 Projection: Plant Closures	2030 Projection: No Plant Closures	2030 Projection: Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

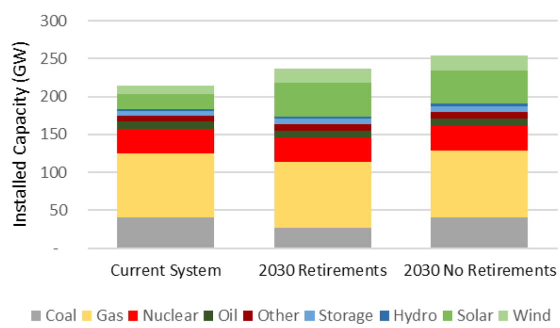


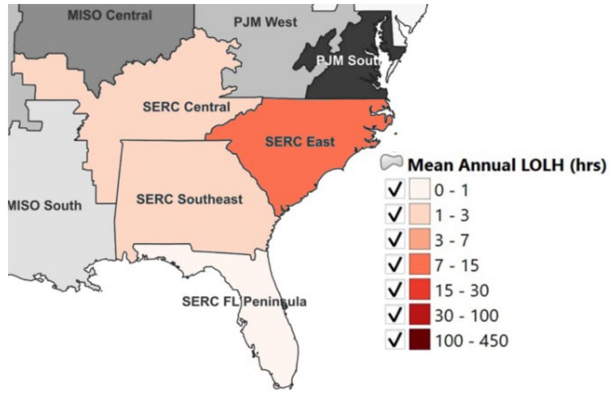
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



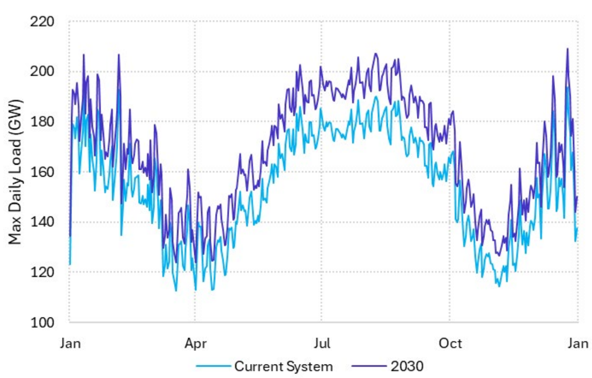
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

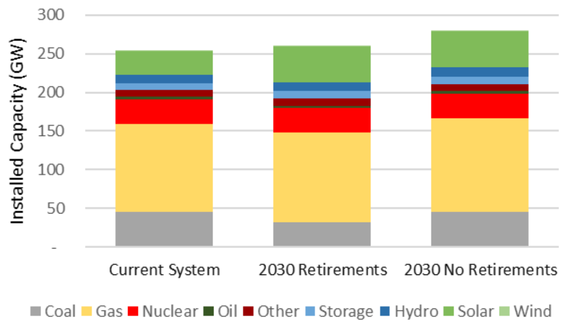


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

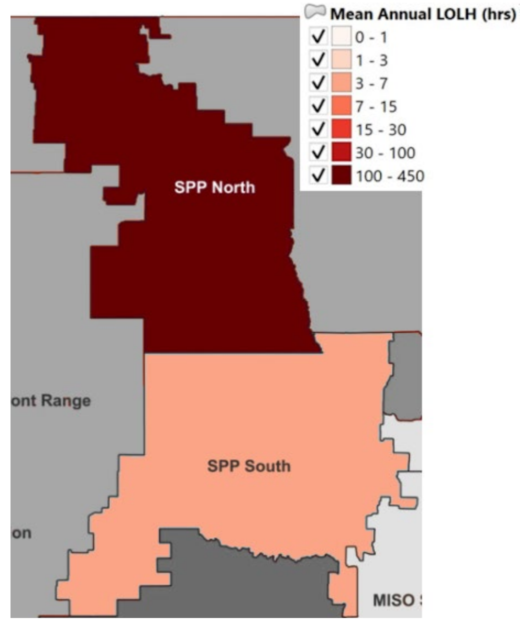
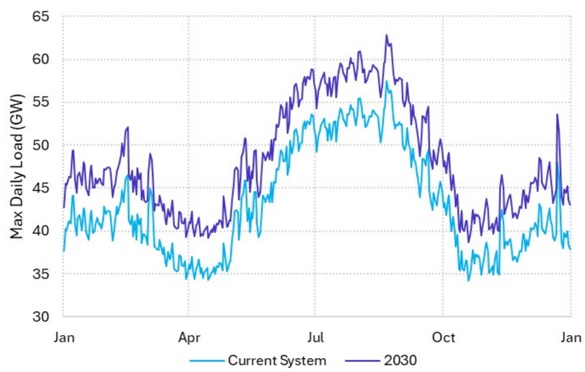


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

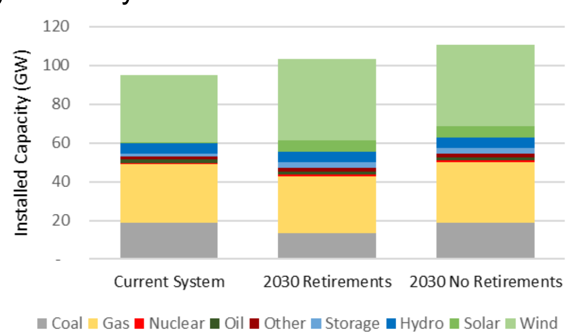


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

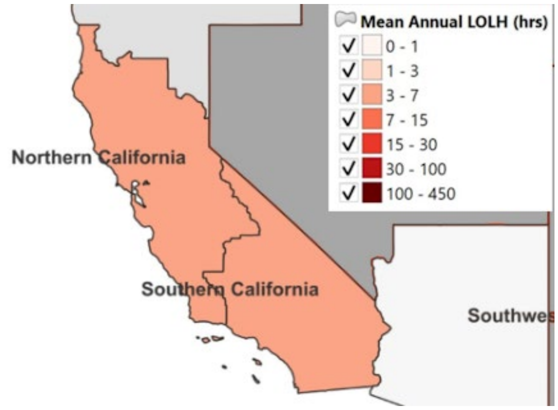
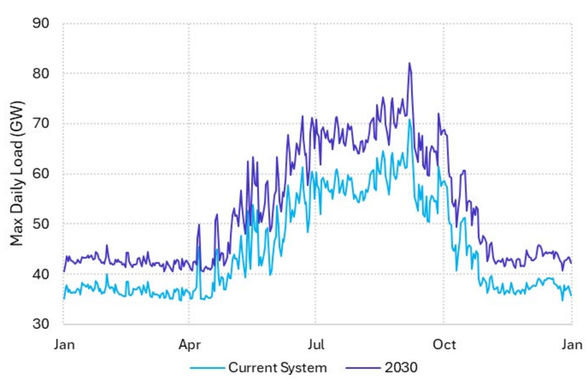


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

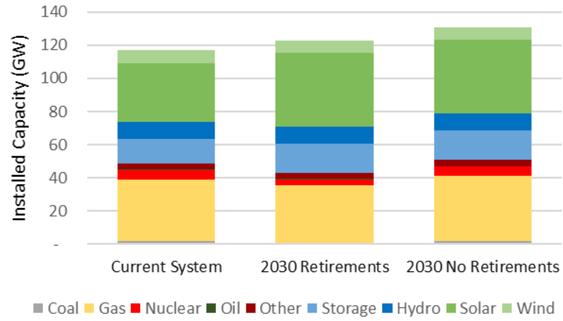


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

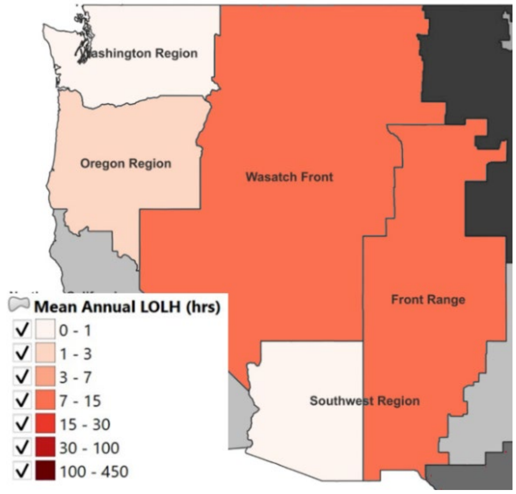
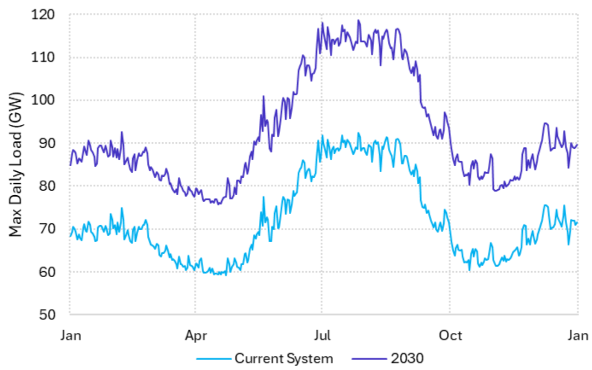


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection: Plant Closures	2030 Projection: No Plant Closures	2030 Projection: Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	92,448	118,657

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	177,929	193,485	206,908

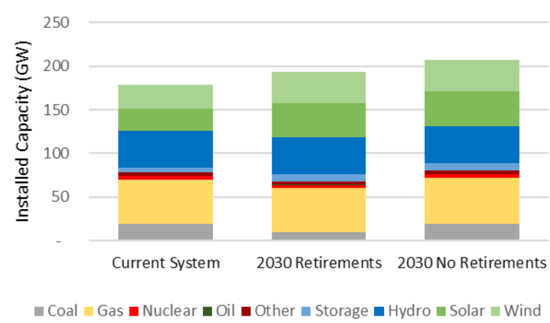


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

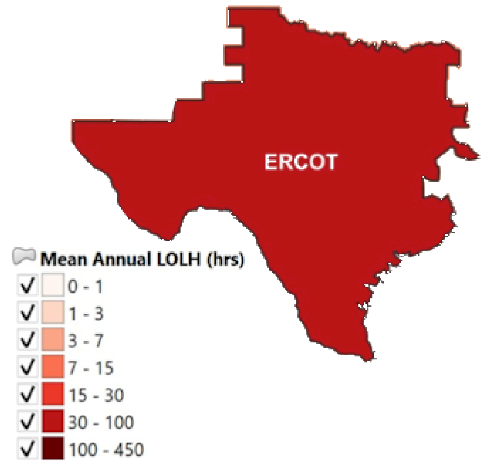
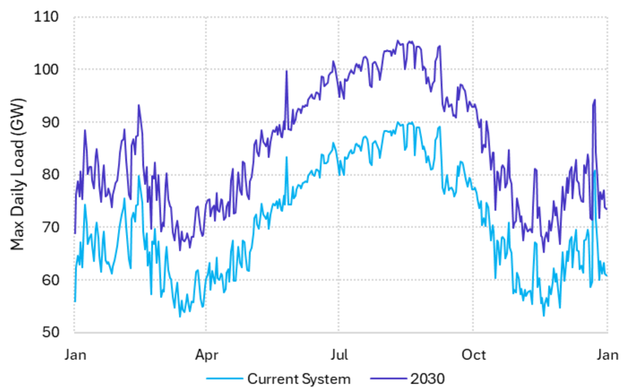


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	Current System	2030 Projection: Plant Closures	2030 Projection: No Plant Closures	2030 Projection: Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

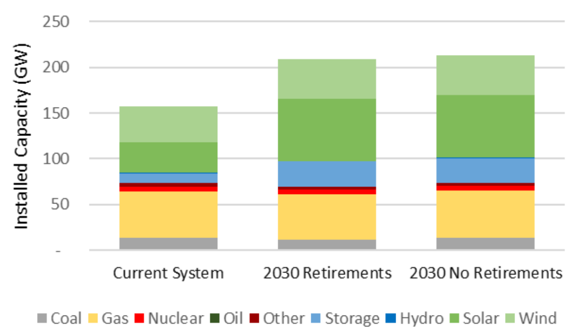


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

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27. NERC, "Interregional Transfer Capability Study (ITCS)." https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, "2024 Long-Term Reliability Assessment," December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

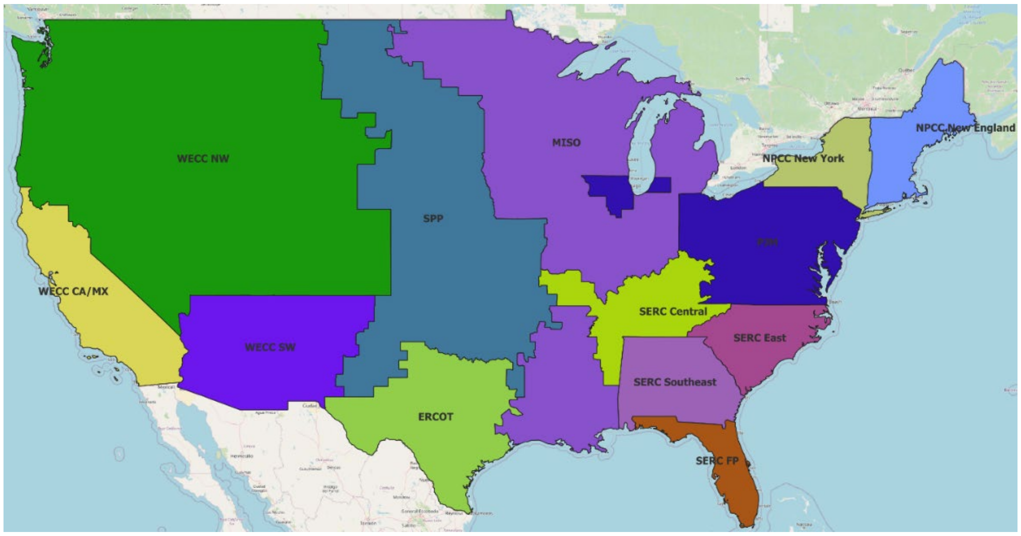

Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \text{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026

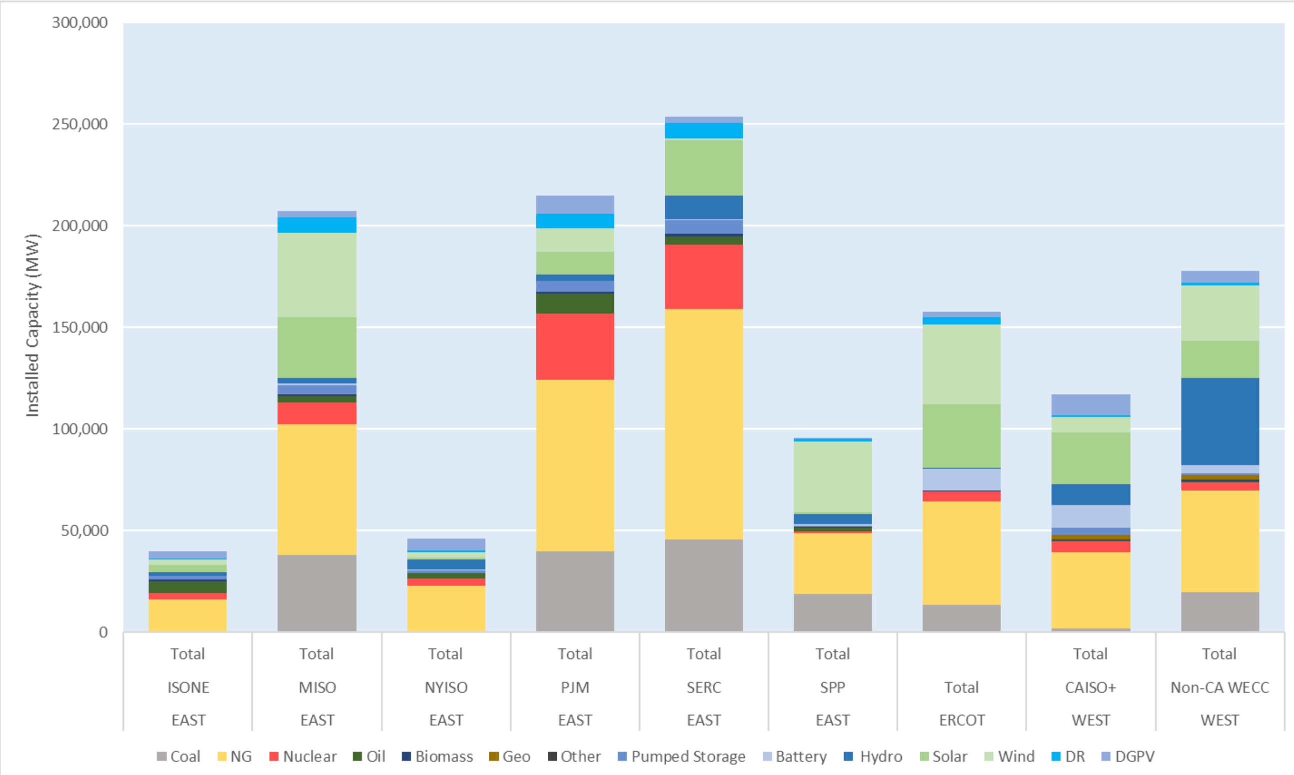

Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

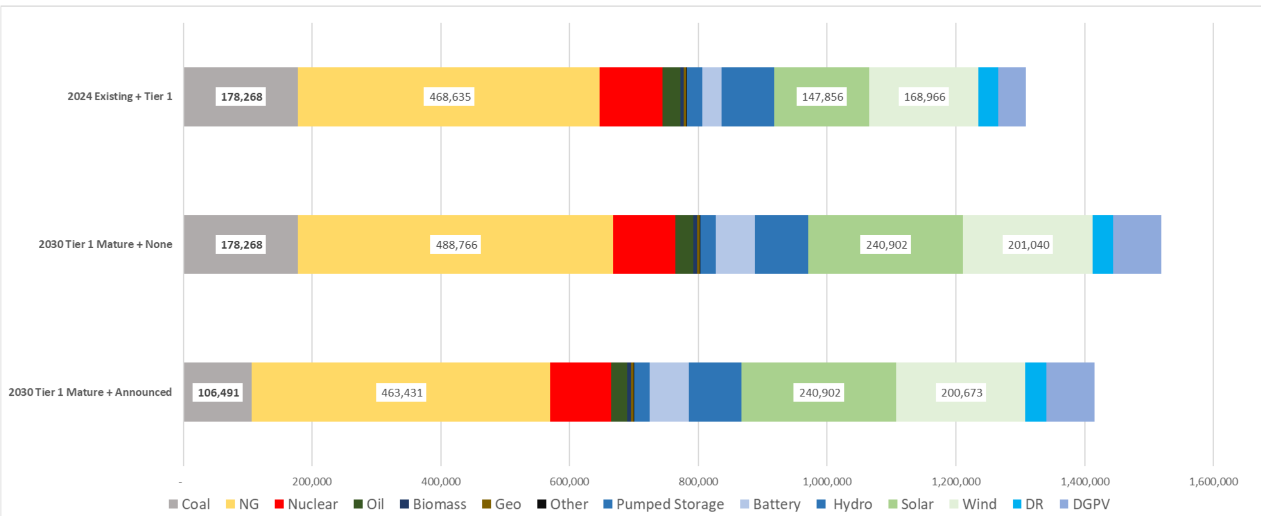

Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

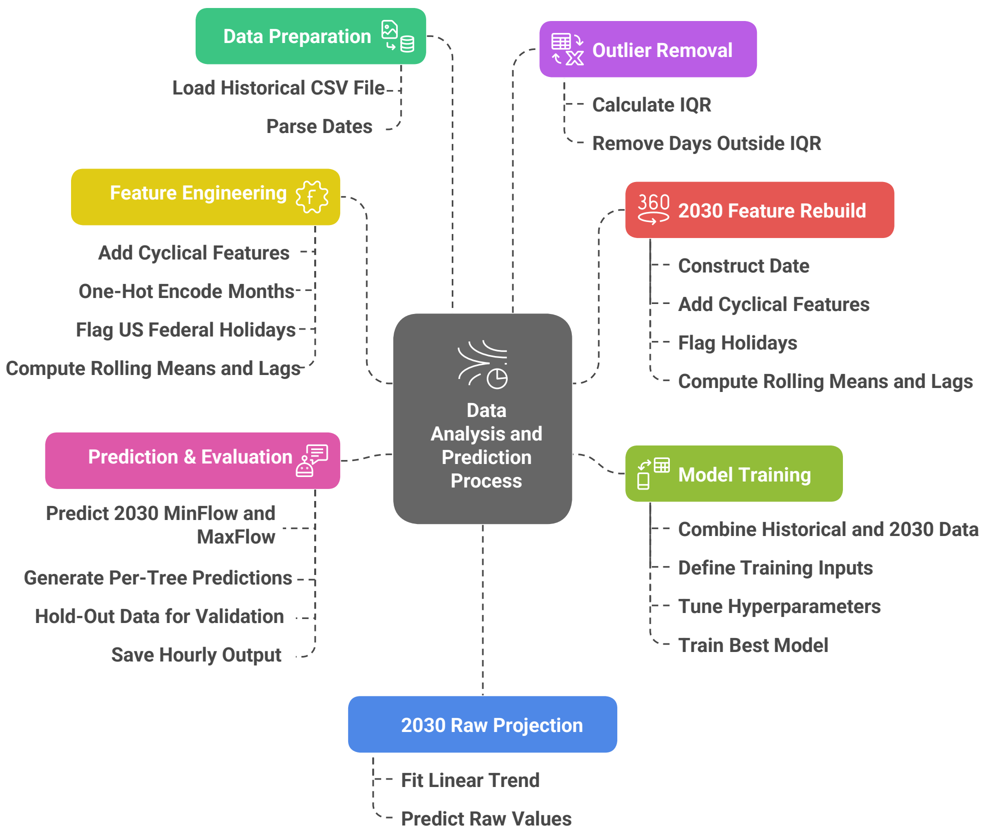

Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

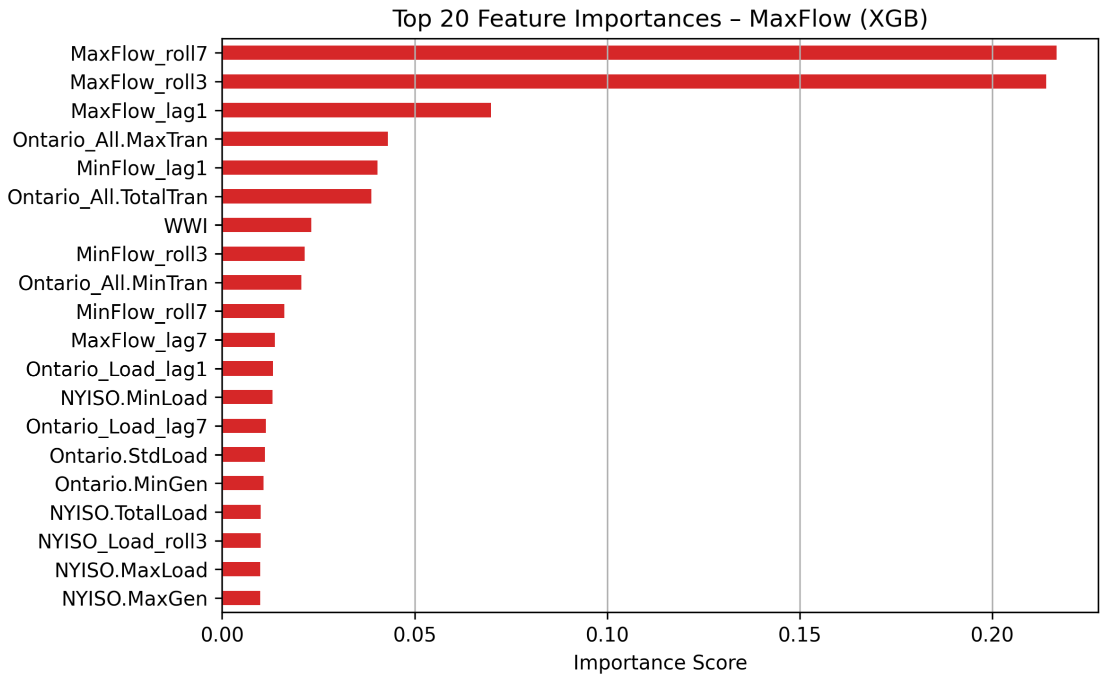

Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

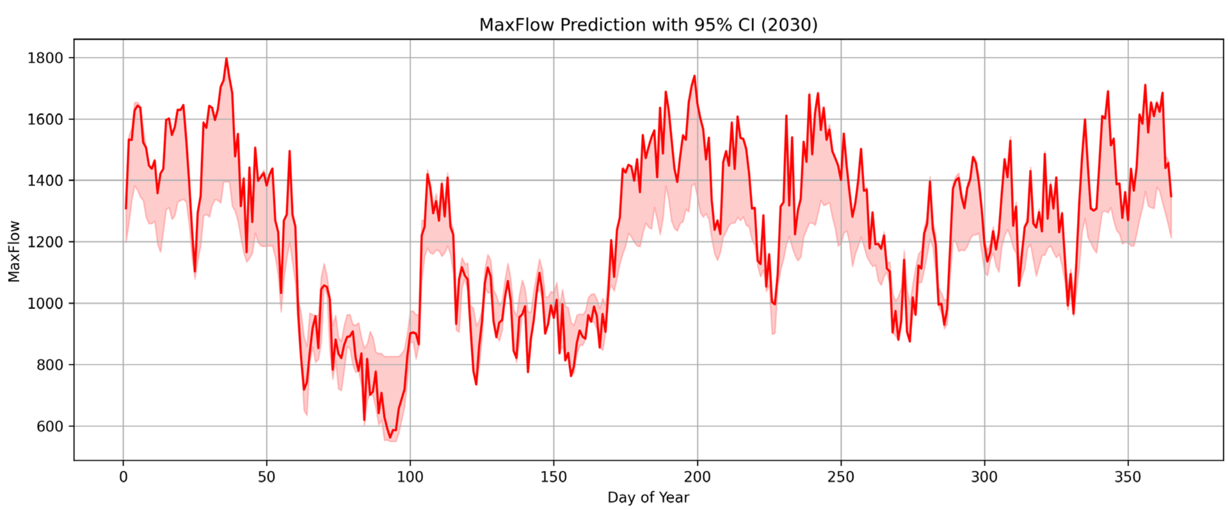

Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

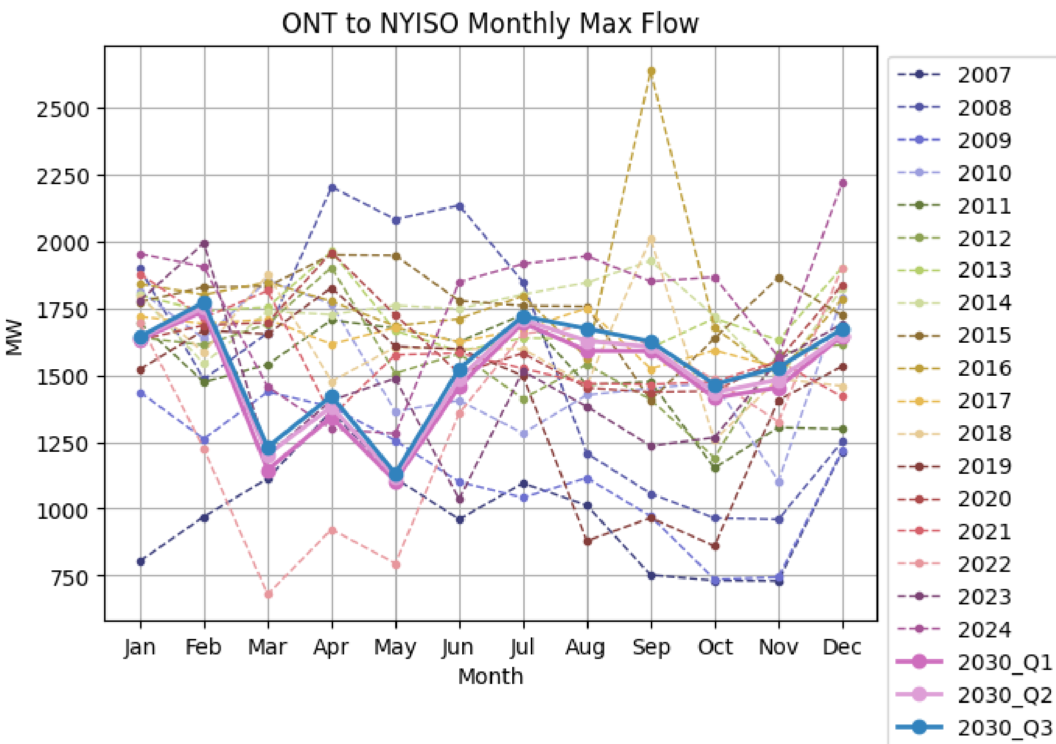

Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load, generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia
(iv) Alberta to Montana
(v) Manitoba to MISO West
(vi) Ontario to MISO West
(vii) Ontario to MISO East
(viii) Ontario to New York
(ix) Hydro-Quebec to New York
(x) Hydro-Quebec to New England
(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

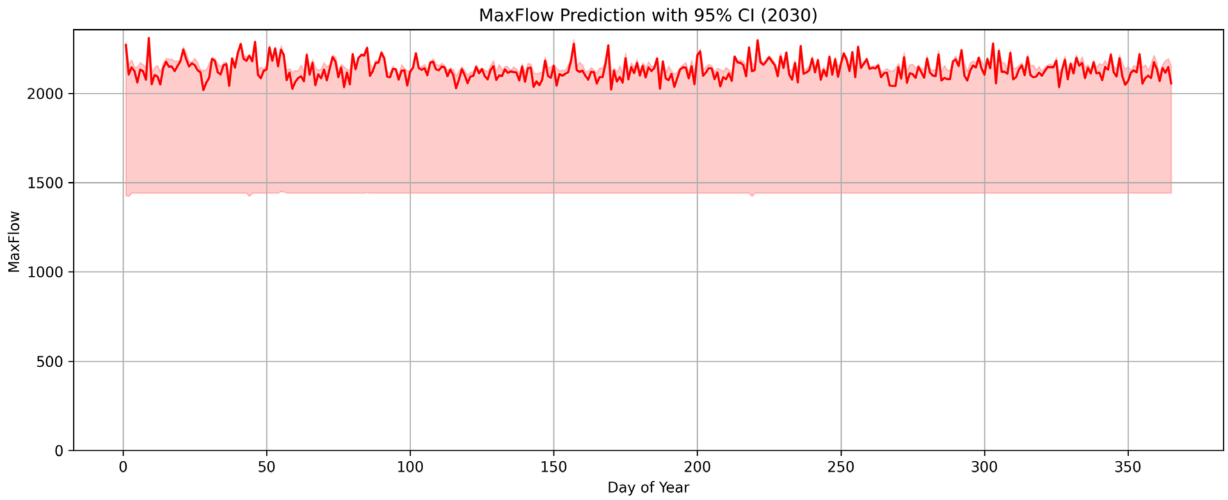

Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

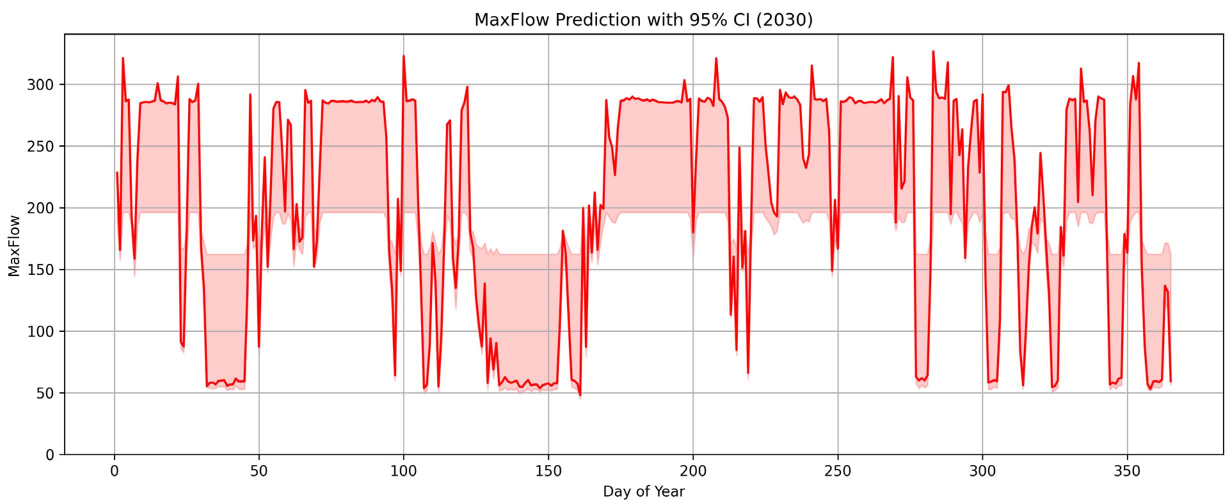

Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

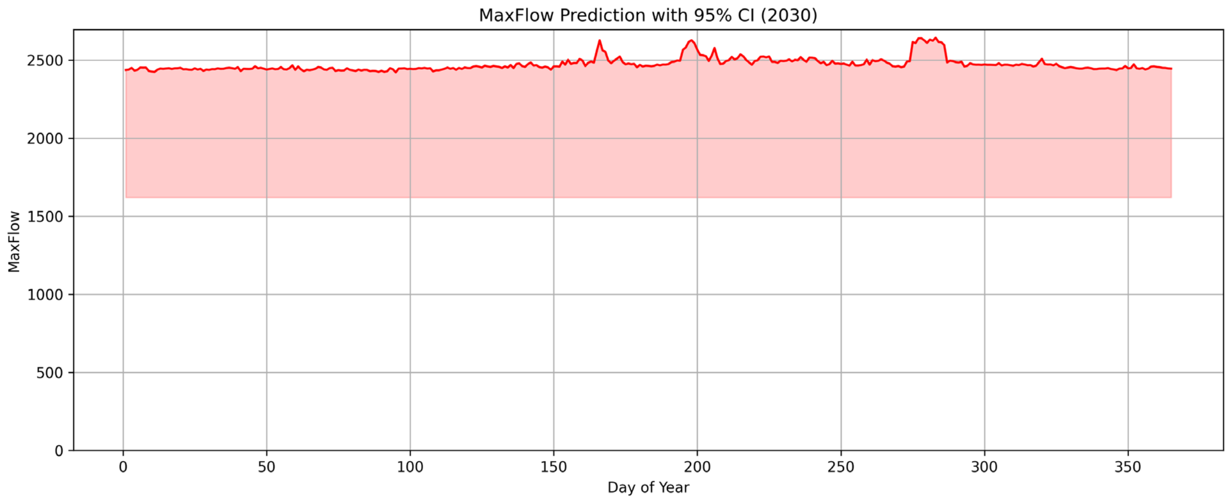

Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

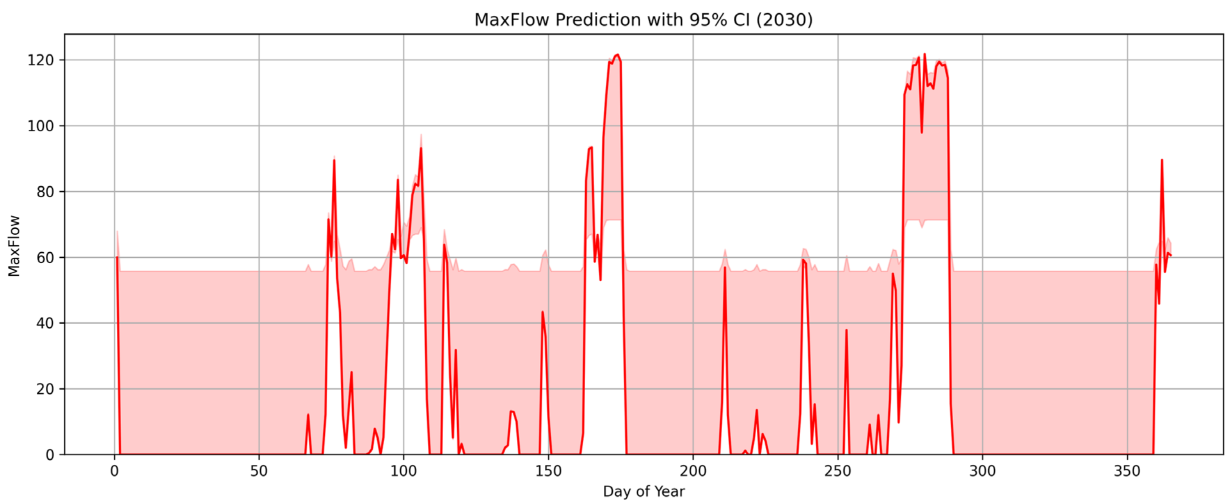

Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

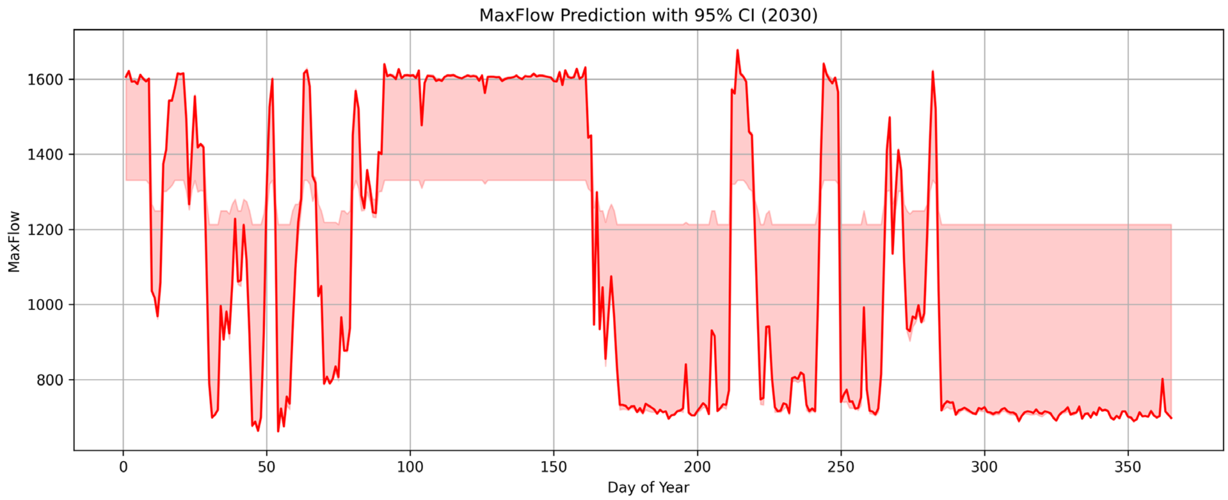

Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

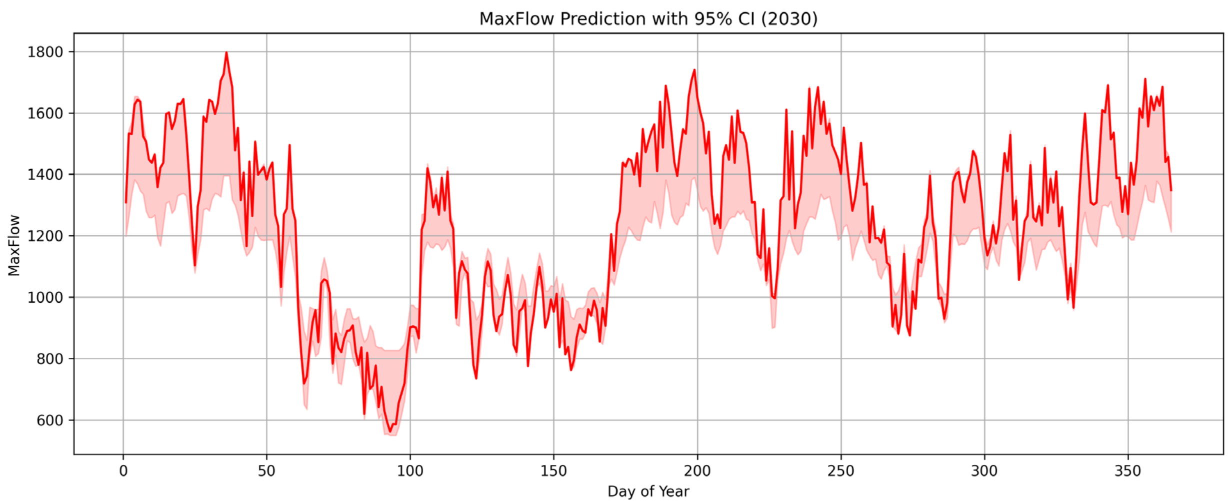

Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

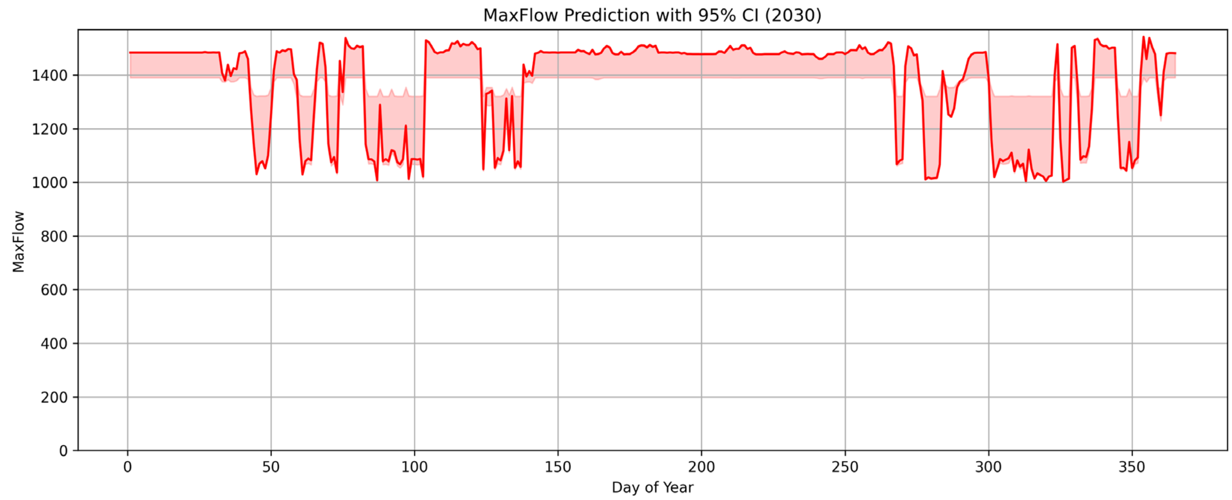

Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

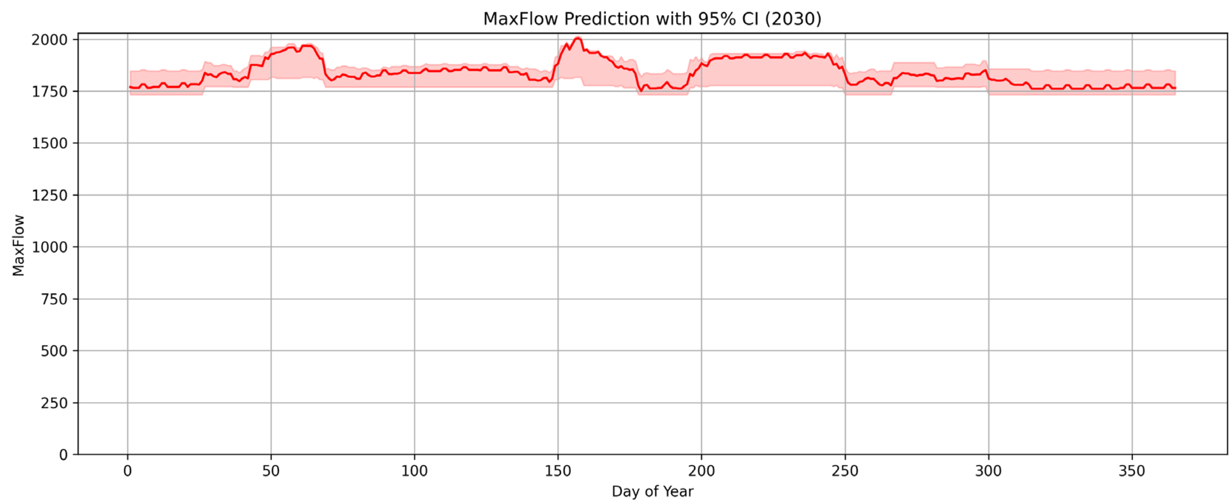

Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

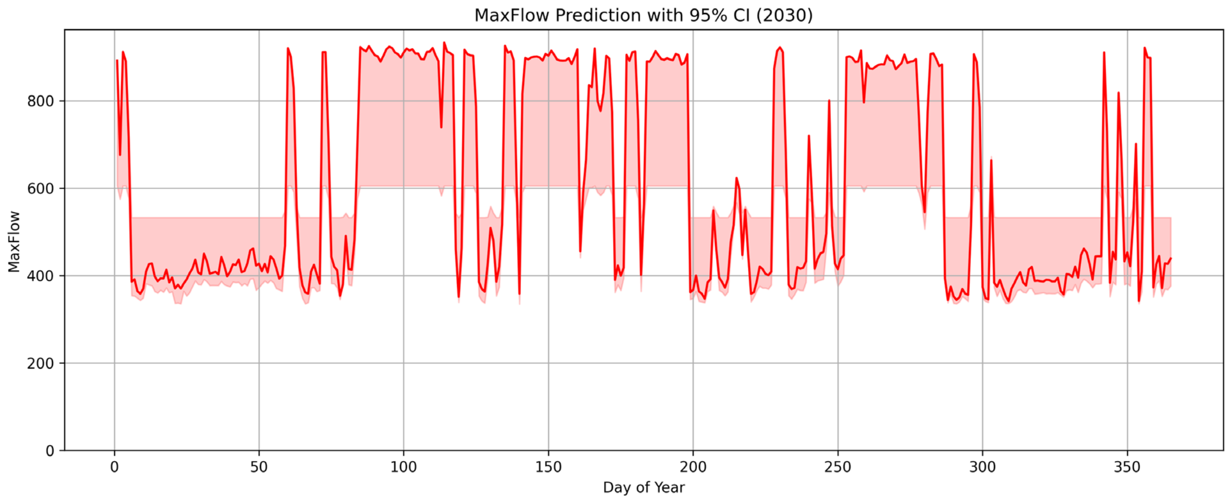

Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy.* It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid

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DOE/Publication Number • July, 7 2025