PNNL-36463

INL/RPT-24-79840

Light Water Reactor Sustainability Program

Value of Nuclear Energy to the Reliability of the North American Power System: Results for Western and Eastern Interconnections

Nader Samaan, Fernando Bereta dos Reis, Kevin Harris, Li He, Konstantinos Oikonomou, Sohom Datta, Abhishek Somani

Pacific Northwest National Laboratory

Timothy R. McJunkin, Binghui Li, and Anudeep Medam

Idaho National Laboratory

July 2024

U.S. Department of Energy

Office of Nuclear Energy

PNNL-36463

INL/RPT-24-79840

Value of Nuclear Energy to the Reliability of the North American Power System: Results for Western and Eastern Interconnections

Nader Samaan, Fernando Bereta dos Reis, Kevin Harris, Li He, Konstantinos Oikonomou, Sohom Datta, Abhishek Somani
Pacific Northwest National Laboratory

Timothy R. McJunkin, Binghui Li, and Anudeep Medam
Idaho National Laboratory

July 2024

Idaho National Laboratory
Light Water Reactor Sustainability
Idaho Falls, Idaho 83415

http://lwrs.inl.gov

Prepared for the
U.S. Department of Energy
Office of Nuclear Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

ABSTRACT

This report documents the fulfillment of a milestone for the United States (U.S.) Department of Energy Office of Nuclear Energy Light Water Reactor Sustainability Program: *Complete a baseline study of regional impact of nuclear power plants and hydrogen production in maintaining grid services and power quality.* Models have been comprehensively demonstrated for the Western Interconnection or Western Electric Coordinating Council area and in the Eastern Interconnection for scenarios representative of past extreme events (e.g., drought and heat waves).

Understanding the impact to the reliability of the bulk electric system of any reduction in generation capacity from nuclear power for any reason is the motivation of this work. Some factors might lead to premature/unplanned closure of nuclear plants, extended outages, or repurposing of nuclear power include:

- Aging infrastructure. Many nuclear power plants in the U.S. are nearing the end of their designed operating lives. Upgrading aging infrastructure can be expensive, and some utilities may choose to retire plants rather than invest in costly upgrades.
- Low wholesale electricity prices. The deregulation of the electricity market in many states has led to increased competition and driven down wholesale electricity prices, causing nuclear power operators to seek other revenue sources for their heat and power like clean hydrogen production.
- Renewables growth. The rapid growth of renewable energy sources like solar and wind power is posing a challenge to traditional generation sources like nuclear. While many see renewables as a key part of the clean energy transition, their intermittent nature requires additional grid solutions for reliable power supply.
- The potential for regulatory decisions to be in conflict. In its 2021 rulemaking, EPA rule (86 FR 880), the Environmental Protection Agency (EPA) set a compliance date for the ban on processing and distribution in commerce of Decabromodiphenyl Ether (DecaBDE). Since DecaBDE is in many components, particularly wiring, of nuclear power plants which are deemed safety related or important to safety three plants would not have been able to restart after their 2023 spring outages and numerous others would have issues in the near future. Fortunately, in this case, EPA provided relief to the nuclear energy industry.

The report provides a summary of the significant role nuclear energy plays in the United States' power generation mix, providing around 20% of the nation's electricity generation, spread across 28 U.S. states. Nuclear power is reliable and mostly unaffected by weather and seasonal changes and provides a consistent source of baseload power. In terms of capacity, nuclear power plants have as much as 26% of balancing area power generation capacity. Nuclear power provides a substantial contribution (e.g., 10% of the inertia in the Eastern Interconnection) of the synchronous spinning mass/inertia that buffers the rate at which frequency will change when a load and generation imbalance occurs (e.g., a large plant trips or a load is suddenly shed due to a transmission outage). This

contribution is critical for maintaining grid stability during sudden changes in load or generation.

A rapid analysis method, that can be setup and provide initial screening result in a matter of several person-days has been developed that provides results for the economic, environmental, and reliability impacts of removing nuclear generation. The method relies on both a supply curve model for economic and environmental assessments, and a Monte Carlo simulation model for reliability analysis. The method has been demonstrated for the Reliability First Electric Reliability Organization/PJM Interconnection, LLC (PJM) and MISO area of the Eastern Interconnection. The result showed over $50/MWh increase in electricity prices, 20kt/h increase in CO_2 emissions in both areas.

A more detailed modeling has also been configured that provides transmission constraints, along with comprehensive production cost modeling. This includes unit commitment and dispatch that considers potential outages using production cost models. The model can be reconfigured based on assumptions about retirements, installation of new energy assets, and load profiles for projected scenarios. It has been comprehensively demonstrated for the Western Interconnection or Western Electric Coordinating Council area and in the Eastern Interconnection for scenarios representative of past extreme events (e.g., drought and heat waves). The results highlight the impact of decreasing the electricity generation of nuclear power for any reason including hydrogen production. It is important to note that with hydrogen production the units will remain tied electrically to the bulk electric system, such that, it continues to provide inertia and would be available to provide electricity in scenarios such as those described in the report to mitigate the strain on the system.

Page intentionally left blank

CONTENTS

FIGURES

TABLES

ACRONYMS

ADS	Anchor Data Set
AS	Ancillary Service
BA	Balancing Authority
BAU	business-as-usual
CA	California
COI	California Oregon Intertie
DCPP	Diablo Canyon Power Plant
DSW	Desert Southwest
EI	Eastern Interconnection
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
GHG	Greenhouse Gas
INL	Idaho National Laboratory
LMP	Locational Marginal Price
LOLH	loss-of-load hours
LOLP	loss-of-load expectation, loss-of-load probability
MC	marginal costs
MMWG	Multiregional Modeling Working Group
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NW	Northwest
NYISO	New York Independent System Operator
PCM	Production Cost Modeling
PDCI	Pacific DC Intertie
PF	Power Flow
PNNL	Pacific Northwest National Laboratory
TELL	The Total Electricity Loads
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

Page intentionally left blank

Value of Nuclear Energy to the Reliability of the North American Power System: Results for Western and Eastern Interconnections

1. INTRODUCTION

This report documents the fulfillment of milestone for the United States (U.S.) Department of Energy Office of Nuclear Energy Light Water Reactor Sustainability Program: *Complete a baseline study of regional impact of nuclear power plants and hydrogen production in maintaining grid services and power quality.*. Models have been comprehensively demonstrated for the Western Interconnection or Western Electric Coordinating Council area and in the Eastern Interconnection for scenarios representative of past extreme events (e.g., drought and heat waves). The results highlight the impact of decreasing the electricity generation for any reason including hydrogen production. It is important to note that with hydrogen production the units will remain tied electrically tied to the bulk electric system such that it continues to provide inertia and would be available to provide electricity in scenarios such as those described in the report to mitigate the strain on the system.

1.1 Background and Motivation

Nuclear offers a reliable, carbon-free source of electricity with the potential to meet growing demands and transition to clean but variable renewable resources, like wind and solar, while addressing environmental and energy security concerns in the U.S. One advantage of nuclear energy is the inertia that it provides. Nuclear plants typically have massive turbines, contributing significantly to the grid's overall inertia. This provides a substantial buffer against frequency dips, making the grid more stable. The role of nuclear power plants in a grid increases substantially when much of the grid is run by renewable sources like solar and wind, which do not provide any inertia.

It is essential to address challenges such as reliability, waste management, and proliferation risks associated with nuclear energy to maximize its benefits. Regular maintenance schedules of nuclear power plants are necessary to provide a stable and reliable source of electricity and operate continuously without interruption. Typical maintenance outages at nuclear power plants involve a series of planned activities aimed at ensuring the safe and reliable operation of the facility. Refueling outages are the most common type, typically occurring every 18–24 months. These outages can last around 32 days on average and for some other maintenance, can even last months. All outages are carefully planned and scheduled to minimize the impact on electricity generation. In the United States, for example, nuclear power plants typically schedule their outages for the spring and fall, when electricity demand is lower. Outages of units are staggered to minimize magnitude of offline power generation. However, some unexpected factors might affect the regular schedules and lead to premature/unplanned closure of nuclear plants, such as:

- Aging infrastructure. Many nuclear power plants in the U.S. are nearing the end of their designed operating lives. Upgrading aging infrastructure can be expensive, and some utilities may choose to retire plants rather than invest in costly upgrades.
- Low wholesale electricity prices. The deregulation of the electricity market in many states has led to increased competition and driven down wholesale electricity prices. This makes it challenging for nuclear plants to cover their operating costs and stay profitable.
- Renewables growth. The rapid growth of renewable energy sources like solar and wind power is posing a challenge to traditional generation sources like nuclear. While many see renewables as a key part of the clean energy transition, their intermittent nature requires additional grid solutions for reliable power supply.

- The potential for regulatory decisions to be in conflict. In its 2021 rulemaking, EPA rule (86 FR 880), the Environmental Protection Agency (EPA) set a compliance date for the ban on processing and distribution in commerce of decaBDE-containing wire and cable products for use in nuclear power generating facilities of January 6, 2023. Many components, particularly wiring, are part of nuclear power plants which are deemed safety related or important to safety. Without relief provided by the EPA through negotiations with the Nuclear Regulatory Commission [1], three plants would not have been able to restart after their 2023 spring outages and numerous others would have issues in the near future [2].

Figure 1 shows the North American Electric Grid Resource Adequacy [3]. We can observe that Midcontinent Independent System Operator (MISO) and Southeastern Electric Reliability Council (SERC) Central are at a high risk. Also, even though PJM is at a low risk, since it is adjacent to MISO and SERC, the loss of nuclear power plants may impact delivery of electricity contracts to MISO and SERC from PJM. MISO region is especially prone to heat domes and wind drought periods with large variable energy resources which necessitates the use of nuclear energy to account for the base load.

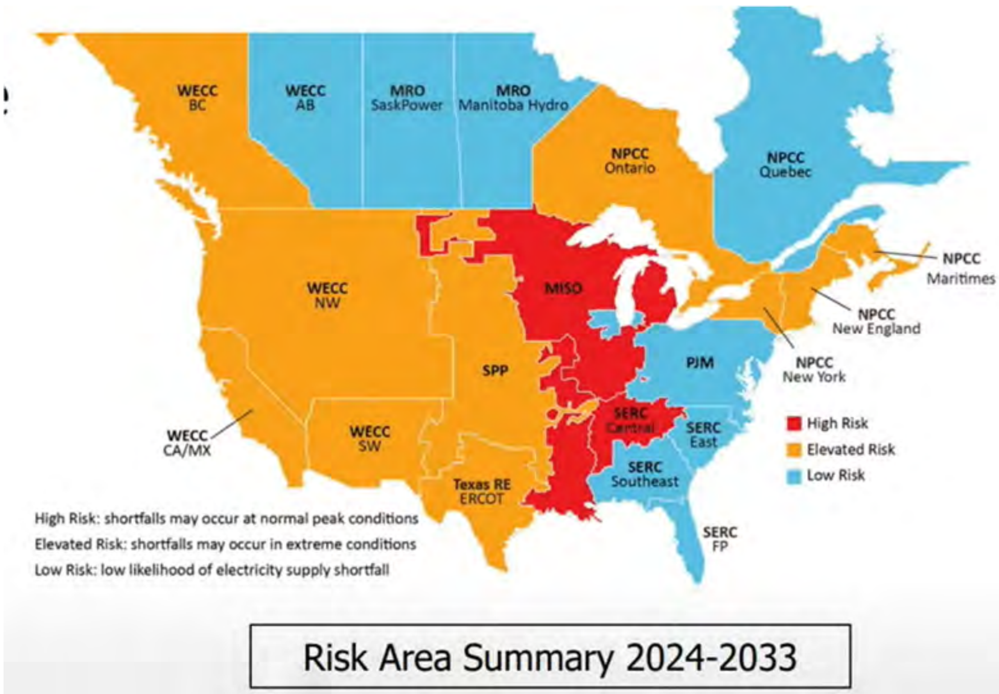


Figure 1. NERC's Long-Term Reliability Assessment 2023. Altered from NERC's 2023 document [3].

1.2 Organization of Report

This report is divided into five main sections. Section 2.0 presents the current nuclear power status in the USA, while Section 3.0 describes a method for rapidly evaluating the financial, environmental, and reliability impacts of removing portions of nuclear power from a region of the grid. In Section 4.0, different scenarios are elaborately presented that considers different threats to the system, including nuclear maintenance, heat wave, and drought. In Section 5.0, the key takeaways from the activity are summarized.

2. NUCLEAR POWER IN USA

Nuclear energy plays a significant role in the United States' power generation mix, providing around 20% of the electricity energy generated. The generation is spread across 28 states and 15 balancing areas. They are reliable and mostly unaffected by weather and seasonal changes and thereby provide a consistent source of baseload power. In terms of capacity, nuclear power plants have as much as 26% of balancing area power generation capacity (Duke Energy of the Carolinas) and as much as 11% interconnection wide (Eastern Interconnection) as seen in Figure 2 [4].

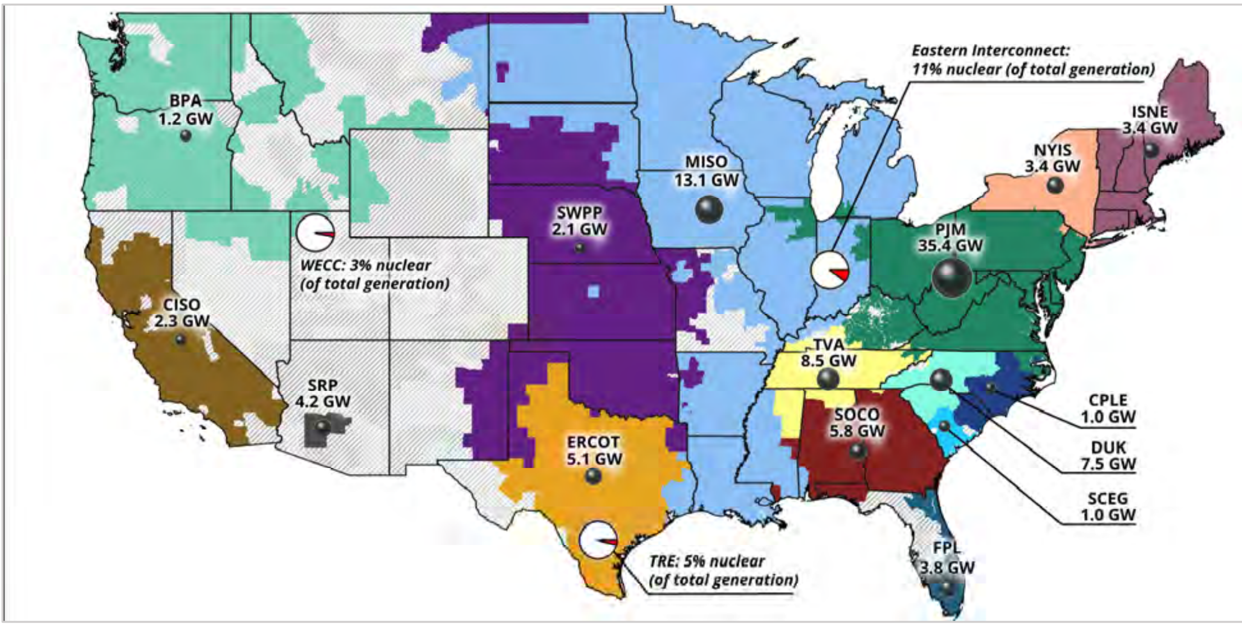


Figure 2. Capacity of nuclear power plants per balancing area and portion of capacity by interconnection in comparison to total power generation capacity.

Figure 2 above shows the nuclear penetration of different regions based on the balancing area. Duke Energy and Tennessee Valley Authority have the highest nuclear share with 26 and 20%, respectively, while PJM Interconnection, LLC (PJM) has the largest nuclear capacity with ~35 GW.

One intrinsic advantage of nuclear energy is the spinning inertia that it provides. Nuclear plants typically have massive turbines, contributing significantly to the grid's overall inertia. This provides a substantial buffer against frequency dips, making the grid more stable. The role of nuclear power plants in a grid increases substantially when much of the grid is run by renewable sources like solar and wind, which do not provide any inertia.

Figure 3 [4] summarizes and Table 1 provides details of the spinning inertia provided by nuclear power plants in each of the balancing areas [5]. The spinning inertia is provided by multiplying the estimated inertia constant with the nameplate capacity of the generating plant. The estimated inertia constant for nuclear plant is determined to be 3.54, as shown in Anderson and Fouad's 2002 book [6].

Table 1. Spinning inertia of balancing authorities that have nuclear power connected, grouped by interconnection.

Balancing Authority	Total Inertia (Mwh*s)	Inertia Nuclear (Mwh*s)	% Nuclear
Eastern Interconnection			
Duke Energy Carolinas (DUK)	110	27	24
Tennessee Valley Authority (TVA)	173	30	17
PJM Interconnection, LLC (PJM)	807	125	16
Duke Energy Progress East (CPLE)	24	4	15
Dominion Energy South Carolina (SCEG)	27	4	14
Florida Power and Light Company (FPL)	127	13	11
ISO New England Inc. (ISNE)	147	12	8
Midcontinent Independent Transmission System Operator, Inc. (MISO)	653	46	7
Southern Company Services, Inc. – Trans (SOCO)	279	21	7
New York Independent System Operator (NYIS)	166	12	7
Southwest Power Pool (SWPP)	260	7	3
Western Interconnection			
Salt River Project (SRP)	64	15	23[a]
California Independent System Operator (CISO)	219	8	4
Bonneville Power Administration (BPA)	127	4	3
Texas Interconnection			
Electric Reliability Council of Texas, Inc. (ERCOT)	361	18	5

[a] In the Western Interconnection it may be more suitable to divide effects of inertia by distributing it into regions of the west; however, for this report we standardize on placing the plant in the balancing authority where EIA indicates the plant connects. The loss of Palo Verde would not leave SRP with the large change in the regional inertia that this chart indicates.

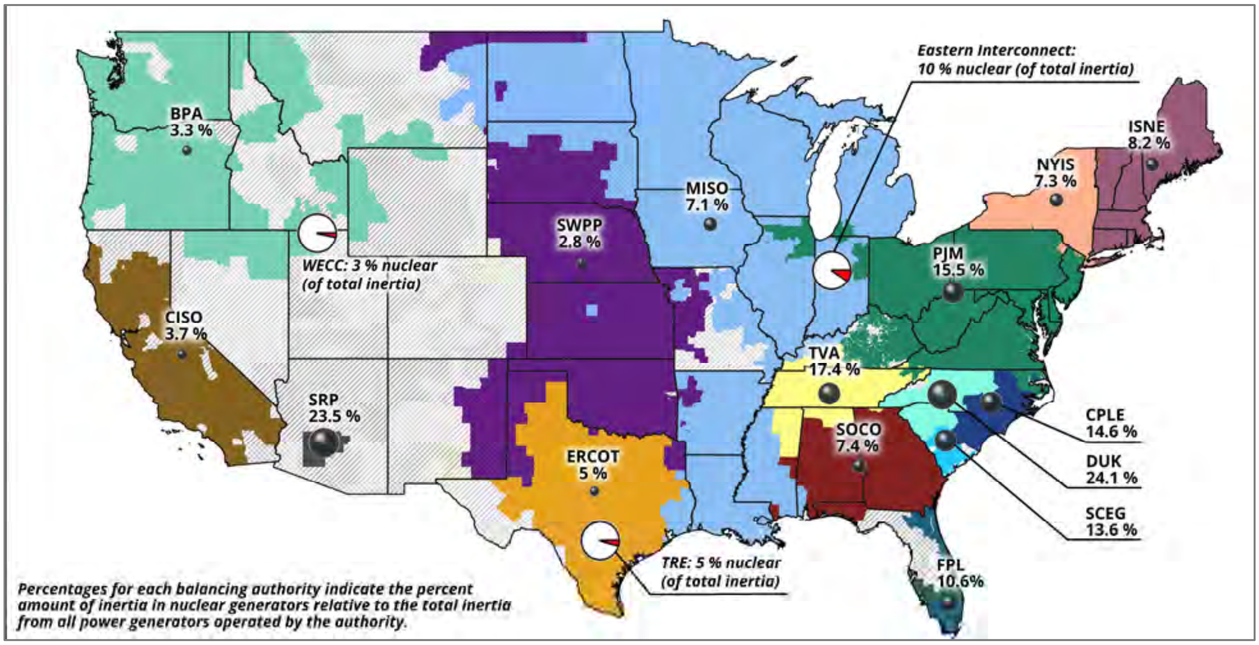


Figure 3. Contribution of synchronous machine spinning inertia on a per balancing authority and interconnection basis.

Table 2 describes the available spinning inertia based on the NERC region and shows that nuclear energy provides roughly 10% spinning inertia in the Eastern Interconnection (EI), 5% in ERCOT, and 3% in the Western Interconnection. If there is a loss of nuclear energy in any of the NERC regions, the amount of natural gas (NG) required to maintain the same amount of inertia will be very high, which would increase the CO_2 emissions.

Table 2. Spinning inertia by NERC region and interconnections.

NERC Region	Total Inertia (GWh*s)	Inertia Provided by Nuclear (GWh*s)	% Inertia Provided by Nuclear
WECC*	853	27	3
Texas RE*	372	18	5
Eastern Interconnection	3180	324	10
Reliability First Corporation	930	124	13
NPCC	323	35	11
SERC	1483	148	10
MRO	419	16	4

* Note that Western Electricity Coordinating Council's (WECC) and Texas are both NERC Regions and Interconnections.

To set the stage for the current state of the electric grid with respect to reliability, this report describes the contribution of nuclear in both capacity and the portion of synchronous spinning inertia supplied to the grid to respectively contribute to resource adequacy and to slow the change in frequency under large disturbances, giving the system time to adapt. Nuclear energy provides a significant portion of both inertia and capacity in the eastern United States such that a large unplanned decrease has a potential to reduce both elements by an amount that could be anticipated to matter. Today, the amount of inertia in the west and east is not considered a concern. However, with greater increase in variable and non-synchronous inverter-based resources, this may not be the case. The information provided about inertia in the report can be used to do analysis of when does a proportional decrease matter. Further, the relative capacity and inertia contributions provide a direction towards what areas to evaluate first, specifically the areas with high amounts of nuclear power and resource adequacy issues in or adjacent to the region of the grid. Specifically, PJM and SERC along with their adjacency to MISO.

3. RAPID ANALYSIS METHOD FOR EARLY RETIREMENT OF NUCLEAR PLANTS

3.1 Introduction

The rapid analysis method consists of three parts (economic analysis, environmental analysis, and reliability analysis) that rely on two different models: a supply curve model for economic and environmental assessments, and a Monte Carlo simulation model for reliability analysis.

The supply curve model calculates hourly marginal cost of electricity generation and hourly carbon emission rate of a balancing area (BA). An overview of the method is given in Figure 4. Specifically, the marginal cost of electricity generation was first calculated for all thermal generating units in a BA by summing up their variable costs and fuel costs. The unit marginal cost indicates the minimum bidding price a unit is willing to accept to generate electricity at its rated capacity. The marginal costs are then sorted in an ascending order to obtain a supply curve of electricity in the BA. The marginal cost of electricity generation in the BA at a given hour is then determined by the intersection of the supply curve with a net demand curve, which is the net load (i.e., gross load subtracts electricity generation from all renewable units). Note that in this analysis, the net demand curve is a vertical line since the inelastic demand is assumed.

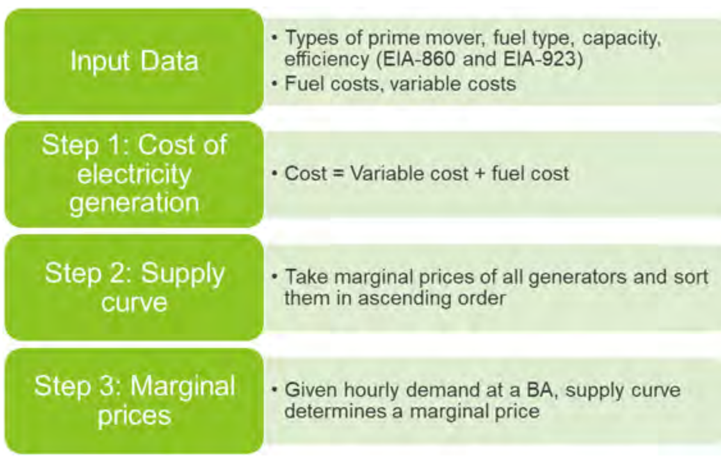


Figure 4. Flow chart of the economic analysis using supply curves.

The Monte Carlo simulation model is for reliability analysis. The model draws equivalent forced outage rates from 2022 NERC Generating Availability Data System and assigns them to each active thermal unit in the generating fleet based on their fuel type (e.g., coal, NG, nuclear). The model then simulates the outage status of each thermal generator at a given hour based on its equivalent forced outage rates and obtains the total available thermal capacity by summing up rated capacities of all available thermal units. For a given hour, the model determines whether a loss-of-load incident occurs by comparing the total available thermal capacity with net load. This simulation is repeated 10,000 times to obtain probabilistic reliability measures, including loss-of-load expectation, loss-of-load probability (LOLP), loss-of-load hours (LOLH), and expected unserved energy (EUE).

3.2 Data Sources

3.2.1 Technologies

This data is drawn from EIA's Form 860, which annually reports all electricity generators in each state by prime mover and energy source. This study maps each generator in EIA Form 860 to a specific technology using its reported prime mover and energy source. Note that although multiple energy sources are provided for some generators, each generator in EIA Form 860 is mapped to a technology only based on the type of prime mover and energy source (i.e., the largest energy source by annual usage).

We categorize all generating technologies into thermal generators (i.e., fossil-fuel fired power plants and nuclear power plants) and non-thermal generators (i.e., renewable energy and energy storage). For economic analysis, we only consider thermal technologies and assume zero marginal costs for renewable units and energy storage. In PJM, there are a total of 35 thermal generating technologies, accounting for 189,421 MW of nameplate capacity. For simplicity, we only consider the nine largest technologies by nameplate capacity, which accounts for 95% (or 180,316 MW) of total thermal generating capacity at PJM. Similarly in MISO, there are a total of 37 thermal generating technologies with a combined nameplate capacity of 154,424 MW, and we only include the seven largest technologies by installed capacity, which accounts for 93% (or 143,669 GW) of total thermal capacity. The modeled technologies at PJM and MISO are listed in Table 3. The capacity mixes in PJM and MISO are shown in Figure 5.

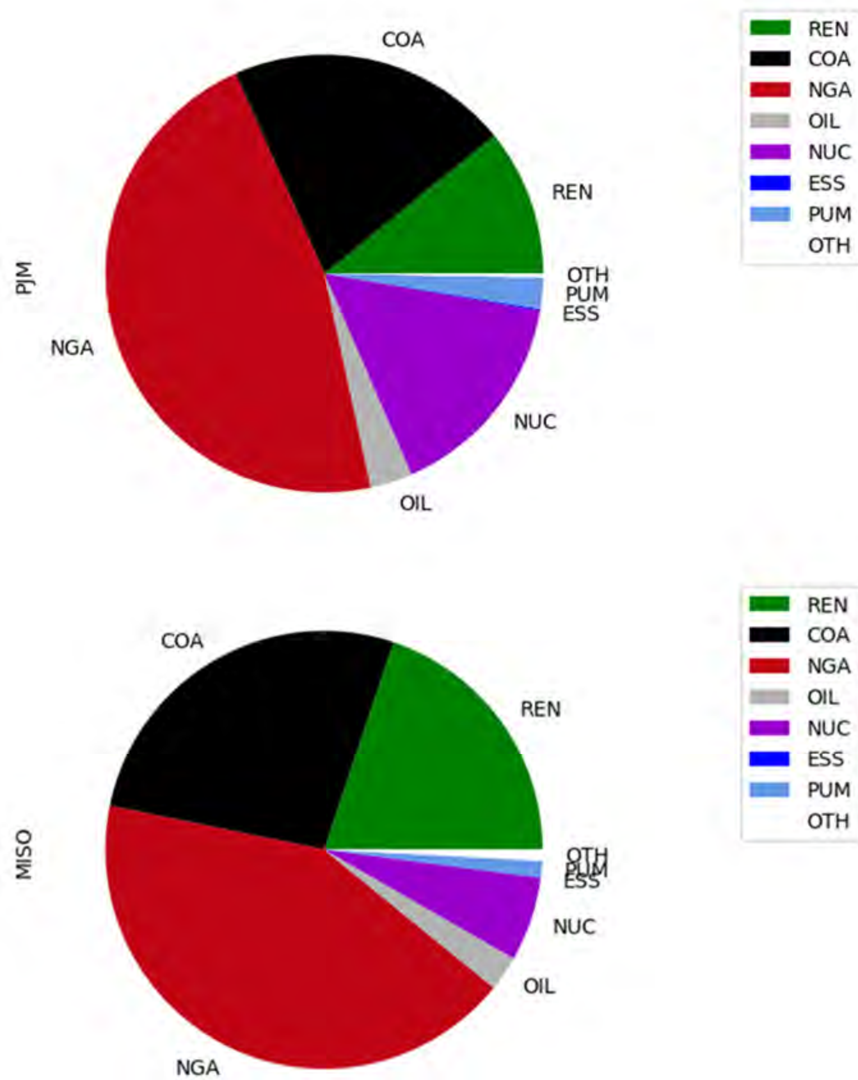


Figure 5. Capacity mixes in PJM (top) and MISO (bottom) by fuel category in 2022 [4]. REN – Renewable, COA – Coal, NGA – Natural gas, OIL – Oil, NUC – Nuclear, ESS – Energy storage, PUM – Pumped hydro, OTH – Others.

Table 3. Considered technologies mapped from EIA Form 860 to this study in PJM and MISO.

Technology	Prime Mover[a]	Energy Source[b]	Nameplate Capacity (MW)	
			PJM	MISO
Steam turbine, bituminous coal	ST	BIT	36,224	13,262
Steam turbine, sub-bituminous coal	ST	SUB	5,705	35,675
NG Combined Cycle	CT	NG	32,357	22,656
NG Combined Cycle	CA	NG	21,036	14,024
NG Single-Shaft Combined Cycle	CS	NG	7,297	15,407

Technology	Prime Mover[a]	Energy Source[b]	Nameplate Capacity (MW)	
			PJM	MISO
NG Combustion Turbine	GT	NG	29,585	28,435
NG Steam Turbine	ST	NG	10,228	0
Petroleum Liquids	GT	DFO	3,418	1,941
Nuclear	ST	NUC	34,467	12,269
Hydro	HY	WAT	3,290	2,457
Pumped hydro	PS	WAT	5,046	2,417
Battery energy storage	BA	MWH	257	73
Flywheel energy storage	FW	MWH	20	0
Solar PV	PV	SUN	7,412	4,549
Onshore wind	WT	WND	10,760	29,844
Offshore wind	WS	WND	12	0
Total			207,113	183,009

Notes:

a. Prime mover code from EIA Form 860: ST – Steam turbine, HY – Hydro turbine, PS – Pumped hydro, GT – Gas turbine, CA – Combined cycle steam part, CT – Combined cycle combustion turbine part, PV – Photovoltaic, CS – Single-shaft combined cycle, WS – Wind offshore, WT – Wind turbine, PV – Photovoltaics, FW – Flywheel, BA – Batteries.

b. Energy source code from EIA Form 860: WAT – Water, BIT – Bituminous coal, LFG – Landfill gas, NG – Natural gas, NUC – Nuclear, DFO – Distillated fuel oil (including diesel, No. 1, No. 2, and No. 4 fuel oils), WND – Wind, SUN – Solar, MWh – Energy storage.

3.2.2 Technical Parameters: Thermal Efficiencies

Thermal efficiencies are essential in the calculation of fuel consumption of a generating unit. The efficiencies of all thermal units are derived from EIA Form 923 [7], Power Plant Operations Report for the year 2022. We calculate the efficiencies at plant level by dividing the annual net electricity generation by the annual heat input of a plant, and then assume that the thermal efficiencies of all generating units are identical in the plant, because a plant might consist of multiple generating units. Note that the method could potentially result in abnormal values of efficiency (e.g., negative or greater than 100%), and we replace these values by the median efficiency of other power plants in the same technology category. In addition, because EIA Form 923 misses heat consumption in nuclear units, we use 32% as the thermal efficiency of all light water reactor nuclear units in this study based on the EPA MARKAL database [8] and the National Renewable Energy Laboratory’s Annual Technology Baseline [9].

3.2.3 Technical Parameters: Emission Factors

Emission factors are primarily obtained from EIA’s Carbon Dioxide Emissions Coefficients [10]. The screening analysis only considers carbon emissions. Detailed emission factors are given in Table 4.

Table 4. CO_2 emission factors by fuel.

Fuel	CO_2 Emission Factor (kg/GJ)
Coal, bituminous	88.4
Coal, sub-bituminous	92.1
Natural gas	50.1
Distillated fuel oil	70.3
Nuclear	0.0

3.2.4 Costs

In engineering economic studies, marginal cost of electricity generation is typically affected by investment costs, fixed costs, variable costs, and fuel costs. In this study, we assume that all investment costs are paid for; therefore, neglecting investment cost terms. Fixed costs represent operations and maintenance costs that are independent of generation level; therefore, these fixed costs do not affect the marginal cost of electricity generation. Variable costs include operational expenses that are dependent on the generation level and are included in the marginal cost calculation. Cost estimates were obtained primarily from the EPA MARKAL database and National Renewable Energy Laboratory's Annual Technology Baseline.

The other component in the unit marginal cost is fuel cost, which includes coal (bituminous and sub-bituminous), NG, distillate fuel oil, and uranium. The fuel prices are drawn from Electric Power Monthly 2022 in terms of per unit thermal value (Figure 6). Note that we assume zero variable costs and fuel costs for renewable units and energy storage units.

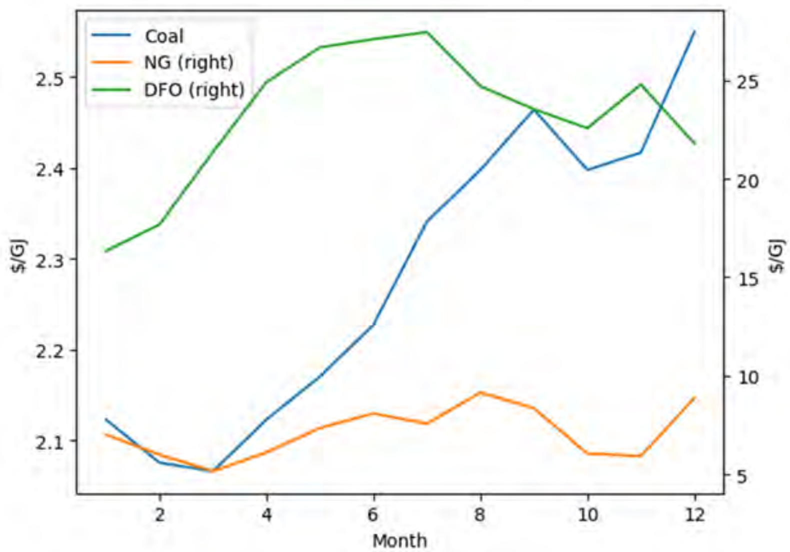


Figure 6. Fuel prices used in this study. NG – natural gas, and DFO – distillated fuel oil. Source: EIA Electric Power Monthly 2022.

3.2.5 System Load

System-level hourly load and hourly electricity generation by fuel types in both PJM and MISO are drawn from [11]–[13]. The sum of electricity generation across all fuel types does not equal system-level load in the same hour because of energy exchange with neighboring balancing authorities. As shown in Figure 7, PJM constantly generates 5% to 15% more electricity than its system-level demand, implying that the system-level demand is met by generators in both PJM and neighboring BAs. Consequently, we use the sum of electricity generation across all fuel types as the demand in our analysis. The total electricity generation ranges from 60 to 150 GW in PJM, and 70 to 120 GW in MISO. In addition, we use net demand (i.e., gross demand net electricity generation from non-dispatchable resources such as wind, solar, and hydro) in the calculation of marginal cost of electricity, assuming that non-dispatchable resources are used first because of their zero marginal cost.

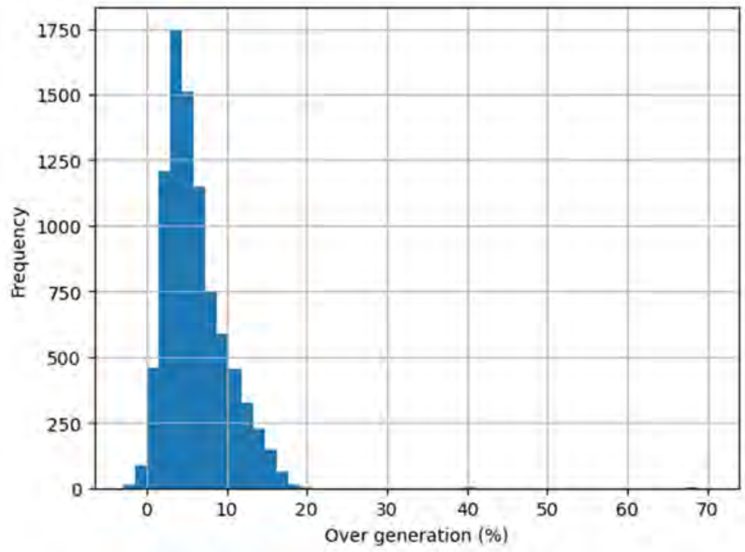


Figure 7. Histogram of percentage of electricity generation in excess of system-level demand in the PJM region.

3.3 Results

3.3.1 Analyzed Scenarios

As a screening analysis, this study started by looking into the economic, environmental, and reliability impacts of retirement of all nuclear units in PJM and MISO. We examine these two areas because in 2022, nuclear power represents 35% and 12% of existing capacities in PJM and MISO respectively, greater than any other balancing authorities in the U.S. We include two scenarios: (1) a business-as-usual (BAU) scenario where all units work in nominal conditions and, (2) a worst-case scenario where all nuclear units are assumed to be offline. These two scenarios are likely to act as a bounding analysis, where the worst-case scenario reflects the extreme case when all nuclear units retire without replenishment. Although the worst-case scenario is unlikely to occur because of the addition of new capacities, our screening analysis lays the foundation for more rigorous analyses during our next stage.

3.3.2 Economic Impacts

The supply curves of PJM are shown in Figure 8. These curves represent the marginal cost to produce the next increment of electricity in each region. As demand for electricity increases, the cost of generating it rises because more expensive units must be dispatched. The marginal cost of the BAU scenario stays close to 0 $/MWh before demand reaches approximately 35 GW (i.e., the capacity of all existing nuclear units in PJM), indicating nuclear units are dispatched first because of their extremely low marginal cost. By contrast, when all nuclear units are offline, the supply curves start from approximately 25 $/MWh in the worst-case scenario, which represent marginal costs of other baseload units (e.g., coal-fired power plants or NG-combined cycle units). Similarly, Figure 9 shows a comparison between the BAU and the worst-case scenarios, reflecting the economic impact of removing all nuclear units.

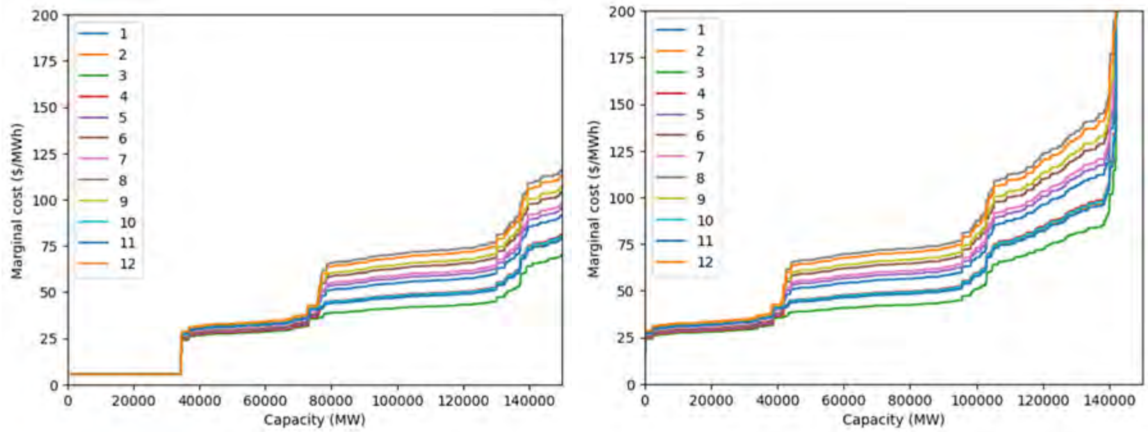


Figure 8. Supply curves of the PJM region by month of the BAU scenario (left) and worst-case scenario (right). Note that the curves are capped at 200 $/MWh for readability. Only the capacity of dispatchable resources (i.e., thermal units) in the supply curve was included.

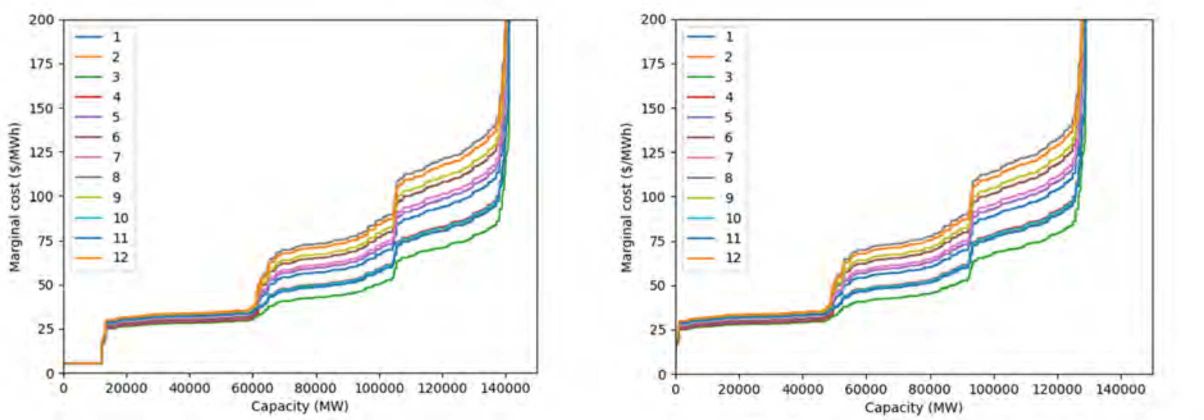


Figure 9. Supply curves of the MISO region by month of the BAU scenario (left) and worst-case scenario (right). Note that the curves are capped at 200 $/MWh for readability. Only the capacity of dispatchable resources (i.e., thermal units) in the supply curve was included.

After applying the supply curves to hourly system-level net load, the hourly marginal costs of electricity in PJM and MISO are shown in Figure 10 and Figure 11, respectively. Both markets present similar yearly trends, where marginal costs are more expensive in summer and winter, because of greater demand in both seasons. In both markets, losing all nuclear units leads to a systematic elevation of electricity generation costs. A visual inspection of hourly marginal costs indicates that the maximum marginal cost in PJM rarely exceeds 75 $/MWh in the BAU scenario, as opposed to over 125 $/MWh in the worst-case scenario. Similarly, the maximum marginal cost increases from 75 $/MWh to over 120 $/MWh in MISO. On average, the marginal costs range from 20 to 80 $/MWh in PJM and from 20 to 60 $/MWh in MISO in the BAU scenario, as opposed to 40 to 140 $/MWh in PJM and 50 to 90 $/MWh in MISO in the worst-case scenario. The distributions of marginal cost also suggest similar trends; distribution of the worst-case scenario shows a fatter tail on the right, indicating greater probability of higher marginal costs. The BAU distribution in MISO shows a high and narrow peak in the range of 25 to 40 $/MWh, suggesting that marginal cost has a greater probability of falling in this range. By contrast, the worst-case scenario presents a low and wide plateau between 30 and 75 $/MWh, implying elevated marginal costs.

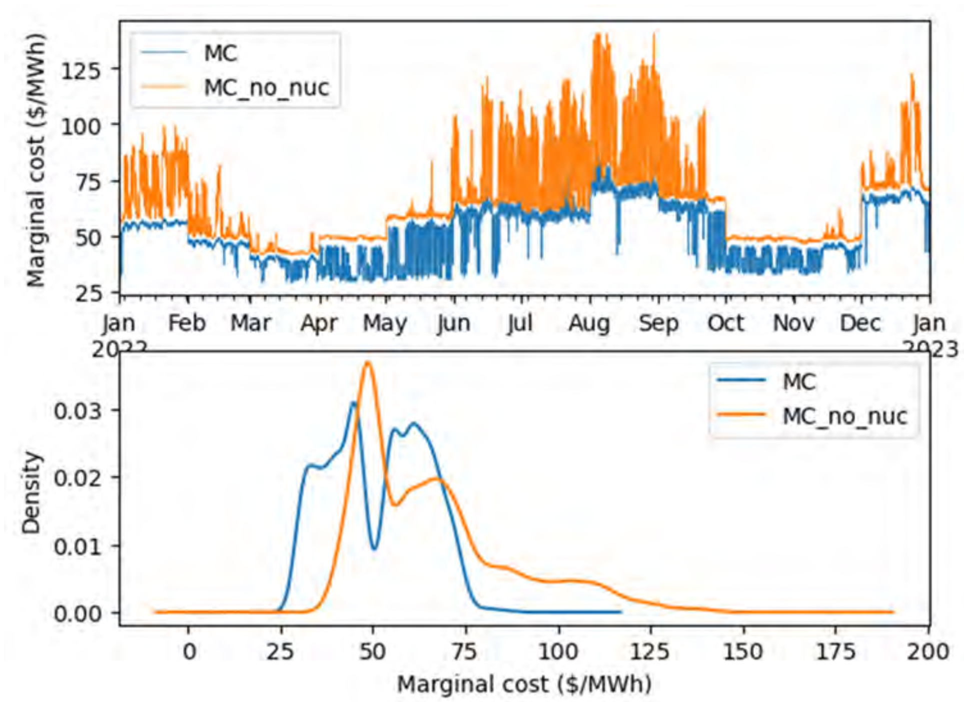


Figure 10. Marginal costs (MC) of electricity in PJM. Top: Hourly marginal cost. Bottom: Probability distributions of hourly MC. MC: the BAU scenario, MC_no_nuc: the worst-case scenario.

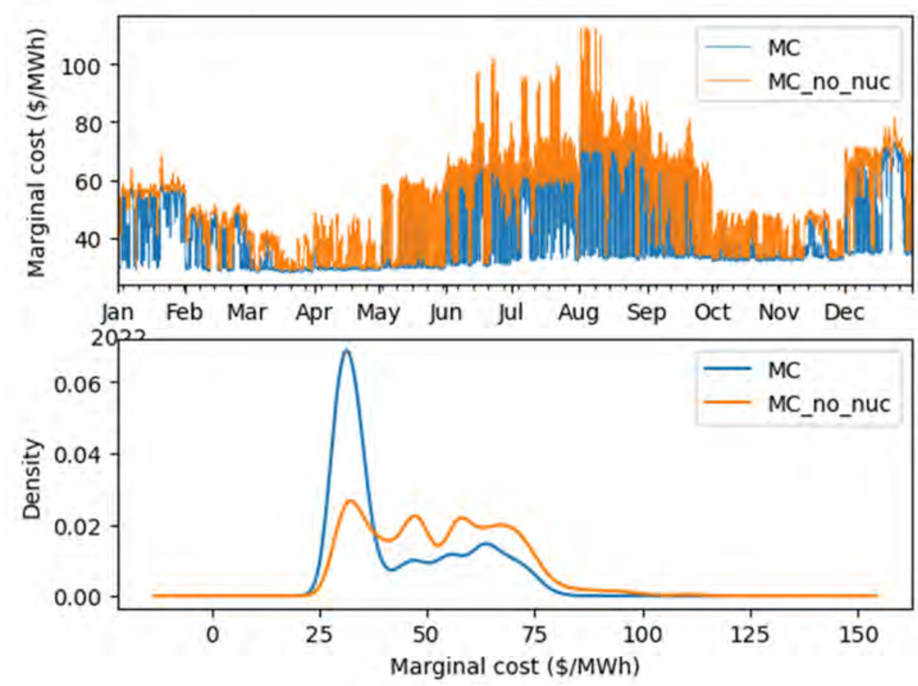


Figure 11. Marginal costs of electricity in MISO. Top: Hourly marginal cost. Bottom: Probability distributions of hourly marginal costs. MC: the BAU scenario, MC_no_nuc: the worst-case scenario.

3.3.3 Environmental Impacts

The environmental impacts of removing all nuclear units are displayed in Figure 12 and Figure 13. Similar to the trends of MCs, emissions in both markets present similar trends—where summer and winter see greater hourly emissions—because of our simplified assumption that emissions are linearly proportional to electricity generation. In both markets, losing all nuclear units leads to elevated CO_2 emissions levels, as can be reflected by increased hourly emission rates.

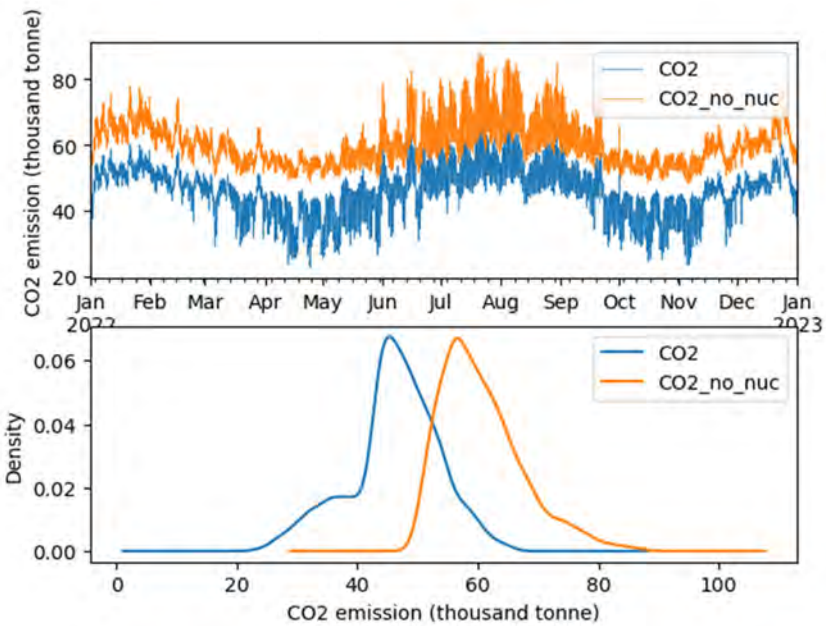


Figure 12. System-level CO_2 emissions in PJM. Top: Hourly emissions. Bottom: Probability distributions of hourly emissions. CO_2: the BAU scenario, CO_2_no_nuc: the worst-case scenario.

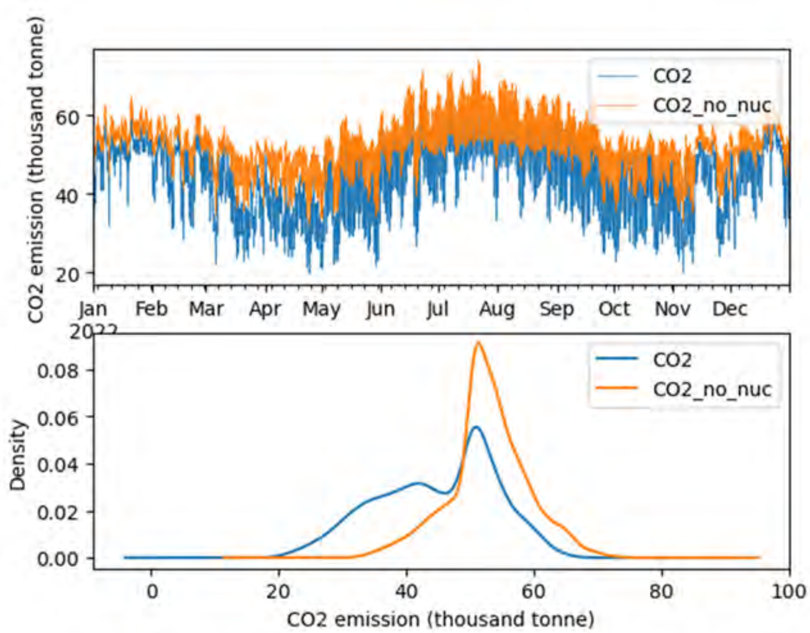


Figure 13. System-level CO_2 emissions in MISO. Top: Hourly emissions. Bottom: Probability distributions of hourly emissions. CO_2: the BAU scenario, CO_2_no_nuc: the worst-case scenario.

3.3.4 Reliability Implications

After repeating the Monte Carlo simulation 10,000 times, the results of our reliability analysis for PJM and MISO are presented in Figure 14 and Figure 15, respectively. Both figures show LOLP and EUE as a function of time. The BAU scenario in PJM shows zero loss-of-load incidents, as reflected by the flat LOLP and EUE curves; therefore, the LOLH and annual EUE are both zero, consistent with the commonly used industry adequacy LOLH standard of 1 day in 10 years. By contrast, the worst-case scenario displays much greater LOLP and EUE, suggesting frequent loss-of-load events, especially in summer and winter where load tends to be higher. The resulting total LOLH and annual EUE are 329 hours/year and 2,044 GWh, significantly exceeding industry standards, implying a severe shortage of generating resources and insufficient adequacy levels.

In MISO, although the BAU scenario shows non-zero LOLP and EUE, the total LOLH and EUE are 0.001 hours/year and 2 MWh, respectively, still within tolerance of industry reliability standard. Similar to PJM, losing all nuclear units also result in elevated LOLP and EUE levels, resulting in a total of 2.6 hours/year of LOLH and 4,084 MWh of EUE. Although the worst-case scenario in MISO presents better results than PJM in terms of reliability metrics, the results still suggest insufficient adequacy level, as reflected by its failure to comply with reliability standard.

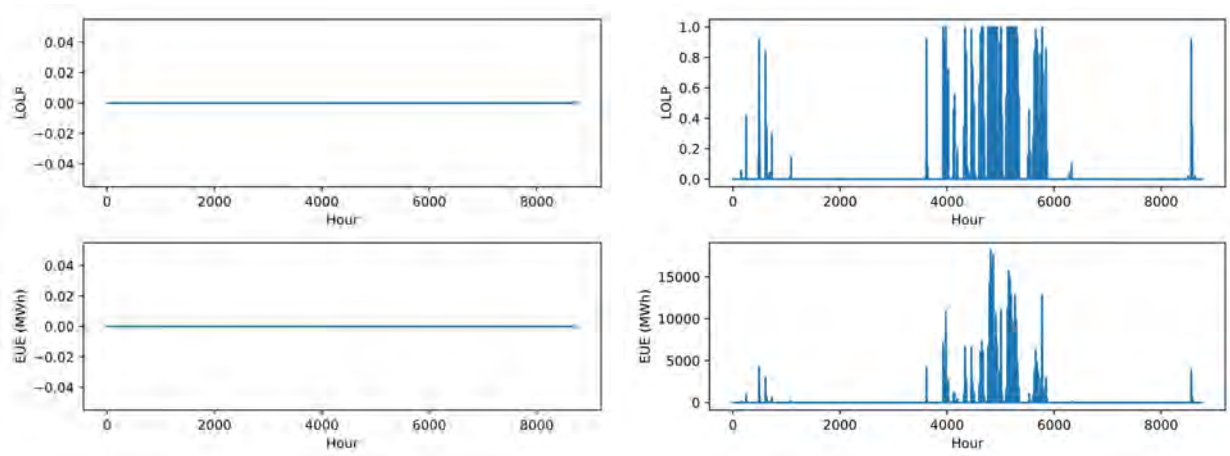


Figure 14. Reliability metrics in PJM: Hourly LOLP and EUE of the BAU scenario (left) and the worst-case scenario (right). Note that different y-axis scales are used for better readability.

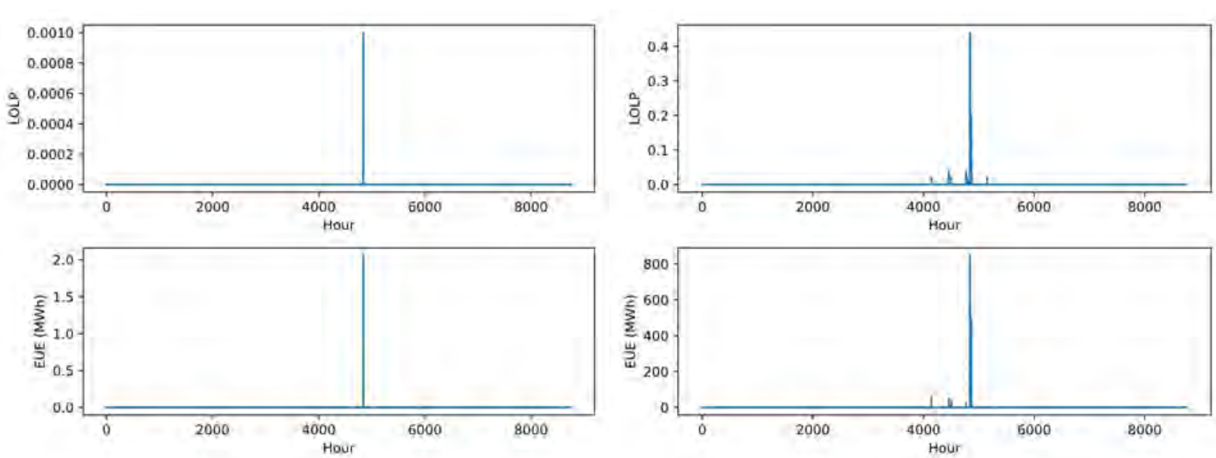


Figure 15. Reliability metrics in MISO: Hourly LOLP and EUE of the BAU scenario (left) and the worst-case scenario (right). Note that different y-axis scales are used for better readability.

3.4 Conclusion

Our rapid-analysis method for early retirement of nuclear plants in PJM and MISO suggest the following insights.

- Both markets (PJM and MISO) indicate significant economic, environmental, and reliability impacts by removing all nuclear units:
  - Electricity prices increase by up to $50/MWh. The maximum MCs in both PJM and MISO increase from 75 $/MWh to over 120 $/MWh.
  - Hourly CO_2 emissions increased by 20 kt/h.
  - LOLH increased from 0 to over 300 hours/year in PJM, and from 0.001 hours/year to 2.6 hours/year in MISO, where a commonly used industry reliability standard LOLH is 1 day in 10 years.
  - Losing all nuclear units results in greater impact on PJM, due to greater nuclear capacity share. In 2022, the nuclear penetration levels in PJM and MISO are 35% and 12%, respectively.
- Losing all nuclear units without replenishment is extremely unlikely, and our rapid analysis can only be used as a bounding analysis. Results of early retirement or extended forced outage are likely in between the BAU and worst-case scenario.

This analysis represents a highly simplified analysis, yet its results are insightful in terms of the impact of retirement of nuclear units. Major caveats include neglecting transmission network constraints, exclusion of a small percentage of thermal units (5% in PJM and 7% in MISO), and simplified market operation rules. Specifically, our analysis assumes a “copper-plate” model of transmission network by intentionally neglecting power flow constraints of transmission networks. In addition, we only consider energy markets in the rapid analysis with extremely simplified operation constraints, whereas real-world markets include ancillary markets and additional operation rules (e.g., unit commitment constraints and ramp rate constraints). Although this enables fast evaluation, details of transmission constraints can affect our results; therefore, the following section will use a more sophisticated production cost model for detailed analysis. The exclusion of some thermal units is unlikely to cause systematic bias in our results because most of the neglected units are less efficient and are very expensive; therefore, the units are often used for peaking purpose and have very low-capacity factors.

4. PRODUCTION COST MODEL (PCM) ANALYSES OF NUCLEAR AVAILABILITY IN WI and EI

4.1 Introduction

The objective of this section is to investigate the impact of different nuclear plant availability and extreme weather conditions using a production cost modeling (PCM) simulation. PCM considers the physical and temporally dependent limitations of the transmission network, and generators. The objective of the PCM is to minimize the total cost of producing electricity while satisfying demand and meeting the reserve requirements. The PCM is leveraged to evaluate the power system behavior under distinct predefined conditions. In Section 4.2, we present the methodology and datasets used in this work. In Section 4.3, we comprehensively describe the modeling inputs of GridView and designed scenarios. In Section 4.5 and 4.6, we present the results of PCM simulation for the WI and EI respectively. Section 4.5 presents a comparative analysis of WI and EI.

4.2 Methodology

4.2.1 Evaluated Threats and Implications

The following threats are considered and their impacts on the power system will be analyzed in the simulation: nuclear maintenance schedules, heat waves, and hydropower droughts. Nuclear maintenance schedules, including possible extensions, will affect the availability of specific nuclear units throughout the simulation. The impacts of heat waves and hydropower droughts on the power system will be detailed in Subsections 4.2.1.2 and 4.2.1.3 respectively.

4.2.1.1 Nuclear Maintenance Schedules

Typical maintenance outages at nuclear power plants involve a series of planned activities aimed at ensuring the safe and reliable operation of the facility. Outages are carefully planned and scheduled to minimize the impact on electricity generation. In the United States, for example, nuclear power plants typically schedule their outages for the spring and fall, when electricity demand is lower. The United States Nuclear Regulatory Commission provides historical power reactor status report available to the public. The historical power reactor status report form the year 2005 to the year 2022 have been collected from Nuclear Regulatory Commission’s 2023 status report [14]. A pattern of refueling and maintenance schedule is observed for most units. The two common maintenance cyclical schedule behavior is 18 months and 24 months.

Leveraging the historical information, the average number of maintenance days for the 92 units available is computed for spring and fall maintenance days. Table 5 presents the maximum, 75 percentile, median, 25 percentile, and minimum average number of maintenance days for the nuclear units in the EI, WI, and ERCOT. The nuclear capacity unavailable given nuclear maintenance for the U.S., EI, WI, and ERCOT is presented in Figure 16. The generated expected maintenance capacity, derived from the average number of maintenance days for each unit considering the difference for the spring and fall, aligns with anticipated periods of lower demand.

Table 5. Nuclear units’ distribution of the average number of maintenance days for EI, WI, and ERCOT for spring and fall maintenance periods.

Maintenance Days	Spring			Fall		
	EI	WI	ERCOT	East	WI	ERCOT
Maximum	62	52	49	62	44	44
75 percentiles	46	47	39	46	44	41
Median	38	37	34	39	44	37
25 percentiles	32	35	32	30	43	34

Maintenance Days	Spring			Fall		
	EI	WI	ERCOT	East	WI	ERCOT
Minimum	11	33	30	18	36	34

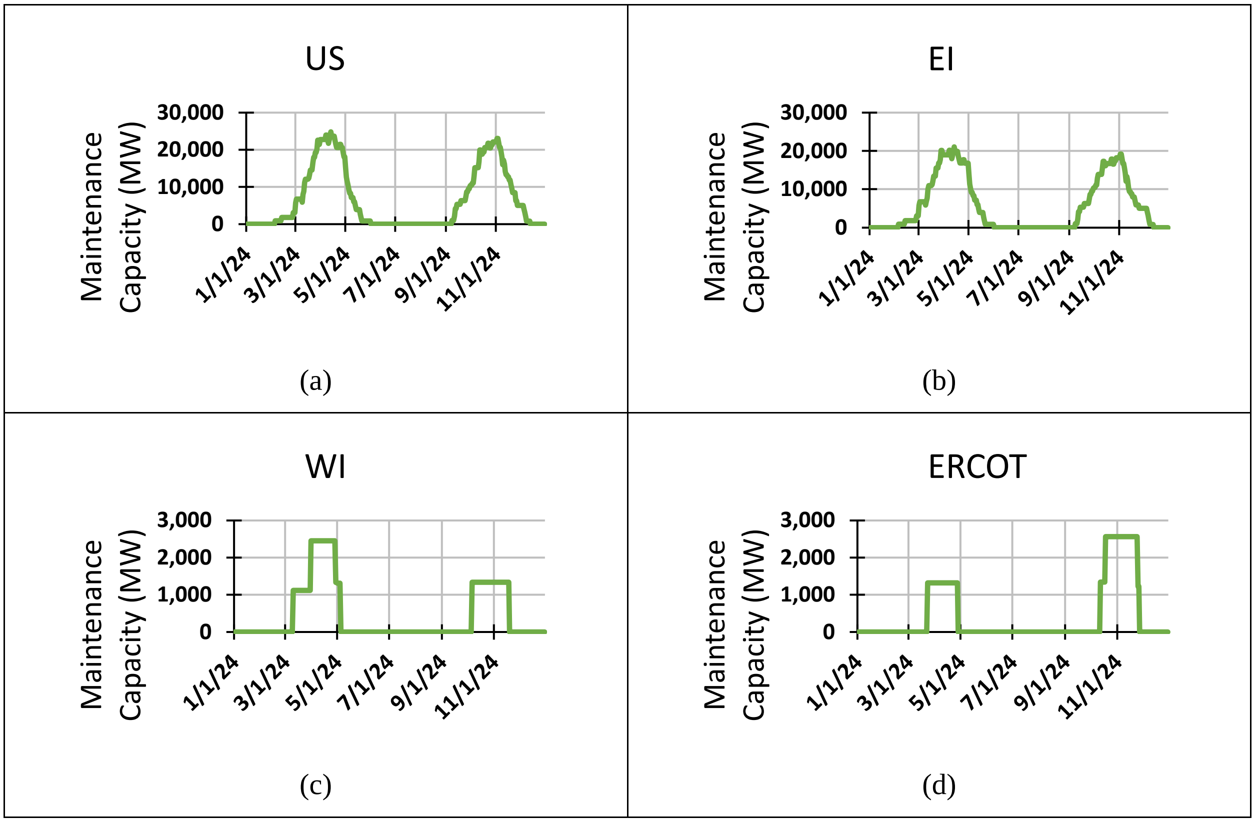


Figure 16. Nuclear capacity undergoing maintenance generated for the 2024 year given the average historical behavior of the units. A, b, c, and d represent the U.S., EI, WI, and ERCOT, respectively.

Leveraging the historical characteristics of the maintenance schedule, future maintenance schedules are created considering extended maintenance. The extended maintenance intends to characterize challenges in bringing the unit into operation (e.g., the EPA rule [86 FR 880]). The chosen number of days for extended maintenance is 90 days. The capabilities of generating nuclear power plant maintenance schedules are generic for any region being made based on the individual unit historical maintenance scheduled.

4.2.1.2 Heat Wave

Heat waves pose significant challenges to the electrical grid by simultaneously increasing electricity demand—primarily due to heightened requirements for space cooling—and reducing supply through generator derating and decreased transmission and distribution system efficiency [15], [16], [17], [18], [19]. Given their widespread spatial coverage, heat waves impact vast regions of the electric grid concurrently [20]. This dual impact emphasizes the critical role of the transmission system in mitigating stress during extreme heat events. Furthermore, the combination of heat waves with drought conditions can lead to significant risks of shortfall [21]. The implications of thermal generation derating due to heat wave for the WI is presented in [19]. The authors estimated a small derating for the WI units given the small number of open-loop cooled facilities, estimating the generation capacity reduction between 1.1% and 3.0%. The transmission capacity available for power lines in California has a derating on an average of 7.5% given a temperature increase of 9°F for the hot days in August in [15]. The report also explores increased losses for transmission and distribution and reduced rating of substations, among other topics with a focus on estimating the risk to California (CA) power system infrastructure for projected future climates.

Solar generation experiences efficiency losses during heat waves as the temperature rises, affecting the output of solar panels. Efficiency typically decreases by −0.2 to −0.47%/°C, depending on the panel type [22]. Similarly, heat waves influence wind generation, with effects varying meteorologically and regionally. Meteorological phenomena like heat domes, for instance, can induce extreme heat and suppress wind generation [23]. However, the wind response during extreme heat is subject to regional and meteorological variability.

To illustrate the temporal and geographical characteristics of distinct heat wave events, consider two contrasting historic heat wave events in the western U.S. The first, spanning from June 25 to July 2, 2015, affected much of the western U.S. region, including the Pacific Northwest (NW) (see Figure 17). The second event, occurring from July 22nd to July 28th, 2018, was particularly intense in CA and the Desert Southwest (DSW) (see Figure 18).

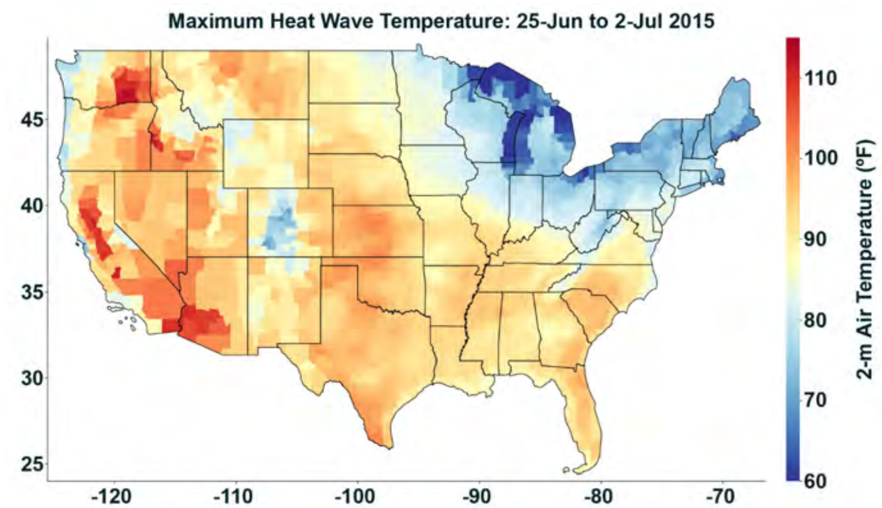


Figure 17. 2015 heat wave event in the Pacific Northwest. Temperatures in eastern Washington exceeded 112°F during this event. Well above average temperatures extended across much of the West [24].

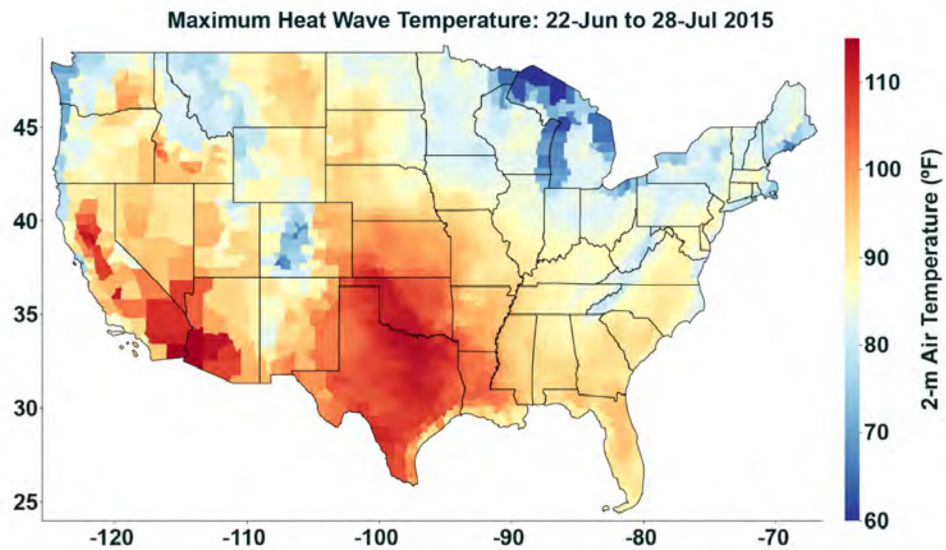


Figure 18. 2018 heat wave event in California and the Desert Southwest. This event was more localized to the central California valley and Desert Southwest, where maximum temperatures exceeded 110°F [24].

The weather conditions during extreme events is evaluated using the Thermodynamic Global Warming dataset generated by the Integrated, Multiscale, Multisector Modeling (IM3) project [25]. This dataset provides 40 years of historical hourly meteorological data (1980–2019) at a 12 km spatial resolution. The historical record spanning 40 years is regarded as cyclical and extrapolated into the future, accounting for diverse levels of additional warming applied to the boundary conditions of the Weather Research and Forecasting model utilized for dynamically downscaling meteorological data. The additional warming data is derived from the Representative Concentration Pathway [RCP] 8.5 [26] and using averages for climate models that are colder and hotter than the multi-model mean. Utilizing the described thermodynamic global warming approach, we investigate how these events may evolve under climate change scenarios [25].

The main consideration regarding a heat wave event is its impact on the system load. The procedure to generate the load for a heat wave scenario is:

1. Create the climate conditions as described.
2. The Total Electricity Loads (TELL) open-source model developed by IM3 is leveraged for generating the load considering the climate event condition [27]. TELL operates by receiving hourly time-series meteorological data from a BA and subsequently simulating the hourly evolution of total electricity demand within the BA in response to weather.
3. TELL can also grow the generated load for given climate conditions to represent the year of interest. The total energy for the year is adjusted to match with or without an event.

4.2.1.3 Hydropower Droughts

Hydropower drought or hydrological drought refers to a prolonged period with below-average water availability in rivers, lakes, and reservoirs leading to reduced hydroelectric power generation capacity. Low precipitation results in decreased inflow into reservoirs and rivers. This can have significant impacts on energy production, as hydropower is reliant on the flow of water to turn turbines and generate electricity. The combination of heat waves with drought conditions can lead to significant risks of shortfall [21]. Higher temperatures increase water evaporation, further reducing the already limited availability of water.

The Western U.S. is a region of extreme climate variability subject to significant fluctuations in the yearly rainfall and snow accumulations to generate hydropower. Reduced water availability during drought years can lead to significant reductions in maximum hydropower capacity, especially in the WI system, requiring the system operator to find alternative energy to maintain grid reliability. Periods of peak demand in the Western U.S. tend to occur during the summer, which coincides with depleted mountain snowpack levels and a higher likelihood of water scarcity.

During the last two decades the WI's hydropower has been characterized by high volatility with more frequent and intense periods of drought as compared to the 20th century. From a historical perspective, drought has had a measurable impact on hydropower production in the WI system. However, the extent and character of that impact depends on the scale at which effects are evaluated. Figure 19 shows combined western hydropower production for the 21st century, and the year 2001 shows the most severe drought, with a hydropower reduction of 21%. The 2001 drought began with exceptionally low precipitation and snow accumulation in the fall and winter of 2000, leading to near record-low springtime flows in the Columbia River, which is home to approximately two-thirds of western hydropower generating capacity [28].

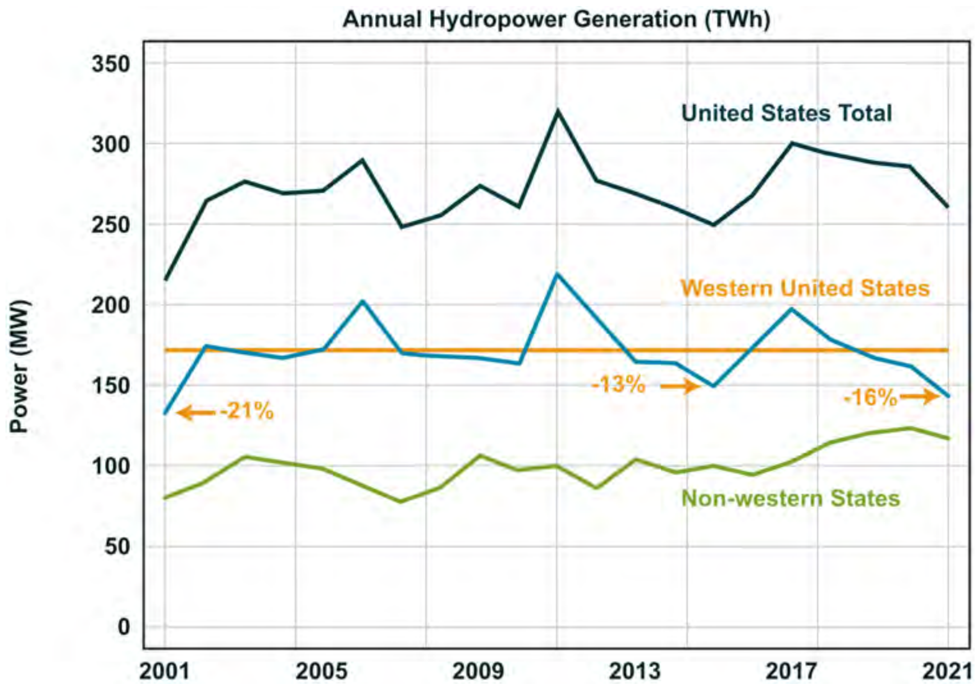


Figure 19. Total hydroelectric power generation in the U.S. Percentage values in parentheses give deviation from mean annual western generation (dashed line). (Data source: EIA state-level generation reports) [29].

Weekly hydropower constraint data, known as the HydroWIRES B1 data, were developed based on the RectifHyd dataset [30]. RectifHyd was developed to correct inaccuracies in the EIA-923 monthly generation data. RectifHyd contains monthly power generation estimates for 1,500 hydropower plants that are disaggregated from annual EIA-923 power generation data using observed streamflow and power production data. The derived B1 data disaggregate the monthly hydropower data to weekly and provide weekly constraints (minimum operating capacity, maximum operating capacity, energy targets, etc.) for each of these hydropower plants using observed hydropower data. These data are designed for use in a PCM.

4.2.2 Quantifying Power System Reliability Performance

4.2.2.1 Unserved Load

Resource adequacy is defined by NERC as “the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements” [31]. Resource adequacy is often measured by the metrics of an unserved load (also referred to outage) due to an insufficient energy supply. Previously we discussed the potential threats, such as nuclear maintenance, heat wave, and drought, to bulk systems. The considered alteration to the system given the nuclear maintenance and drought is the energy supply, while a heat wave will affect the demand. Thus, the unserved load is the main metric to measure the system reliability. The default unit of unserved load is MWh in GridView. The average U.S. household energy consumption is leveraged to estimate the number of homes affected by the outage.

4.2.2.2 Reserve Shortage

Extended maintenance schedules of nuclear units and other extreme conditions have also raised concerns about how we maintain system reliability, including how many reserves are procured and from where. Fewer amounts of energy supply and more energy demand increases the complexity of the system since the gap between reduced supply and increased demand must be bridged by other types of generation. This can lead to an increase in reserve requirements—particularly the potential for increased expensive reserves. The reserves requirements are modeled as ancillary services (AS) input in GridView, that include flexible up/down, regulation up/down, and spinning reserve requirements, while the actual served amount is the GridView output. The reserve shortage is another metric to quantify the system performance, which is measured by the difference between the reserve requirements and actual deployments, and a higher reserve shortage value indicates a more stressed grid condition.

Another alternative for assessing the reserve shortage is to consider the NERC standard [32]. The standard identifies four violation severity levels (VSL) that are evaluated for every clock hour in relation to the portion of the required reserved that was not served. The VSL are "Severe", "High", "Moderate", and "Lower" having served less than 70%, 80%, 90%, and 100% respectively.

4.2.2.3 Generation Mix Change and Variable Generation Curtailment

The generation mix refers to the combination of fuels used to produce energy in the bulk system. It is dominated by NG and hydro in the current WI system. In addition, variable generation curtailment is expected to happen with the massive installed capacities of solar and wind in the WI system. Curtailment is calculated by subtracting the energy that was actually produced from the amount of electricity forecasted to be generated. In this work, generation mix, and curtailment are expected to change over the designed scenarios due to nuclear maintenance schedules and weather conditions.

4.2.2.4 Greenhouse Gas Emission

Greenhouse gases (GHG) trap heat and make the planet warmer. The largest source of GHG emissions from human activities in the U.S. is from burning fossil fuels for electricity, heat, and transportation. Electric power generates about a 25% share of GHG emissions and includes emissions from electricity production used by other end-use sectors [33]. In GridView outputs, CO_2, NOX, and SO_2 are the GHG emissions mainly from thermal generators such as coal and NG units.

4.2.2.5 LMPs

Locational marginal price (LMP) is defined as the marginal price for energy at different locations where energy is delivered or received and is based on forecasted system conditions and the real-time security constrained economic dispatch. LMP is a pricing approach that addresses transmission congestion and loss costs, as well as energy costs. Therefore, an energy customer pays an energy price that includes the full marginal cost of delivering an increment of energy to the buyer's location. LMP provides valuable insight to system planners as to the stressed transmissions in the system and the potential economic benefits of nuclear units. In GridView outputs, LMP is another metric to monitor the areas where nuclear units are under maintenance.

4.3 Description of Production Cost Model Base Case

PCMs are particularly suitable for modeling the physical grid assets of large power grids such as the U.S. Interconnections. PCMs determine the optimal unit commitment schedule and unit dispatch that minimizes overall costs while satisfying demand within system-level limits, such as operating reserve reliability, and unit-level limits, including technical minimums, maximums, and ramping constraints. In PCM, the costs largely consist of fuel costs, variable operating and maintenance costs, and start-up/shut-down costs. Most of these costs are incurred at thermal generators. The main purposes of PCMs are to:

- Mimic electricity market operations
- Identify periods of unserved energy and transmission congestion (reliability)
- Calculate spot prices at buses and shadow prices on lines
- Dispatch generators to minimize the production cost given unit characteristics (cost, as well as physical) and chronological load
- Perform a dispatch such that transmission line limits are not violated under normal, as well as contingency conditions.

Generally, the inputs of PCM include load, hourly resources, generation, and transmission/paths, the outputs of interests include operation costs, generation dispatch, power flow congestions, renewable curtailment, prices, emissions, and unserved load such as shown in Figure 20. WI uses GridView as its PCM tool. It uses probability distributions for equipment outages during a sequential mode of hour-by-hour simulations, and typically for 8,760 hours in a year [34]. The selection of testing conditions is emulated through a random sampling. To obtain accurate risk indices, many simulations will have to be performed. In general, the simulations provide outputs on production cost, transmission congestions, and other reliability indices.

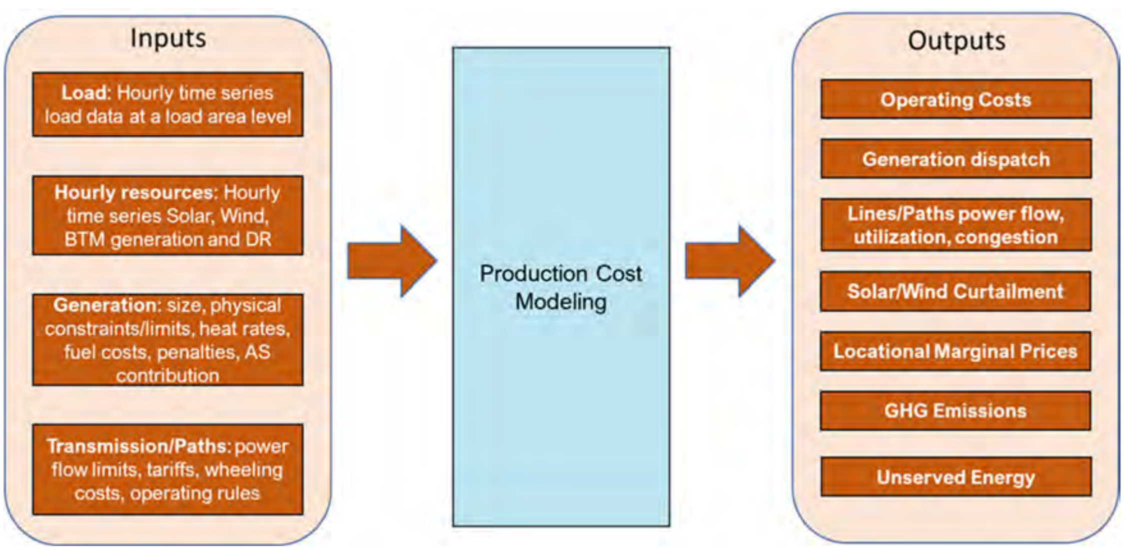


Figure 20. Overview diagram demonstrating the various factors like load, hourly resources, generation, and transmission are used as inputs for a production cost modeling simulation to determine the unit commitment and generation dispatch.

4.3.1 WI PCM Model

The ADS is designed to be analyzed with PCM [35]. The 2030 Anchor Data Set (ADS) PCM represents the expected loads, resources and transmission topology 10 years in the future from a given reference year. Western Electricity Coordinating Council (WECC)'s 2030 ADS is based on a reference year of 2020, so it represents loads, resources and transmission topology in 2030. There are 38 functional BA in the WI, with a detailed nodal representation of the WI power grid topology including about 22 K nodes and 26 K transmission lines.

In this work, the base case is built from WECC's 2030 ADS, which includes existing transmission paths, load profiles, and generation dispatch schedules. The 2030 ADS is modified to be with four nuclear plants online, including Diablo Canyon Power Plant (DCPP), Columbia Generating Station, Palo Verde Generating Station, and Antelope Valley Station [36]:

DCPP is a nuclear power plant near Avila Beach in San Luis Obispo County, CA. The plant has two reactors operated by Pacific Gas and Electric. It produces about 18,000 GWh of electricity annually (8.6% of total CA generation and 23% of carbon-free generation), supplying the electrical needs of more than three million people [37]. It should be noted that the planned decommission year of DCPP is 2030; however, it is modified as in-service in this ADS 2030 base case.

Columbia Generating Station is a commercial nuclear energy facility located on the Hanford Site in Washington. It is owned and operated by Energy Northwest, a Washington state, not-for-profit joint operating agency. Columbia planned generation is about 9 million MWh annually. The study [38] affirms Columbia's provision of unique, firm, baseload, non-carbon emitting generation with predictable costs for the region's ratepayers.

The Palo Verde Generating Station is nuclear power plant located near Tonopah, Arizona. Of all the nuclear power plants in the U.S., Palo Verde is the highest electricity producer annually and ranks second in rated capacity. It is owned by seven different entities and operated by Arizona Public Service Company. It is a critical asset to the Southwest, generating approximately 32 million MWh annually, which serves about four million people [38].

The Antelope Valley Station is located in Idaho. It is a future-planned nuclear station in 2030 ADS and the commission date starts in the year 2027. It has 12 units, and the aggregated capacity is about 586 MW. The Antelope station's maintenance is not considered in this base case because it is a new facility in 2030 ADS.

The detailed description of these nuclear plants in WI is shown in Table 6, and the locations of BA and plants are shown in Figure 21. Figure 22 presents the geographics areas of the Western Interconnection.

Table 6. WI nuclear units' description.

Name	Unit ID	Bus KV	Status	Area Name	State	Capacity (MW)
DCPP	1	25	Existing	CIPV	CA	1,200
DCPP	2	25	Existing	CIPV	CA	1,200
Columbia	1	25	Existing	BPAT	WA	1,185
Palo Verde	1	24	Existing	TH_PV	AZ	1,333
Palo Verde	2	24	Existing	TH_PV	AZ	1,336
Palo Verde	3	24	Existing	TH_PV	AZ	1,334
Antelope	1	230	Future-planned	PAID	ID	48.88
Antelope	2	230	Future-planned	PAID	ID	48.88

Name	Unit ID	Bus KV	Status	Area Name	State	Capacity (MW)
Antelope	3	230	Future-planned	PAID	ID	48.88
Antelope	4	230	Future-planned	PAID	ID	48.88
Antelope	5	230	Future-planned	PAID	ID	48.88
Antelope	6	230	Future-planned	PAID	ID	48.88
Antelope	7	230	Future-planned	PAID	ID	48.88
Antelope	8	230	Future-planned	PAID	ID	48.88
Antelope	9	230	Future-planned	PAID	ID	48.88
Antelope	10	230	Future-planned	PAID	ID	48.88
Antelope	11	230	Future-planned	PAID	ID	48.88
Antelope	12	230	Future-planned	PAID	ID	48.88

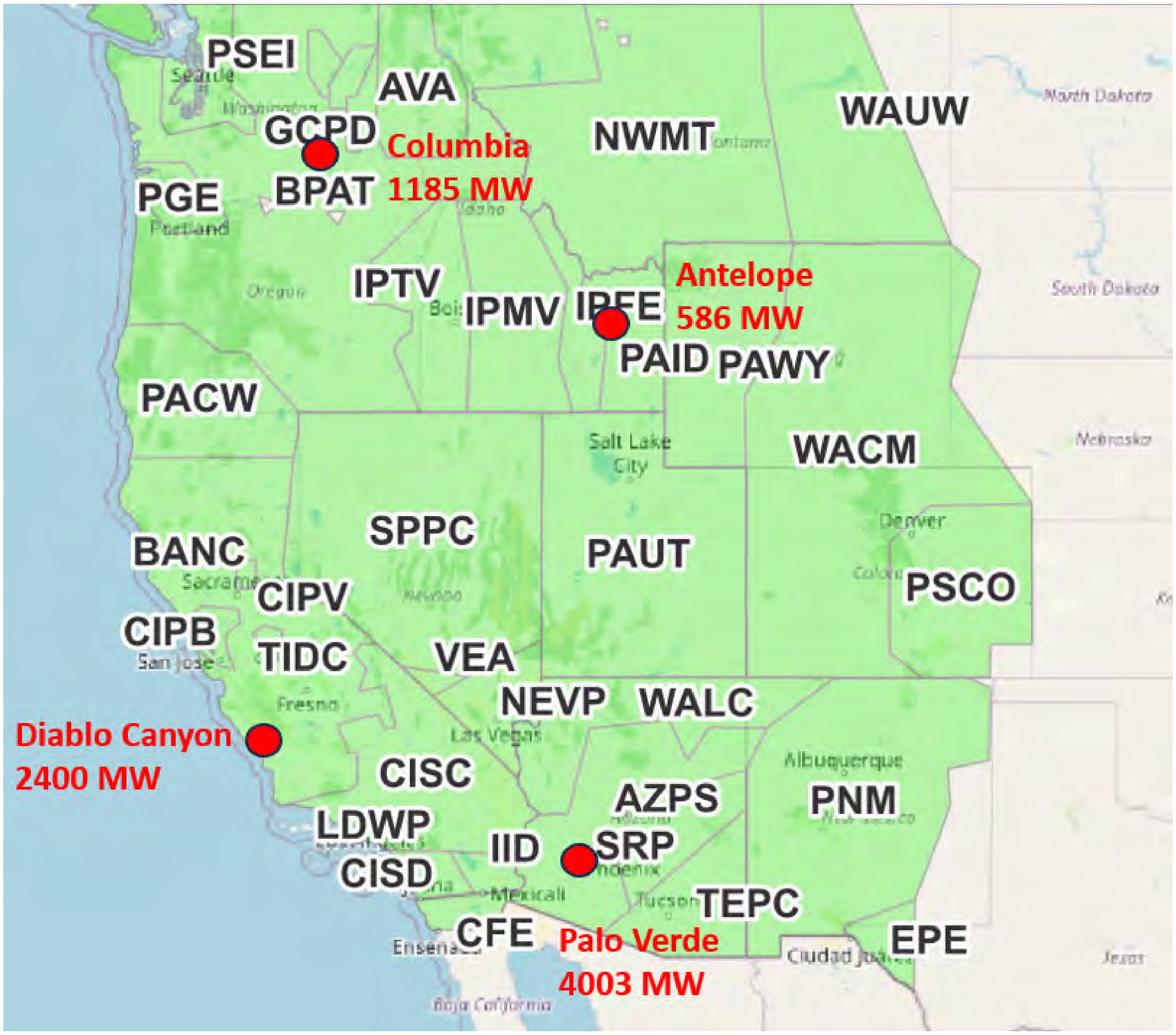


Figure 21. BA and nuclear plant locations in the WI 2030 ADS.

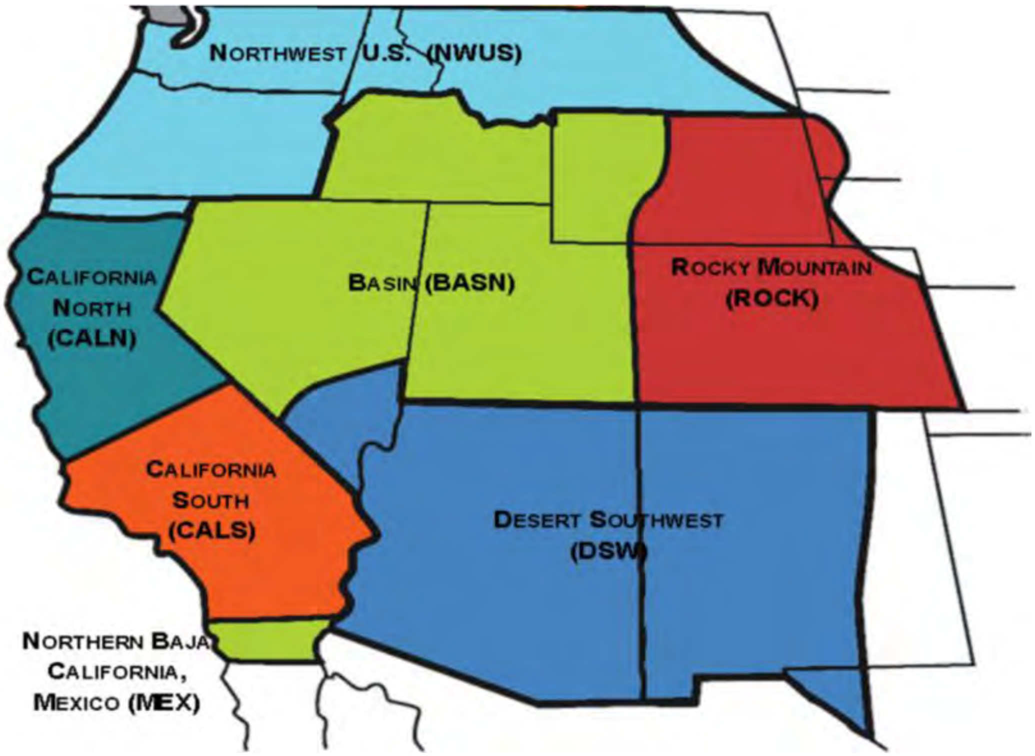


Figure 22. The geographics areas of the Western Interconnection as determined by WI [39].

4.3.2 EI PCM Model

In this section, an approach is utilized to create the EI 2025 PCM case. Starting from the 2031 PNNL EI PCM case was built using the Multiregional Modeling Working Group (MMWG) 2031 Power Flow (PF) Summer 2021 series case as a starting point. The MMWG publishes a library of EI PF cases for members to use [40]. The approach leverages available databases to adjust transmission, load, and generation capacity to reflect 2025 system conditions.

- **Generation:** To adjust generation capacity, we use the existing 2025 MMWG PF Summer case. This entails retiring plants committed after 2025 and reactivating plants which had retired in the 2031 PCM case but were commissioned before 2025. For the thermal units, we adjust the monthly coal and NG fuel prices sourced from the EIA-923 datasets for the year 2024, assuming minimal price fluctuations between 2024 and 2025.
- **Transmission:** Leveraging the 2025 MMWG PF case, we turn offline transmission lines in the 2031 EI PCM case which were committed between 2026 and 2031.
- **Load:** To generate the 2025 load profiles for each EI load area, we initially utilize hourly historic loads from the year 2019 obtained from FERC-714 and PJM data sources. These 2019 hourly loads are then grown using monthly 2025 load forecasts, sourced from publicly available data (e.g., FERC-714, PJM, MISO), to construct the 2025 forecasted hourly profiles. In cases where monthly load forecasts for 2025 are unavailable, we rely on the annual load forecast for 2025. To derive monthly load forecasts from the annual forecast, we construct a unitized monthly shape by analyzing historic monthly peaks spanning 8 years (2013 to 2020). Subsequently, this unitized monthly shape for each load area is multiplied by the annual 2025 forecast to calculate the monthly 2025 load forecast.

The EI Nuclear install capacity is significantly greater than in the WI interconnection. The EI has 86 unclear units and over 100GW installed capacity including Canadian generators. Figure 23 presents the nuclear install capacity in MW for the 2025 EI PCM model across the U.S. by region.

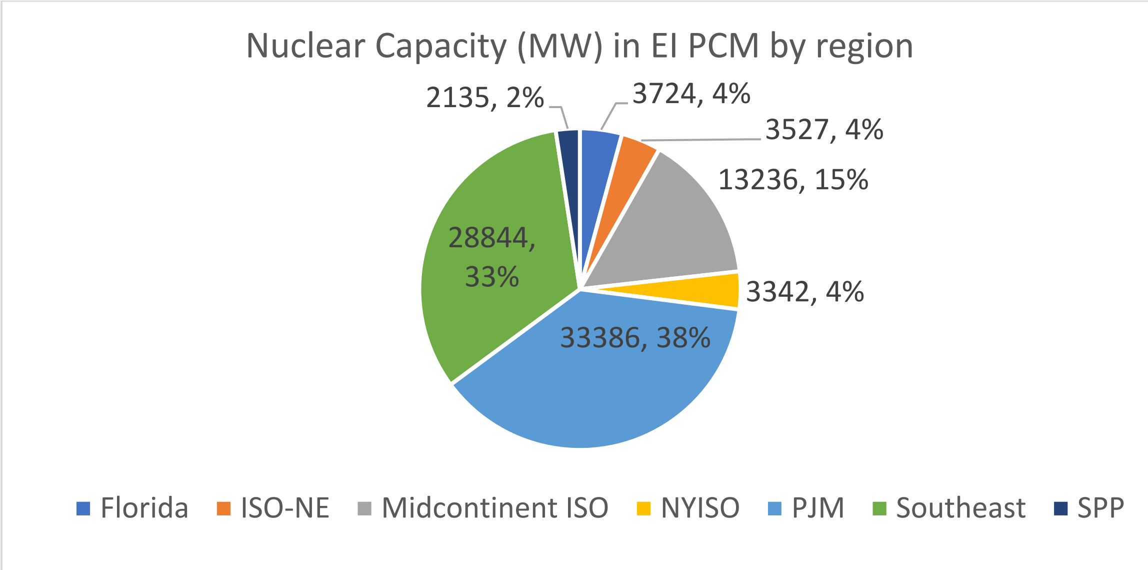


Figure 23. Nuclear capacity (MW) in the 2025 EI PCM by region.

After constructing the 2025 EI PCM case, our objective is to subject it to stress testing similar to the WI. For two designated areas within EI, SERC and Reliability First Corporation, our approach involves formulating a BAU scenario akin to WI Scenario 1. Additionally, we plan to devise two extreme event scenarios, potentially including occurrences like a cold snap or a wind drought event. Through simulating such extreme scenarios, our aim is to comprehensively assess the system's robustness and adaptability, ensuring its capacity to withstand unforeseen challenges and maintain a reliable electricity supply to consumers under different nuclear maintenance schedules. This model and developed use cases will be used to perform similar analysis to the WI case.

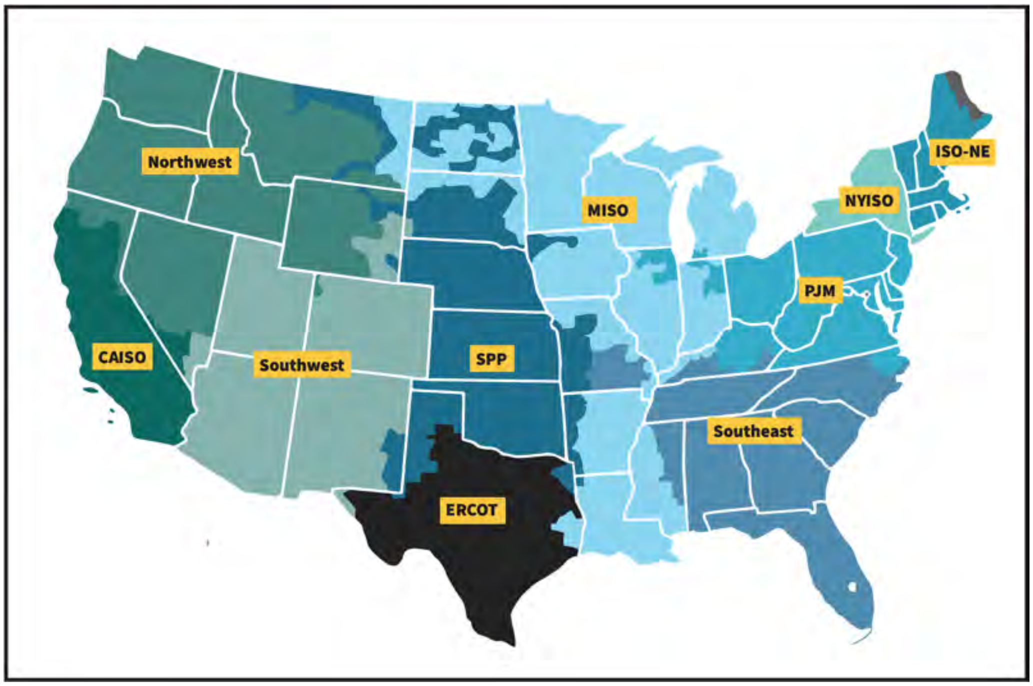


Figure 24. The geographics areas of the national electric power markets as determined by FERC[39].

4.4 Modeling Inputs

4.4.1 Western Interconnection (WI)

4.4.1.1 Nuclear Maintenance Schedules WI

Considering the limited number of nuclear units in the WI region, the considered nuclear availability status ranges from total availability to total unavailability or complete nuclear retirement. Nuclear units as well as most generation units require cyclic maintenance as previously presented. With the historical expected maintenance of the nuclear units the future maintenance schedules are generated and leveraged to create the extend maintenance for nuclear availability status. The considered nuclear availability status are referred to as the schedules:

A. The totality of nuclear units are always available.

B. The totality of nuclear units are always unavailable.

C. Extended maintenance schedule considering 2024.

D. Extended maintenance schedule considering 2025.

Schedule A represents the best-case conditions for nuclear units' availability (i.e., all units available). Schedule B represents the worst possible condition of the nuclear unit's availability (i.e., all units unavailable). Schedule C and Schedule D contain the possible expected extended maintenance for years 2024 and 2025.

Schedule B having none of the units available or all units have been decommissioned, resulting in 71.60-TWh generation loss. Schedule C extended maintenance considering schedule 2024, resulting in 11.07-TWh generation loss. Schedule D extended maintenance considering schedule 2025, resulting in 9.47-TWh generation loss. The Antelope plant is omitted from Schedule C and D due to the lack of maintenance history and the expected minimal impact of its 12 units with 48.88-MW capacity. The maintenance schedules are expected to minimally affect available capacity. Table 7 presents an overview of the WI nuclear units considered for the maintenance Schedule C 2024 and Schedule D 2025. Containing the start and end dates (month/day) of the units and the respective number of days the unit is out of service.

Table 7. WI nuclear maintenance Schedule C 2024 and Schedule D 2025.

Nuclear Resources				Schedule C 2024			Schedule D 2025		
BA	Generator	Plant code	Capacity (MW)	Start	End	Days out	Start	End	Days out
CISO	DCPP 1	6099	1200				5/5	9/23	142
CISO	DCPP 2	6099	1200	3/11	7/30	142			
BPAT	Columbia 2	371	1185				3/15	7/22	130
SRP	Palo Verde 1	6008	1333						
SRP	Palo Verde 2	6008	1336	10/5	12/31	88			
SRP	Palo Verde 3	6008	1334	4/1	8/8	130	1/1	2/19	50

The temporal implications of the maintenance schedules are presented from Table 8 to Table 11 the Schedules A, B, C, and D, respectively. The energy generation loss is computed by multiplying the nameplate capacity by the number of hours the respective units are not available. The maintenance and extended maintenance during months the WI region observe significant demand can place additional challenges in the system to supply the system demands and reserves.

Table 8. Nuclear energy generation loss monthly and total for Schedule A.

Schedule A	Energy generation loss (TWh)												
Generator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DCPP 1	–	–	–	–	–	–	–	–	–	–	–	–	–
DCPP 2	–	–	0.6	0.9	–	–	–		–	–	–	–	1.5
Columbia 2	–	–	–	–	–	–	–	–	–	–	–	–	–
Palo Verde 1	–	–	–	–	–	–	–	–	–	–	–	–	–
Palo Verde 2	–	–	–	–	–	–	–	–	–	0.9	0.5	–	1.4
Palo Verde 3	–	–	–	1.0	0.3	–	–	–	–	–	–	–	1.3
Total	–	–	0.6	1.9	0.3	–	–	–	–	0.9	0.5	–	4.2

Table 9. Nuclear energy generation loss monthly and total for Schedule B.

Schedule A	Energy generation loss (TWh)												
Generator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DCPP 1	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	10.5
DCPP 2	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	10.5
Columbia 2	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	10.4
Palo Verde 1	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	11.7
Palo Verde 2	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	11.7

Palo Verde 3	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	11.7
Total	5.6	5.1	5.6	5.5	5.6	5.5	5.6	5.6	5.5	5.6	5.5	5.6	66.5

Table 10. Nuclear energy generation loss monthly and total for Schedule C 2024.

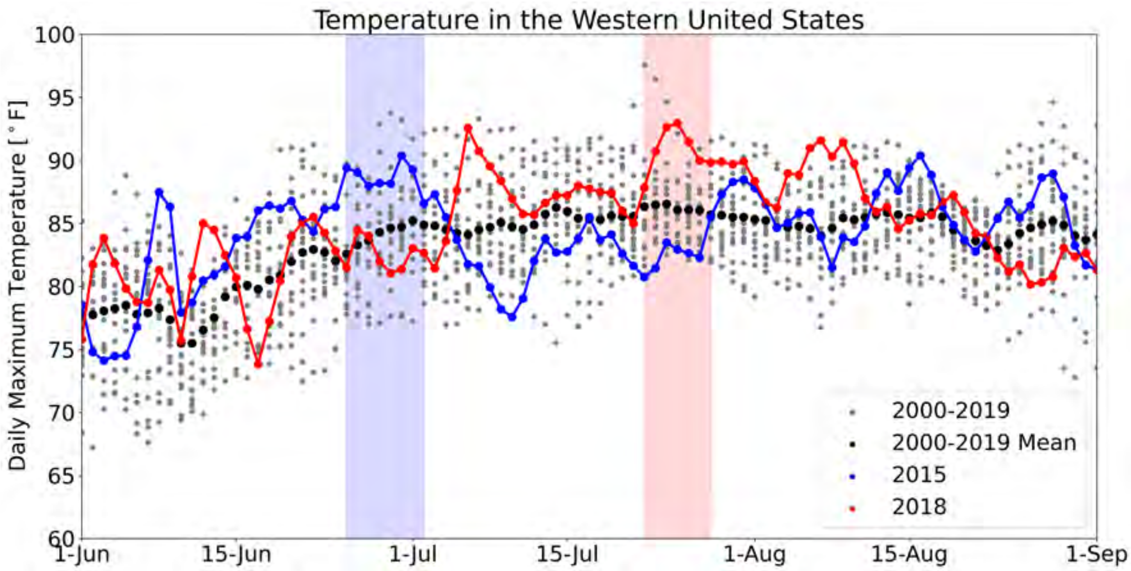
Schedule C	Energy generation loss (TWh)												
Generator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DCPP 1	–	–	–	–	–	–	–	–	–	–	–	–	–
DCPP 2	–	–	0.6	0.9	0.9	0.9	0.9		–	–	–	–	4.1
Columbia 2	–	–	–	–	–	–	–	–	–	–	–	–	–
Palo Verde 1	–	–	–	–	–	–	–	–	–	–	–	–	–
Palo Verde 2	–	–	–	–	–	–	–	–	–	0.9	1.0	1.0	2.8
Palo Verde 3	–	–		1.0	1.0	1.0	1.0	0.3	–	–	–	–	4.2
Total	–	–	0.6	1.8	1.9	1.8	1.9	0.3		0.9	1.0	1.0	11.1

Table 11. Nuclear energy generation loss monthly and total for Schedule D 2025.

Schedule D	Energy Generation Loss (TWh)												
Generator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DCPP 1	–	–	–	–	0.8	0.9	0.9	0.9	0.6	–	–	–	4.1
DCPP 2	–	–	–	–	–	–	–	–	–	–	–	–	–
Columbia 2	–	–	0.6	0.9	0.9	0.9	0.6	–	–	–	–	–	3.8
Palo Verde 1	–	–	–	–	–	–	–	–	–	–	–	–	–
Palo Verde 2	1.0	0.6	–	–	–	–	–	–	–	–	–	–	1.6
Palo Verde 3	–	–	–	–	–	–	–	–	–	–	–	–	
Total	1.0	0.6	0.6	0.9	1.7	1.7	1.5	0.9	0.6				9.5

4.4.1.2 Heat Wave Implications for WI

The previously introduced western U.S. heat wave events are leveraged to generate the heat wave system load events for the WI. By selecting heat waves of differing spatial extents, enables the analyses of the system behavior for geographically and intensity distinct scenarios providing incites of the transmission characteristics in mitigating power system stress across the system and regional impacts. Figure 25 depicts the evolution of daily maximum temperatures in the western U.S. from 1980 to 2019. The blue and red lines highlight the 2015 and 2018 heat wave events, respectively, with shading indicating their magnitude. During both events, daily maximum temperatures were 8–10°F above historical averages, with slightly warmer conditions observed in 2018. Notably, these events broke daily temperature records in multiple locations.



Sss

Figure 25. The progression of the daily maximum population-weighted temperature across the western U.S. from June to August is depicted. Each gray dot represents the daily maximum temperature in a sample year spanning from 1980 to 2019. The black dots denote the average maximum temperature observed during this period. The blue and red dots and lines illustrate the temperature trends in 2015 and 2018, respectively. Notably, the shaded blue and red boxes highlight the occurrences of the heat wave events in 2015 and 2018, respectively [24].

The resulting load changes to consider the 2015 heat wave and 2018 heat wave are illustrated in Figure 26 (WI system load), Figure 27 (Northwest WI region load), and Figure 28 (California WI region load). The figures compare the 2030 WI ADS load with respect to the 2015 heat wave and the 2018 heat wave utilizing the average day of the month. The average day of the month is computed by taking the average of every month's hour (i.e., hour 1 to hour 24). Thus, each month is comprised of 24 data points representing the average day by taking the average of each respective hour within all days of that month and then plotting them from January to December. Figure 26 presents the WI system load. The considered heat waves increase the load during the event. The total energy in the year is made to match altering the load behavior for the complete year.

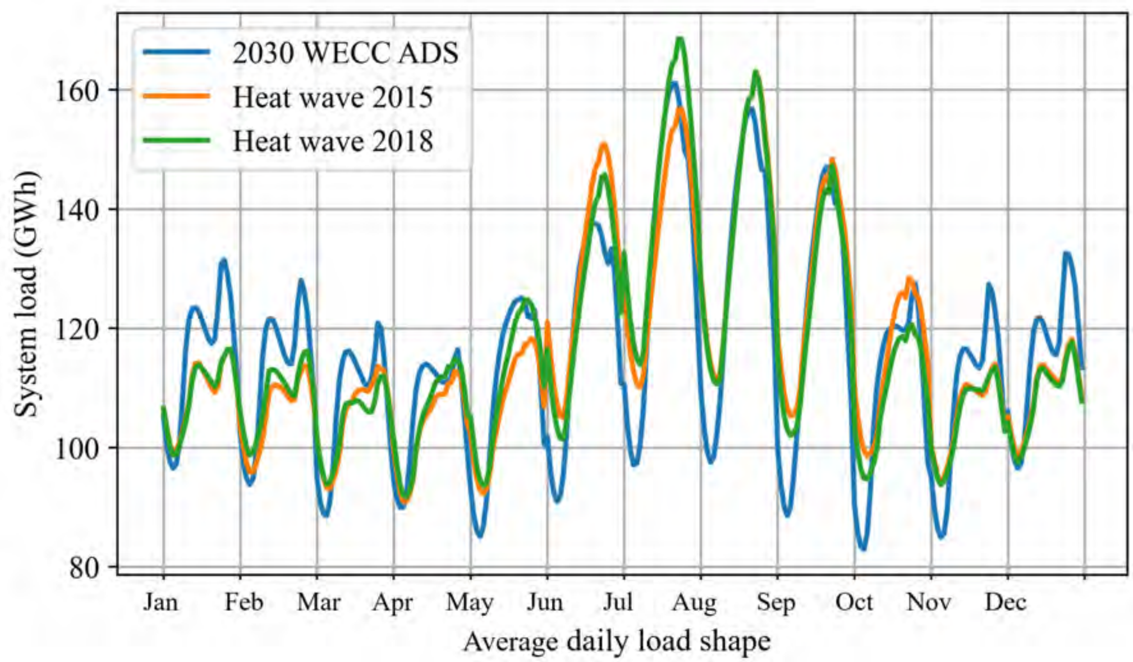


Figure 26. WI system total load for 2030 WI ADS model and alterations to consider the heat wave for the years 2015 and 2018.

Figure 27 illustrates the comparison of the 2030 WI ADS load with respect to the 2015 and 2018 heat waves in the NW region. The region is primarily impacted by the 2015 heat wave during the month of June, as demonstrated. Similarly, Figure 28 illustrates the loads for the CA region. The CA region is primarily impacted by the 2018 heat wave during the month of July, as presented.

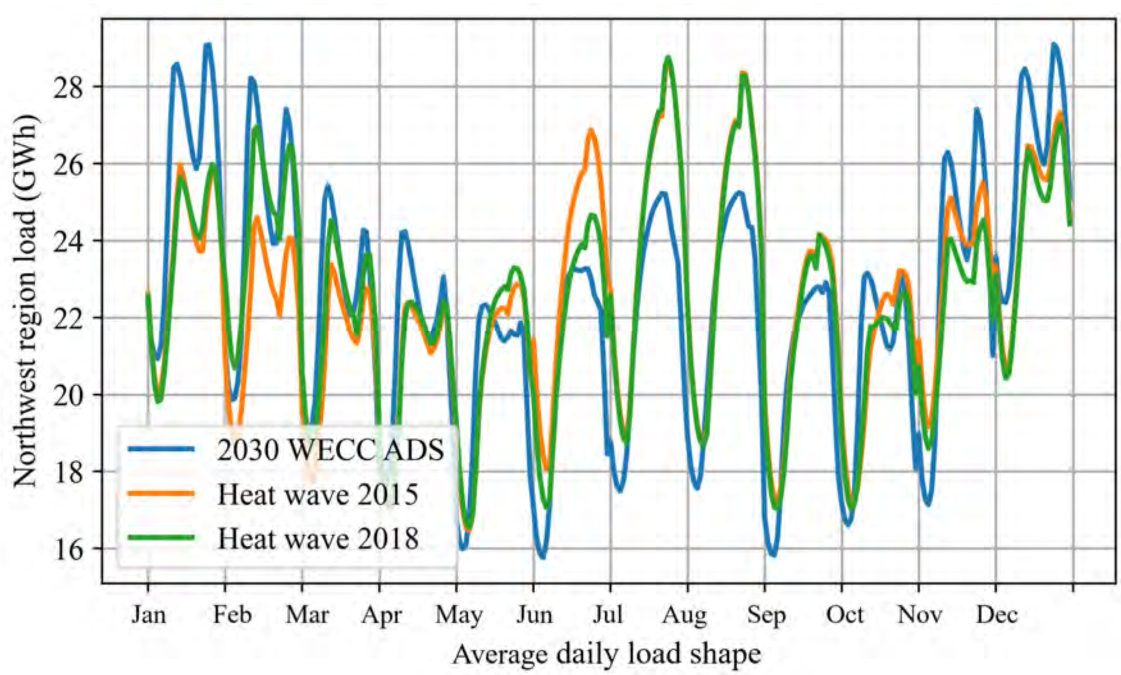


Figure 27. Northwest region total load for 2030 WI ADS model and alterations to consider the heat wave for the year 2015 and 2018. The average day of month for the month of June presents an increased peak for the heat wave 2015.

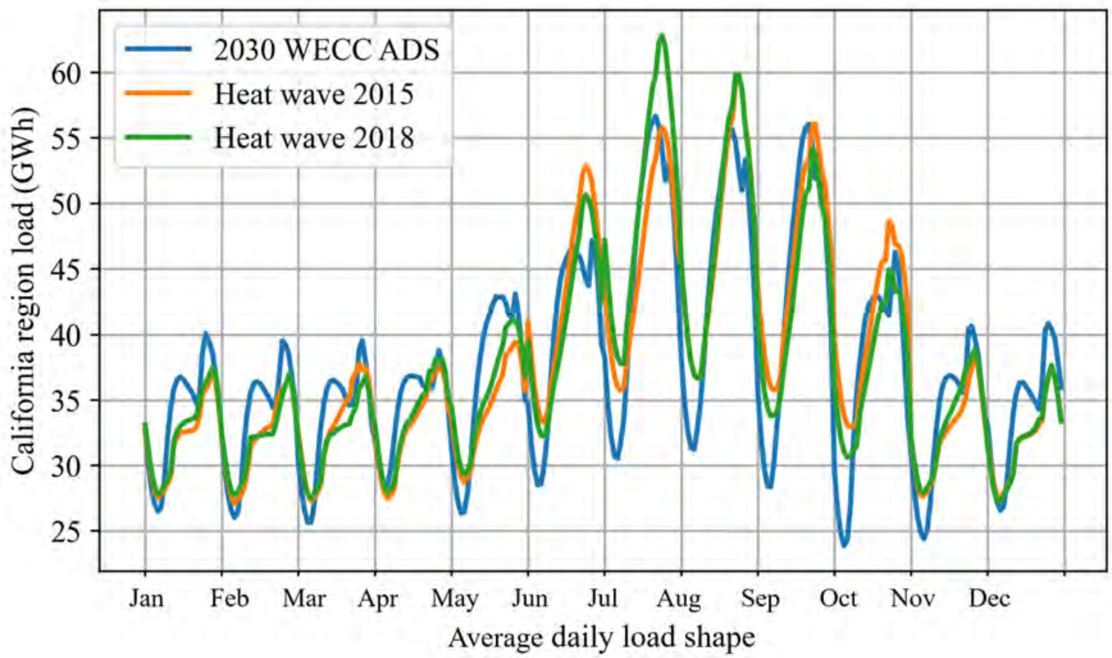


Figure 28. California region total load for 2030 WI ADS model and alterations to consider the heat wave for years 2015 and 2018. The average day of month for the month of July presents an increased peak for the heat wave 2018.

4.4.1.3 Drought Implications for WI

The previously introduced western U.S. 2001 drought year is leveraged to generate the hydro weekly dispatch for the WI system. For the purpose of matching the hydro dispatch in 2001, the simulation year is divided into 52 whole weeks, and each week has a weekly energy target amount that is individually simulated by GridView. Figure 29 illustrates the comparison from the 2030 WI ADS hydro weekly dispatch with respect to the 2001 drought for the whole WI system. Canadian hydropower plants were not included in this drought parameterization because of the absence of sufficient water inflow data needed to establish monthly energy targets and operating ranges.

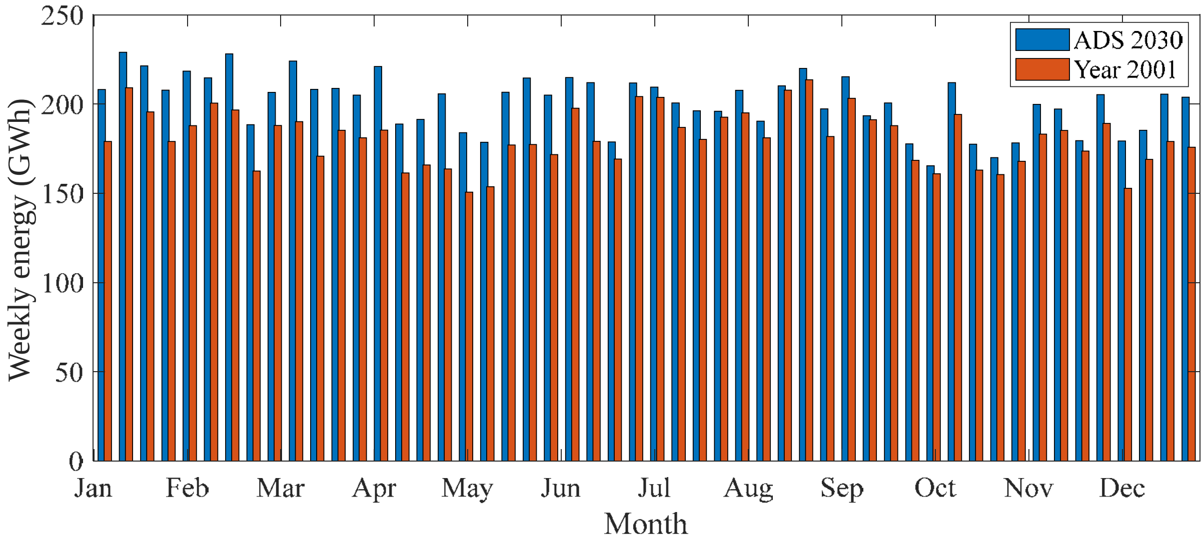


Figure 29. Weekly hydro dispatch (52 weeks) for 2030 WI ADS model and alterations to consider the drought for the year 2001. The weekly aggregation presents a reduction for hydro generation in year 2001, especially in spring season (about 20%).

4.4.1.4 Considered Scenarios for WI

We have conducted 24 experiments (six scenarios, and each scenario has four cases) to assess the impact of different threats on the WI system, as shown in Table 12. The six scenarios essentially differ by the weather conditions, such as drought and heat wave, and the four cases differ by the nuclear maintenance schedules being considered (as presented earlier being Schedule A, B, C, and D). Different cases in each scenario could be compared to evaluate the effect of nuclear maintenance schedules. The case name of the simulation follows the nomenclature of “S#&” having “S” for scenario, “#” for the scenario number, and “&” for the nuclear availability specification.

In Scenario 1 (S1), which is the benchmark of this study, the default profiles of the ADS 2030 is implemented to assess the impact of different nuclear maintenance schedules (i.e., S1A – S1D). In Scenario 2 (S2), the drought weather is considered, where the hydro dispatch parameters matching the drought year 2001 are updated in GridView simulations at a weekly time-step, assuming hydrologic conditions are known for each week. Comparing these experiments to Scenario 1 will measure the effectiveness of using weekly hydro dispatch parameters to guide PCM towards a more faithful representation of drought weather. Scenarios 3 (S3) and 4 (S4) update the load profiles generated from the TELL model to simulate the heat wave in 2015 and 2018, respectively. The difference between results from Scenarios 3 and 4 and Scenario 1 will estimate the effect of the heat wave on two major areas in the WI system (i.e., the NW and CA). Scenarios 5 (S5) and 6 (S6) further add drought dispatch to Scenarios 3 and 4.

Table 12. Considered scenarios for WI.

	Scenario	Nuclear Availability Status (Schedules)	Case Name	Load	Wind/Solar	Hydro
1	Extended Nuclear Maintenance Outage	A	S1A	2030 WI ADS	2030 WI ADS	–
		B	S1B			
		C	S1C			

	Scenario	Nuclear Availability Status (Schedules)	Case Name	Load	Wind/Solar	Hydro
		D	S1D			
2	Drought (2001 hydro weekly dispatch)	A	S2A	2030 WI ADS	2030 WI ADS	Derate Hydro PNNL 2001
		B	S2B			
		C	S2C			
		D	S2D			
3	Heat Wave 1 (2015 NW heat wave)	A	S3A	TELL model using 2015 weather profile	2030 WI ADS	–
		B	S3B			
		C	S3C			
		D	S3D			
4	Heat Wave 2 (2018 CA heat wave)	A	S4A	TELL model using 2018 weather profile	2030 WI ADS	–
		B	S4B			
		C	S4C			
		D	S4D			
5	Drought + Heat wave 1	A	S5A	TELL model using 2015 weather profile	2030 WI ADS	Derate Hydro PNNL 2001
		B	S5B			
		C	S5C			
		D	S5D			
6	Drought + Heat wave 2	A	S6A	TELL model using 2018 weather profile	2030 WI ADS	Derate Hydro PNNL 2001
		B	S6B			
		C	S6C			
		D	S6D			

4.4.2 Eastern Interconnection (EI)

4.4.2.1 Nuclear Maintenance Schedules EI

Different from WI region which only has limited number of BAs and nuclear plants, in PCM 2025, EI (excluding Canadian plants) has 86 unclear units and over 88 GW installed capacity. In the EI PCM, the fully unavailability of nuclear units (B) is not applicable. Thus, the considered nuclear availability status ranges only from total availability (A) to extended maintenance (C and D). The considered nuclear availability status are referred to the schedules A, C, and D, as shown in Table 13:

A. BAU maintenance schedule considering in year 2025. During this year, 25 units are scheduled in Spring, 26 units are in Fall, and 32 units are always available without maintenance schedules.

C. Extended maintenance schedule considering in year 2025. Extra 90 days maintenance schedule is added to 2025 BAU maintenance schedule.

D. Extended maintenance schedule considering in year 2026. During this year, 26 units are scheduled in Spring, 19 units are in Fall, and 38 units are always available without maintenance schedules. Extra 90 days maintenance schedule is added to 2026 BAU maintenance schedule.

It should be noted that the Vogtle Electric Generating Plant had two new units online in the last two years. Unit 3 began commercial operations on July 31, 2023, becoming the first new nuclear reactor in the United States in 7 years. And Unit 4 entered commercial operation on April 29, 2022. Since the historical expected maintenance is not available for these two new units, the future maintenance schedules are generated and leveraged to create the extend maintenance for nuclear availability status. It is noted that the Canadian plants are omitted for maintenance.

Table 13. Expected EI nuclear maintenance Schedule in 2025 (A and C) and 2026 (D) by region.

Nuclear Resources in EI			BAU Schedule in 2025			BAU Schedule in 2026		
Region in EI PCM	Count of units	Capacity (MW)	Units scheduled in Spring	Units scheduled in Fall	Units w/o schedule	Units scheduled in Spring	Units scheduled in Fall	Units w/o schedule
Florida	4	3,724	1	2	1	1	1	2
ISO-NE	3	3,527	0	2	1	1	0	2
MISO	14	13,236	3	3	8	5	3	6
NYISO	4	3,342	1	2	1	1	0	3
PJM	31	33,386	12	7	12	10	8	13
Southeast	27	28,844	8	9	10	8	6	13
SPP	2	2,135	1	1	0	0	1	1
Total	85	88,194	26	26	33	26	19	40

The temporal implications of the BAU 2025, 2026, and extended maintenance schedules C, D are presented from Table 14 to Table 16. Table 14 shows the BAU Schedule 2025 (A) maintenance, resulting in 44.7-TWh generation loss. As comparisons, Table 15 and Table 16 shows the energy loss for extended Schedule C and Schedule D, respectively. The energy generation loss is computed by multiplying the nameplate capacity by the number of hours the respective units are not available. The generation loss is almost 5 times compared with WI, considering EI is a larger system, although the maintenance schedules are expected to minimally affect available capacity. The maintenance and extended maintenance during months the EI region observe significant demand can place additional challenges in the system to supply the system demands and reserves. Besides, three major regions, i.e., MISO, PJM, and Southeast have different generation loss in these two extended maintenance schedules since most nuclear units' maintenance cycles are from 18 to 24 months. As a result, extended schedules C and D has about 80 and 95 TWh more nuclear generation loss compared with BAU schedules 2025 and 2026, respectively.

Table 14. Nuclear energy generation loss monthly and total for BAU Schedule 2025 (A).

Schedule A	Energy generation loss (TWh)												
Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Florida	0	0	0.4	0.5	0	0	0	0	0.1	0.8	0.1	0	1.8
ISO-NE	0	0	0	0.6	0.6	0	0	0	0	0	0	0	1.3
MISO	0	0.3	1.2	2.4	1.5	0	0	0	0	1.4	1.3	0.2	8.3

NYISO	0	0	0.1	0.3	0	0	0	0	0	0	0	0	0.4
PJM	0	0.7	2.3	4.9	2.2	0.2	0	0	0.7	4.1	2.2	0	17.3
Southeast	0	0.3	2.9	3.3	1.6	0.2	0	0	0.6	2.1	2.9	0.1	14.1
SPP	0	0	0	0	0	0	0	0	0.4	0.9	0.2	0	1.5
Total	0	1.3	6.9	12	5.9	0.4	0	0	1.8	9.3	6.7	0.3	44.7

Table 15. Nuclear energy generation loss monthly and total for extended Schedule 2025 (C).

Schedule F	Energy generation loss (TWh)												
Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Florida	0	0	0.4	0.6	0.6	0.6	0.5	0	0.1	0.8	0.7	0.8	5
ISO-NE	0	0	0	0.6	1	0.9	1	0.6	0	0	0	0	4.1
MISO	0	0.3	1.3	3.3	3.6	3.3	2.5	1.4	0	1.4	1.9	2	21
NYISO	0	0	0.1	0.5	0.5	0.5	0.3	0	0	0	0	0	1.8
PJM	0	0.7	3	6.9	8.2	7.2	6	2	0.8	4.9	6.1	6.4	52.2
Southeast	0	0.3	3.1	5.6	6.5	6.1	4.1	1.5	0.7	2.2	3.7	3.8	37.5
SPP	0	0	0	0	0	0	0	0	0.4	0.9	0.9	0.9	3.2
Total	0	1.3	7.9	17.5	20.4	18.6	14.4	5.5	2	10.2	13.3	13.9	124.8

Table 16. Nuclear energy generation loss monthly and total for extended Schedule D 2026 (D).

Schedule F	Energy generation loss (TWh)												
Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Florida	0	0.1	1	1.3	1.4	1.3	0.8	0	0	0.6	0.6	0.6	7.8
ISO-NE	0	0	0	1.4	1.7	1.6	1.7	0.5	0	0.7	0.9	1	9.5
MISO	0	0	2.3	3.2	3.3	3.2	3.2	0.4	0	2	2.6	2.7	23
NYISO	0	0	0.2	1.3	1.4	1.3	1.1	0	0.4	0.6	0.6	0.6	7.6
PJM	0	0.4	2.7	6.8	8.7	8	5.5	2.5	1	3.4	4.6	4.8	48.3
Southeast	0	0.6	3.4	5.4	8.1	7.4	5.1	3.2	1.3	3.1	5.3	5.6	48.4
SPP	0	0	0	0	0	0	0	0	0	0.7	0.6	0.7	1.9
Total	0	1.1	9.6	19.4	24.6	22.8	17.4	6.6	2.7	11.1	15.2	16	146.5

4.4.2.2 Heat Wave Implications for EI

The resulting load changes to consider the 2015 heat wave and 2018 heat wave are illustrated in Figure 30. The figures compare the 2025 EI PCM load with respect to the 2015 heat wave and the 2018 heat wave utilizing the average day of the month. The average day of the month is computed by taking the average of every month’s hour (i.e., hour 1 to hour 24). Thus, each month is comprised of 24 data points representing the average day by taking the average of each respective hour within all days of that month and then plotting them from January to December. Figure 30 presents the aggregated EI system load. The considered heat waves increase the load during the event. The total energy in the year is made to match altering the load behavior for the complete year.

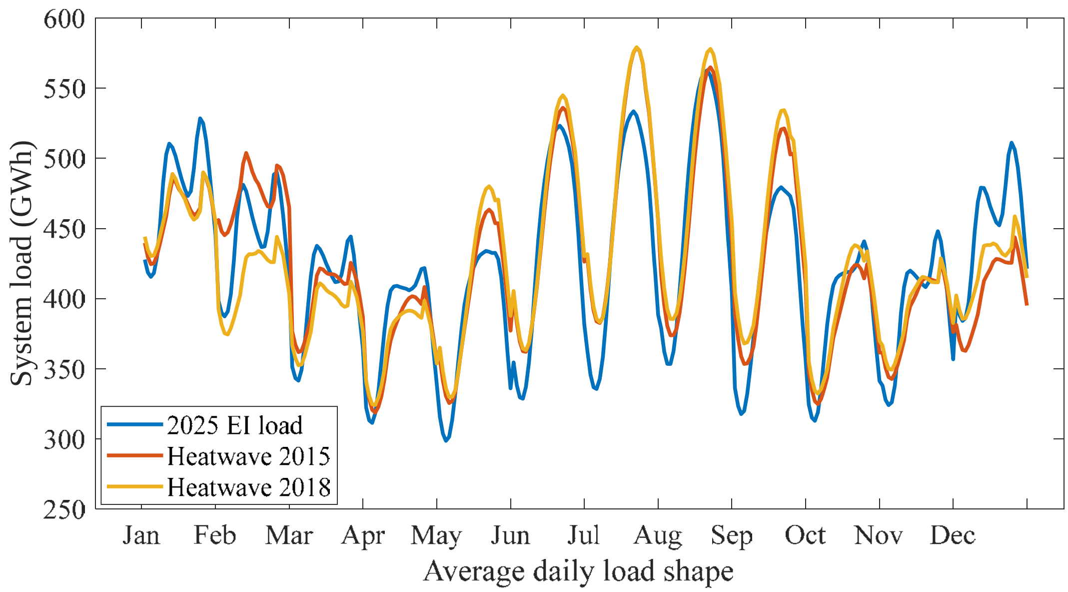


Figure 30. System total load for 2025 EI PCM model and alterations to consider the heat wave for the years 2015 and 2018.

4.4.2.3 Considered Scenarios for EI

We have conducted 9 experiments (three scenarios, and each scenario has three cases) to assess the impact of heatwave threats on the EI system, as shown in Table 17. The three scenarios essentially differ by the heatwave conditions, and the three cases differ by the nuclear maintenance schedules A, C, and D being considered (Schedule B – fully retirement of nuclear generation - is not applicable in EI). Different cases in each scenario could be compared to evaluate the effect of nuclear maintenance schedules.

In Scenario 7 (S7), which is the benchmark of this study, the default profiles of the EI 2025 PCM is implemented to assess the impact of different nuclear maintenance schedules in EI (i.e., S7A, S7C, and S7D). In Scenarios 8 (S8) and 9 (S9) update the load profiles generated from the TELL model to simulate the heat wave in 2015 and 2018, respectively. The difference between results from Scenarios 8 and 9 and Scenario 7 will estimate the effect of the two years of heat wave on the EI system.

Table 17 EI scenarios.

	Scenario	Nuclear Availability Status (Schedules)	Case Name	Load	Wind/Solar
7	Extended Nuclear Maintenance Outage	A	S7A	2025 EI	2025 EI PCM
		C	S7C		
		D	S7D		
8	Heat Wave 1 (2015 heat wave)	A	S8A	TELL model using 2015 weather profile	2025 EI PCM
		C	S8C		
		D	S8D		
9	Heat Wave 2 (2018 heat wave)	A	S9A	TELL model using 2018 weather profile	2025 EI PCM
		C	S9C		

	Scenario	Nuclear Availability Status (Schedules)	Case Name	Load	Wind/Solar
		D	S9D		

4.5 WI Results

The PCM considers regions outside the U.S. territory. The results presented exclude the load areas CFE (Comision Federal de Electricidad), BCHA (British Columbia Hydro Authority), AESO (Alberta Electric System Operator), IESO (Independent Electricity System Operator), and NPCC (Northeast Power Coordinating Council), resulting in the removal of regions in Canada and Mexico from the presented results. The electricity consumption in U.S. household is about 10.5 MWh per year [41]. The average U.S. household energy consumption is leveraged to estimate the number of homes affected by the nuclear availability. Alternatively, when the complete year is not considered the average household demand is proportionally diminished. The number of homes affected is included to assist the understanding of the implications the nuclear availability has for the people of the region. The unavailability of energy can have other implications.

4.5.1 Overview Characteristics of All Scenarios

4.5.1.1 Unmet Reserves

Reserves are instrumental in upholding grid stability, acting as a safeguard against abrupt shifts in demand and unforeseen interruptions in the power supply. As the integration of renewable energy sources expands, reserves become even more vital in harmonizing the intermittence of such generation with the dynamic demand. The GridView model encompasses various system reserves, with the simulations primarily influencing *regulation up* and *flexible up* reserves. These reserves impose specific requirements on the system to ensure it can accommodate additional generation with distinct ramping characteristics. *Regulation up* reserves, characterized by a ramping time of 10 minutes, and *flexible up* reserves, characterized by a ramping time of 20 minutes, play crucial roles in meeting dynamic demand fluctuations and operational needs within the grid. Both the *regulation up* and *flexible up* provide requirements to the system to be able of providing additional generation with different ramping characteristics. These reserve types contribute to system flexibility by enabling responsive adjustments in generation output, tailored to varying time scales of demand shifts and operational contingencies.

The unmet *regulation up* requirement for all the considered scenarios and nuclear availability Schedule A is presented in Table 18. The system cannot completely serve its reserves independent of the scenario under consideration. To assess the impact of nuclear availability on unmet *regulation up*, the unmet *regulation up* for each scenario is subtracted from the unmet *regulation up* for nuclear availability Schedule A. Thus, presenting the implications of nuclear availability on unmet *regulation up* in Table 19.

Table 18. Unmet *regulation up* by scenario for complete nuclear availability (Schedule A) by WI region. The unserved *regulation up* values are in GW computed by summing the unmet values for every hour.

Nuclear Availability	Region	Scenario					
		1	2	3	4	5	6
A	Basin	0.92	7.05	7.91	11.71	29.98	35.61
	California	0.02	0.71	0.29	0.67	3.79	9.01
	Northwest	3.77	12.69	5.62	6.77	23.91	25.42

Nuclear Availability	Region	Scenario					
		1	2	3	4	5	6
	Rocky Mtn	2.25	11.58	23.07	28.54	48.35	57.52
	Southwest	2.41	19.92	18.80	33.82	73.65	95.02
	Total	**9.36**	**51.96**	**55.68**	**81.51**	**179.70**	**222.57**

Table 19 presents the increased in unmet *regulation up* for to the different nuclear availability conditions. The unmet *regulation up* increases for the nuclear availability Schedule B, C, and D for all scenarios. The percentual increase is computed by dividing the increased total unmet *regulation up* by the corresponding total from nuclear availability Schedule A and converting the result into a percentage. The smallest percentual increase is from Scenario 1 nuclear availability Schedule C of 5 % and the maximum percentual increase is from Scenario 1 nuclear availability Schedule B of 355 %. The largest increase on unmet *regulation up* is Scenario 5 nuclear availability Schedule B of 212 GW.

Table 19. Unmet *regulation up* by scenario for nuclear availability Schedule B, C, and D by WI region. The unserved *regulation up* values are in GW computed by summing the unmet values for every hour. The values have been subtracted from the nuclear availability Schedule A to present the values dependent on the nuclear availability.

Nuclear Availability	Region	Scenario					
		1	2	3	4	5	6
B	Basin	4.65	15.30	18.47	18.01	35.49	30.89
	California	0.20	3.01	1.63	2.12	10.66	9.13
	Northwest	1.30	6.73	6.12	7.84	18.60	13.31
	Rocky Mtn	11.39	22.43	35.26	31.16	53.37	50.57
	Southwest	15.69	48.53	43.63	51.64	94.87	89.04
B	Total	33.24	96.00	105.11	110.78	212.98	192.94
	Increase	355%	185%	189%	136%	119%	87%
C	Basin	0.06	2.20	1.43	1.33	4.07	5.14
	California	0.03	0.11	0.12	0.33	1.31	1.88
	Northwest	0.03	0.50	0.23	1.10	2.10	2.91
	Rocky Mtn	0.53	5.31	4.90	6.40	11.88	10.33
	Southwest	-0.19	9.60	2.26	7.80	14.44	18.59
C	Total	0.45	17.71	8.95	16.95	33.79	38.85
	Increase	5%	34%	16%	21%	19%	17%
D	Basin	0.17	2.89	2.48	2.15	6.42	6.02
	California	0.03	0.13	0.21	0.30	1.27	1.50
	Northwest	0.04	0.74	0.77	1.62	2.60	2.68
	Rocky Mtn	0.62	4.34	2.95	4.07	8.72	8.13
	Southwest	0.35	8.13	3.89	7.38	12.80	15.65
D	Total	1.20	16.23	10.30	15.52	31.81	33.98
	Increase	13%	31%	18%	19%	18%	15%

The unmet *flexible up* requirement for all the considered scenarios and nuclear availability Schedule A is presented in Table 20. The system is not capable of completely serving its reserves independent of the scenario under consideration. To facilitate the implications of nuclear availability on unmet *flexible up* the unmet *flexible up* for each scenario is subtracted from the unmet *flexible up* for nuclear availability Schedule A. Thus, presenting the implications of nuclear availability on unmet *flexible up* in Table 21.

Table 20. Unmet *flexible up* by scenario for complete nuclear availability by WI region. The unserved *flexible up* values are in GW computed by summing the unmet values for every hour.

Avail.	Region	Scenario					
		1	2	3	4	5	6
A	Basin	6.63	50.52	64.62	80.94	196.60	238.31
	California	1.97	16.09	19.18	39.78	121.40	238.12
	Northwest	17.49	53.34	23.84	25.05	92.55	95.31
	Rocky Mtn	6.54	33.14	73.80	95.07	170.67	208.98
	Southwest	9.32	57.72	87.05	118.80	261.59	346.29
	Total	41.95	210.80	268.49	359.65	842.81	1,127.01

Table 21. Unmet *flexible up* by scenario for nuclear availability Schedule B, C, and D by WI region. The unserved *flexible up* values are in GW computed by summing the unmet values for every hour. The values have been subtracted from the nuclear availability Schedule A to present the values dependent on the nuclear availability.

Avail.	Region	Scenario					
		1	2	3	4	5	6
B	Basin	45.33	118.21	145.52	143.59	288.64	237.85
	California	13.27	94.78	140.52	141.72	350.22	290.56
	Northwest	5.87	27.88	30.07	32.17	87.57	64.07
	Rocky Mtn	34.28	87.93	123.92	124.60	195.81	173.96
	Southwest	71.88	202.01	258.46	252.30	490.92	401.19
B	**Total**	**170.64**	**530.80**	**698.50**	**694.37**	**1,413.16**	**1,167.63**
	Increase	**407%**	**252%**	**260%**	**193%**	**168%**	**104%**
C	Basin	1.43	16.25	7.00	17.87	32.07	36.63
	California	0.14	8.69	5.18	16.52	38.26	60.80
	Northwest	0.21	2.45	0.92	3.33	8.64	9.55
	Rocky Mtn	-0.42	17.85	16.24	23.95	40.28	24.26
	Southwest	0.60	26.87	13.23	33.47	60.36	65.49
C	**Total**	**1.95**	**72.10**	**42.58**	**95.13**	**179.62**	**196.73**
	Increase	**5%**	**34%**	**16%**	**26%**	**21%**	**17%**
D	Basin	1.44	17.08	14.98	22.77	39.71	35.96
	California	0.08	7.32	10.89	18.02	50.02	61.22
	Northwest	0.36	2.71	3.47	4.76	12.32	11.94

Avail.	Region	Scenario					
		1	2	3	4	5	6
	Rocky Mtn	0.79	13.18	10.63	19.27	30.51	25.90
	Southwest	2.14	20.81	24.20	35.46	58.21	56.72
D	**Total**	**4.81**	**61.11**	**64.17**	**100.27**	**190.77**	**191.74**
	Increase	**11%**	**29%**	**24%**	**28%**	**23%**	**17%**

Table 21 presents the increased in unmet *flexible up* for to the different nuclear availability conditions. The unmet *flexible up* increases for nuclear availability Schedule B, C, and D for all scenarios. The percentual increase is computed by dividing the increased total unmet *flexible up* by the corresponding total from nuclear availability Schedule A and converting to percentage. The smallest percentual increase is from Scenario 1 nuclear availability Schedule C of 5 % and the maximum percentual increase is from Scenario 1 nuclear availability Schedule B of 407 %. The largest increase on unmet *flexible up* is Scenario 5 nuclear availability Schedule B of 1,413 GW.

4.5.1.2 Unserved Load

The unserved load for all the considered scenarios and nuclear availability Schedule A is presented in Table 22. The system is capable of supplying its load under normal conditions Scenario 1. The scenarios considering drought, heat wave, and heat wave with drought are unable to supply its complete load. To facilitate the implications of nuclear availability on unserved load the unserved load for each scenario is subtracted from the unserved load for nuclear availability A. Thus, presenting the implications of nuclear availability on unserved load in Table 23. The estimation of number of homes is computed by dividing the total unserved load by 10.5, the yearly electricity consumption, for Table 22 and Table 23.

Table 22. Unserved load by scenario for complete nuclear availability by WI regions. The unserved load values are in MWh.

Avail.	Region	Scenario					
		1	2	3	4	5	6
A	Basin	–	–	–	5	1,045	7,577
	California	–	953	243	4,361	31,999	147,520
	Northwest	–	361	–	690	2,085	46,144
	Rocky Mtn	–	5	138	2,349	10,237	29,042
	Southwest	–	57	704	10,120	13,755	56,571
A	**Total**	–	**1,376**	**1,085**	**17,524**	**59,121**	**286,855**
	N. homes	–	**131**	**103**	**1,669**	**5,631**	**27,320**

Table 23 presents the increased unserved load given the nuclear availability Schedule B, C, and D. Considering Scenario 1 only the total Nuclear Unavailability (B) has unserved load. The Scenarios 3, 4, 5, and 6 present the increase in unserved load given the different nuclear availability. The unserved load Scenario 2 drought conditions for the nuclear availability Schedule C subtracted from nuclear availability Schedule A results in negative values Table 23. Interestingly, unserved load decreased even though nuclear availability was lower. The PCM is co-optimizing for serving the load, reserve requirements (i.e., ancillary services), minimizing the cost of generation, emissions, and other pertinent soft constraints. The difference in unserved load is -121 MWh, still the difference in unmet *regulation up* and *flexible up* is

17 GW and 72 GW, respectively, highlighting the increased challenges the system faces for nuclear availability Schedule C. The PCM optimizing extends beyond mere load management, encompassing intricate unit commitment and dispatch, while accommodating multiple parameters.

Table 23. Unserved load by scenario for nuclear availability Schedule B, C, and D by WI region. The unserved load values are in MWh. The values have been subtracted from the nuclear availability Schedule A to present the values dependent on the nuclear availability.

Avail.	Region	Scenario					
		1	2	3	4	5	6
B	Basin	4	607	2,226	4,429	11,993	32,281
	California	3,431	39,789	49,808	87,218	246,356	370,296
	Northwest	1,845	4,617	4,245	11,452	61,521	211,792
	Rocky Mtn	5	2,486	8,586	20,409	33,435	62,960
	Southwest	625	13,306	23,536	53,494	87,981	177,966
B	**Total**	**5,910**	**60,806**	**88,401**	**177,001**	**441,286**	**855,295**
	N. homes	**563**	**5,791**	**8,419**	**16,857**	**42,027**	**81,457**
C	Basin	–	–	–	388	1,200	4,368
	California	–	-121	-208	7,452	16,763	64,171
	Northwest	–	–	–	70	5,292	33,766
	Rocky Mtn	–	–	453	1,836	2,472	6,906
	Southwest	–	0	310	5,238	5,101	29,650
C	**Total**	–	**-121**	**555**	**14,985**	**30,827**	**138,861**
	N. homes	–	**-12**	**53**	**1,427**	**2,936**	**13,225**
D	Basin	–	–	–	336	1,454	2,852
	California	–	805	2	6,372	20,281	57,344
	Northwest	–	120	–	408	7,276	27,563
	Rocky Mtn	-	81	924	2,658	3,147	6,286
	Southwest	-	60	877	1,893	7,621	16,679
D	**Total**	**–**	**1,066**	**1,803**	**11,666**	**39,779**	**110,724**
	N. homes	**–**	**102**	**172**	**1,111**	**3,788**	**10,545**

The analyses in Table 22 and Table 23 considers the entire year. However, the system faces the biggest challenges during peak load periods, which typically occur in the summer months. In the WI, peak load occurs in summer, with July and August experiencing the most unserved load. The Table 22 and Table 23 are re-made to include only data from July and August, presented in Table 24 and Table 25, respectively. To estimate the number of homes affected by the unserved load during these peak months, we divide the total unserved load by 1.75. This value is derived from two assumption: first, the average home uses 10.5 MWh per year. Second, the demand is equally distributed across the months results in 0.875 MWh per month and 1.75 MWh for two months.

The consideration of the months of July and August reduces the total unserved load, while demonstrating the system's challenge during these 2 months with unserved load. Considering Scenario 6 nuclear availability Schedule B the unserved load given the absence of nuclear for the complete year is

855,295 MWh and when considering only the months of July and August is 855,101 MWh. The total amount is almost the same but looking at the expected number of households without power due to nuclear unavailability increases from 81,457 to 488,629.

Table 24. Considering only Months 7 and 8. Unserved load by scenario for complete nuclear availability by WI region. The unserved load values are in MWh.

Avail.	Region	Scenario					
		1	2	3	4	5	6
A	Basin	–	–	–	5	–	7,577
	California	–	953	243	4,361	14,685	147,520
	Northwest	–	361	–	690	928	46,144
	Rocky Mtn	–	5	138	2,349	4,875	29,042
	Southwest	–	57	704	10,120	6,902	56,571
A	**Total**	–	**1,376**	**1,085**	**17,524**	**27,390**	**286,855**
	N. homes	–	**786**	**620**	**10,014**	**15,651**	**163,917**

Table 25. Considering only Months 7 and 8. Unserved load by scenario for nuclear availability Schedule B, C, and D by WI region. The unserved load values are in MWh. The values have been subtracted from the nuclear availability Schedule A to present the values dependent on the nuclear availability.

Avail.	Region	Scenario					
		1	2	3	4	5	6
B	Basin	4	607	1,653	4,429	7,583	32,281
	California	1,685	31,728	42,478	87,218	172,204	370,102
	Northwest	1,216	3,534	3,548	11,452	29,206	211,792
	Rocky Mtn	5	2,486	7,551	20,409	25,978	62,960
	Southwest	621	13,306	20,664	53,494	65,610	177,966
B	**Total**	**3,530**	**51,662**	**75,894**	**177,001**	**300,581**	**855,101**
	N. homes	**2,017**	**29,521**	**43,368**	**101,143**	**171,761**	**488,629**
C	Basin	–	–	–	388	–	4,368
	California	–	-121	-208	7,452	7,038	64,171
	Northwest	–	–	–	70	1,020	33,766
	Rocky Mtn	–	–	453	1,836	652	6,906
	Southwest	–	0	310	5,238	1,546	29,650
C	**Total**	–	**-121**	**555**	**14,985**	**10,255**	**138,861**
	N. homes	–	**-69**	**317**	**8,563**	**5,860**	**79,349**
D	Basin	–	–	–	336	6	2,852
	California	–	805	2	6,372	11,107	57,344
	Northwest	–	120	–	408	2,065	27,563
	Rocky Mtn	–	81	924	2,658	1,278	6,286
	Southwest	–	60	877	1,893	4,165	16,679

Avail.	Region	Scenario					
		1	2	3	4	5	6
D	**Total**	–	**1,066**	**1,803**	**11,666**	**18,620**	**110,724**
	N. homes	–	**609**	**1,030**	**6,667**	**10,640**	**63,271**

4.5.1.3 Generation Mix and Emissions

The generation mix for all performed simulations for the complete year is presented in Figure 31. The detailed definition of each case is shown in Table 12. The drought Scenarios 2, 5, and 6 present as expected reduced hydro generation, which is mostly replaced by NG. It can be observed that with reduced nuclear availability (i.e., B, C, and D) the nuclear unit's energy is mainly replaced by NG. The curtailment of solar and wind generation slightly decreases when nuclear and hydro power availability is reduced.

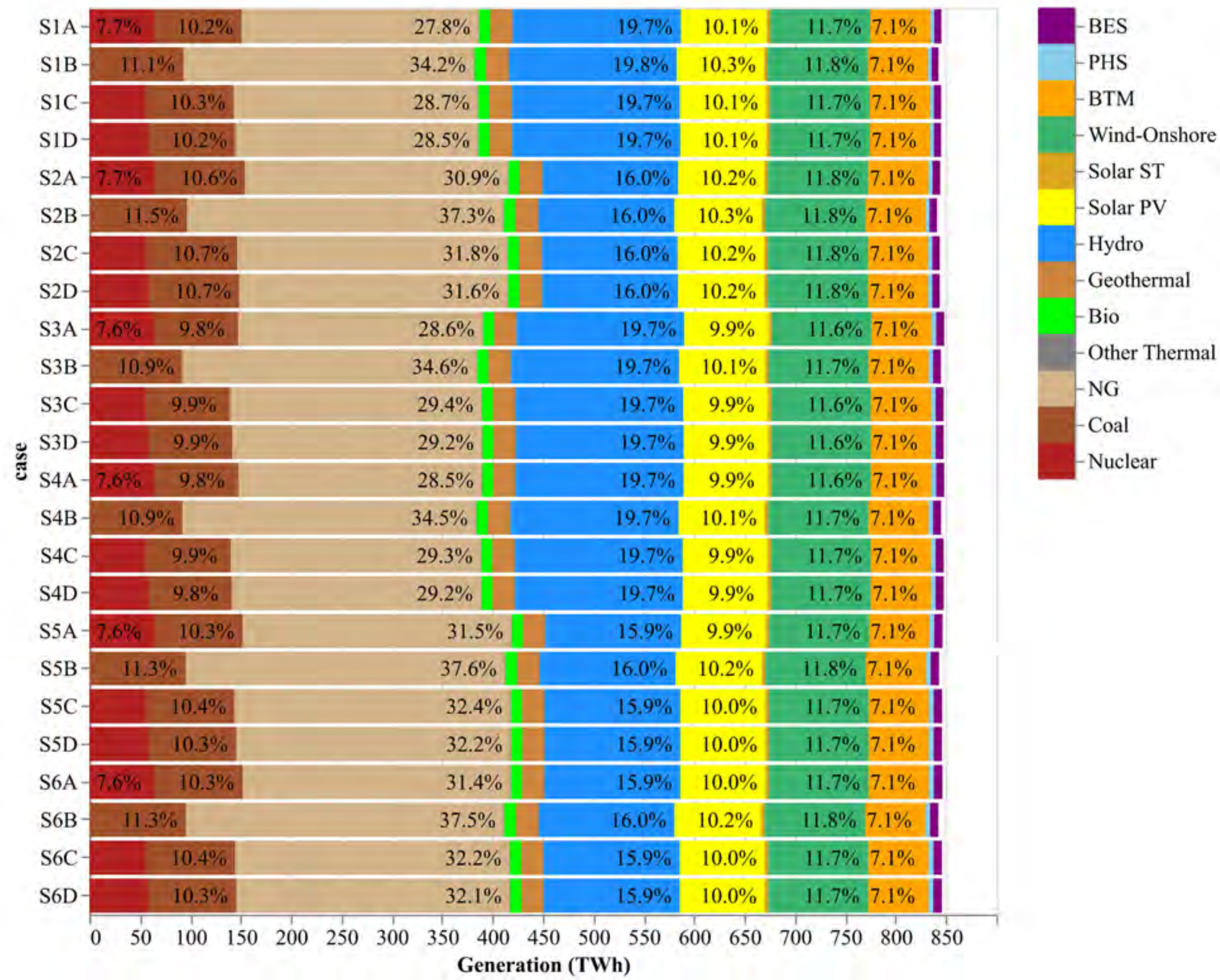


Figure 31. Generation mix for the complete year simulation in TWh. The Y-axis present the short name for all the simulations performed. The percentage values that do not appear are below the 7% threshold.

With the unavailability of nuclear units and hydro power the system becomes more reliant on NG units. A small increase in generation from coal units is also observed. Having increase of NG and coal units the emissions increase. Figure 32 presents the CO_2 emissions (in Tt) for all the simulations.

Similarly, the Figure 33 and Figure 34 present the emissions for NOx and SO_2. The presented emissions quantities consider the generation unit technology. Not all generation technologies produce emissions, so some units might be missing from the emissions visuals.

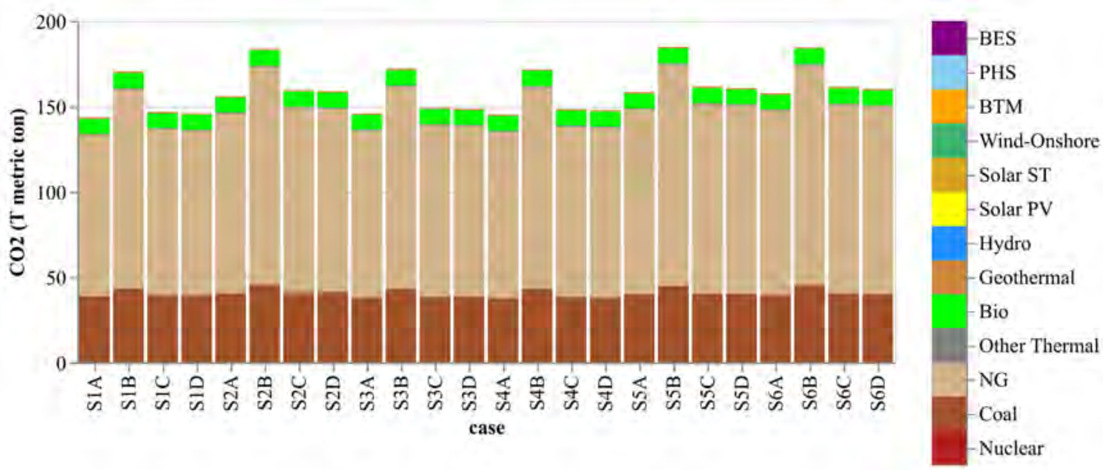


Figure 32. CO_2 for the complete year simulation in Tt (10^{12} metric ton). The X-axis presents the short name for all the simulations performed.

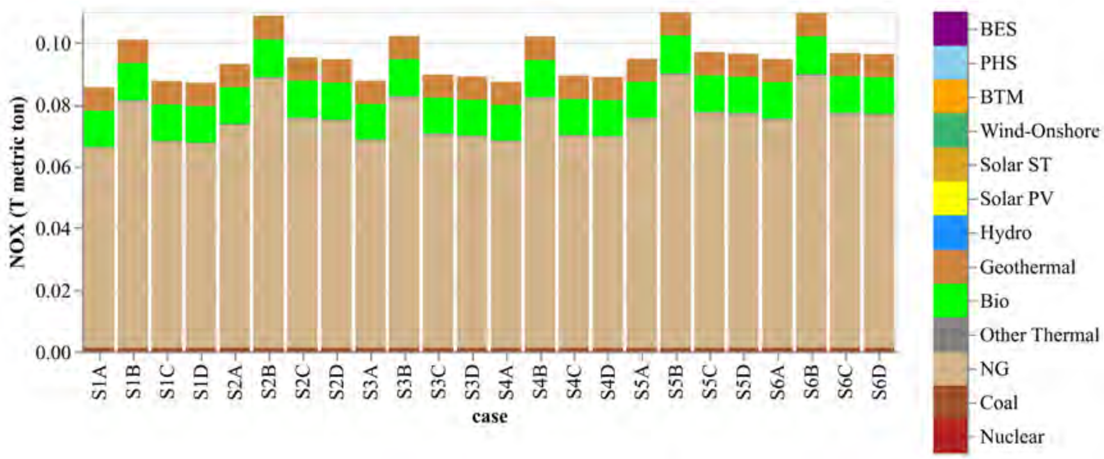


Figure 33. NOx for the complete year simulation in Tt (10^{12} metric ton). The X-axis present the short name for all the simulations performed.

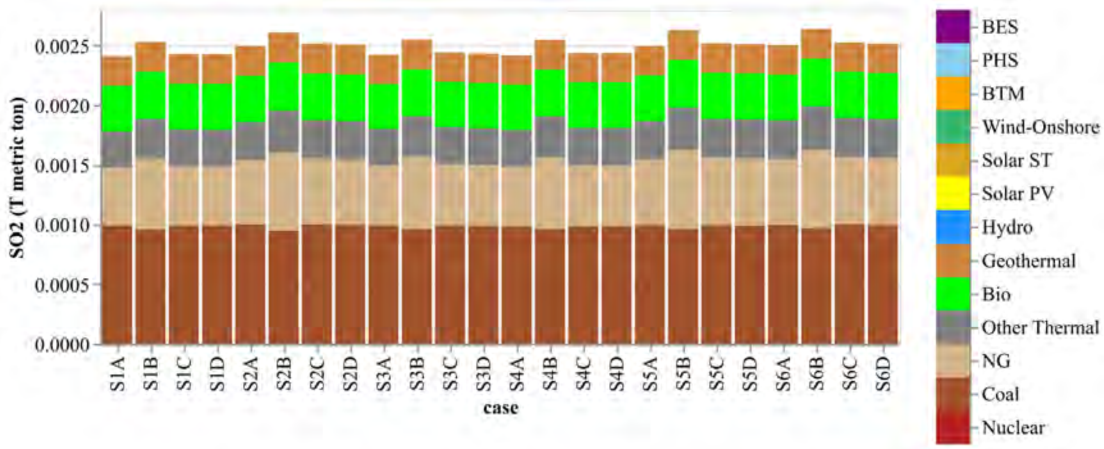


Figure 34. SO_2 for the complete year simulation in Tt (10^{12} metric ton). The X-axis present the short name for all the simulations performed.

4.5.2 Heat Wave 2015 Generation Mix Period from 2030-06-25 to 2030-07-02

The system demand aggregated for the year is the same for all simulations. The heat wave events alter the temporal demand as presented in Section 4.4.1.2. The 2015 heat wave effect is expected during the period from 2030-06-25 to 2030-07-02. Scenarios 3 and 5 include this 2015 heat wave load. Figure 35 presents the generation mix during the 2015 heat wave. The behavior matches the generation mix presented for the complete year in Section 4.5.1.3. Thus, nuclear, and hydro generation are mainly replaced by NG, resulting in increased emissions. The differences appear on the Scenarios 3, and 5 show larger demand and greater reliance on NG, leading to increased emissions during the period as well.

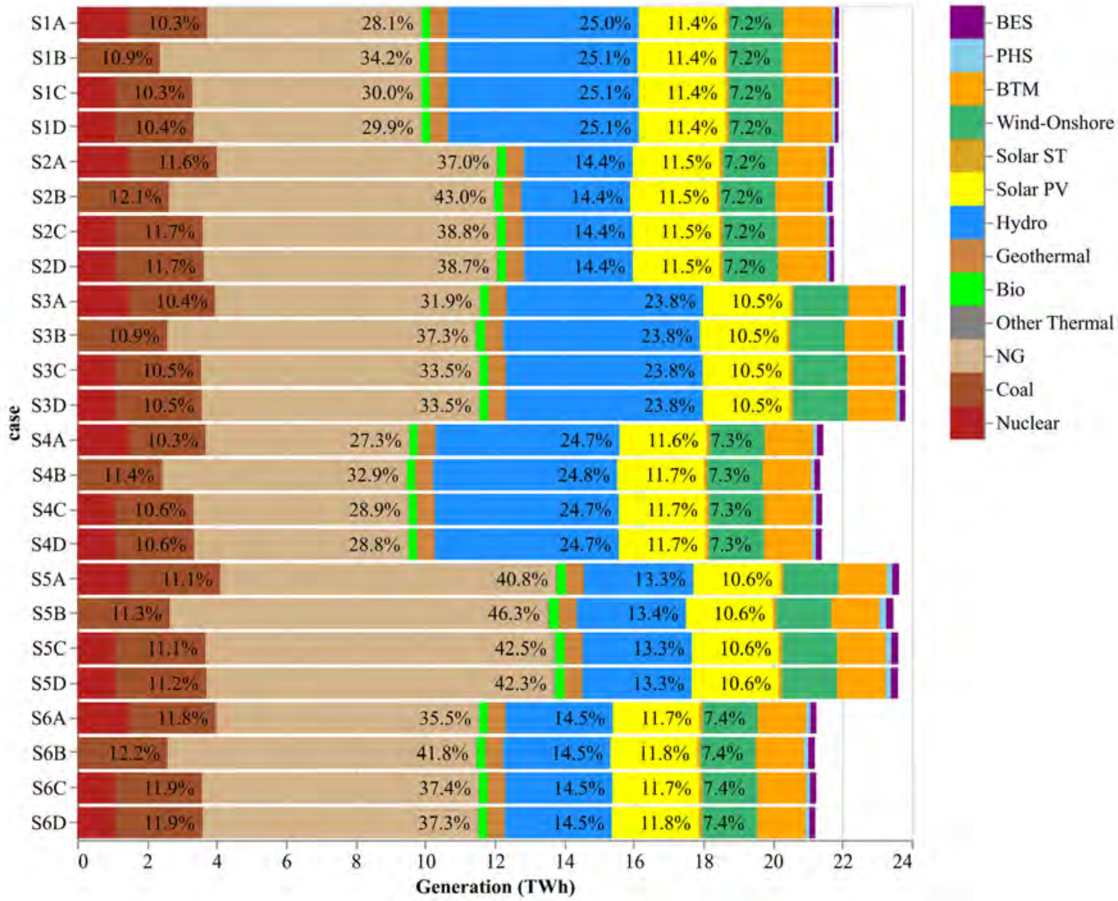


Figure 35. Generation mix for the 2015 heat wave period from 2030-06-25 to 2030-07-02 in TWh. The Y-axis present the short name for all the simulations performed. The percentage values that do not appear are below the 7% threshold.

4.5.3 Heat Wave 2018 Generation Mix Period from 2030-07-22 to 2030-07-28

The system demand aggregated for the year is the same for all simulations. The heat wave events alter the temporal demand as presented in Section 4.4.1.2. The 2018 heat wave effect is expected during the period from 2030-07-22 to 2030-07-28. The scenario with 2018 heat wave load is included in the Scenarios 4, and 6. Figure 35 presents the generation mix for the period of the 2018 heat wave. The behavior matches the generation mix presented for the complete year in Section 4.5.1.3. Thus, nuclear, and hydro generation are mainly replaced by NG having an increase in emissions. The differences appear on the Scenarios 4, and 6 exhibit a larger demand with a larger dependency in NG, resulting in increased emissions during the period as well.

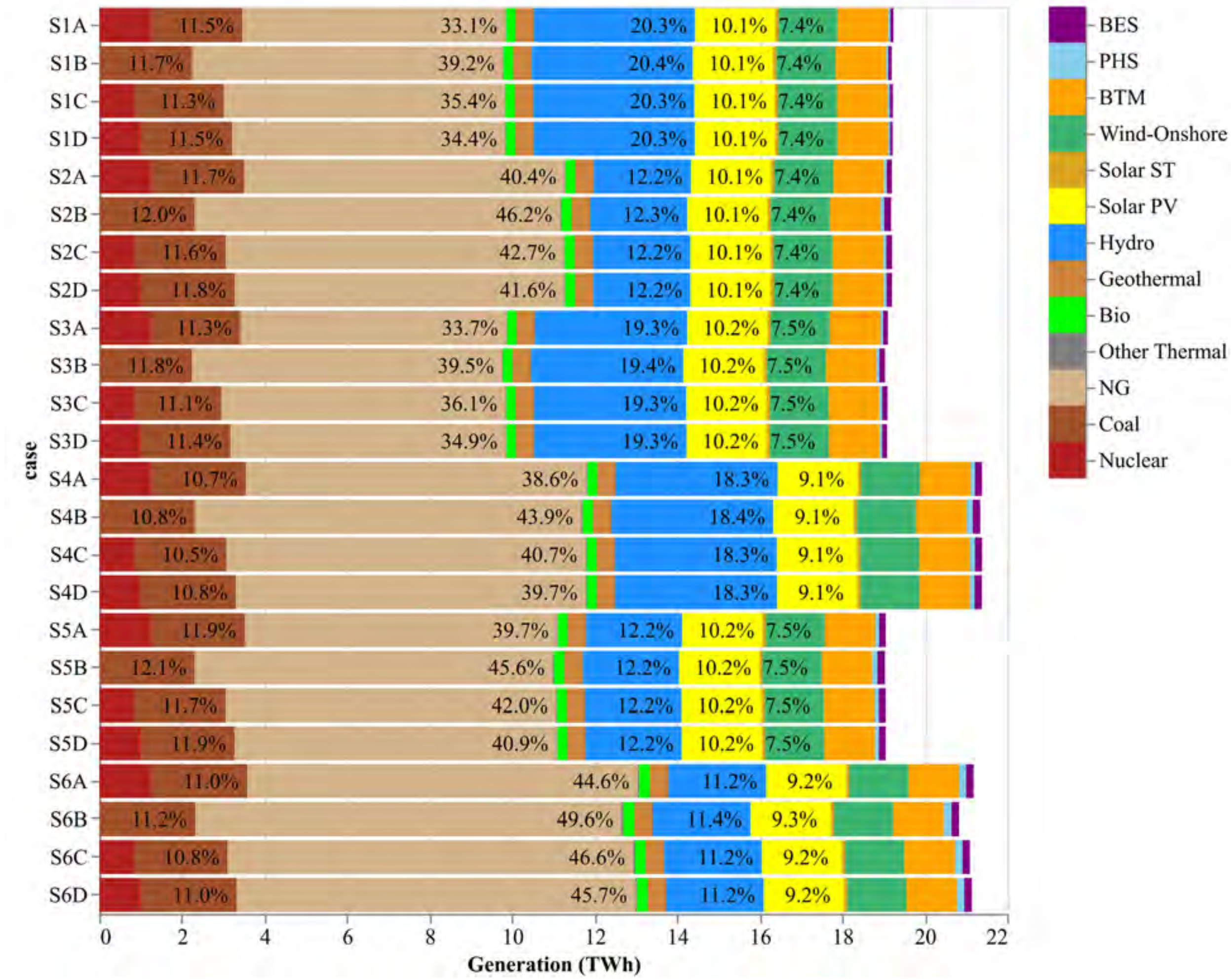


Figure 36. Generation mix for the 2018 heat wave period from 2030-07-22 to 2030-07-28 in TWh. The Y-axis present the short name for all the simulations performed. The percentage values that do not appear are below the 7% threshold.

4.5.4 Load Duration Curves

For the PCM PF, we use the annual load duration curves to show the 8760 hours of PF on different paths. The figure includes 8760 hours of PF sorted from the largest to lowest, maximum and minimum capacity and the utilization limits (U-limits) on the path. The utilization limits referred to as U75, U90, and U99 are the path utilization congestion metrics defined as the percentage of time the flow exceeds 75, 90, and 99 percent of the path operating transfer capacity. Five major paths are monitored, which are Path 65/66 (two major paths connecting NW with CA), Path 26 (Northern to Southern CA), Path 46 (DSW to CA), and Path 14 (Idaho to the NW). Two comparison groups are selected to show the impact of nuclear maintenance schedules, drought, and heat wave locations. The detailed definition of each case is shown in Table 12.

4.5.4.1 S1A, S1B, S1C, S1D – Impact of Different Nuclear Schedules

In this section, we choose four cases in Scenario 1 to show the impact of different nuclear schedules.

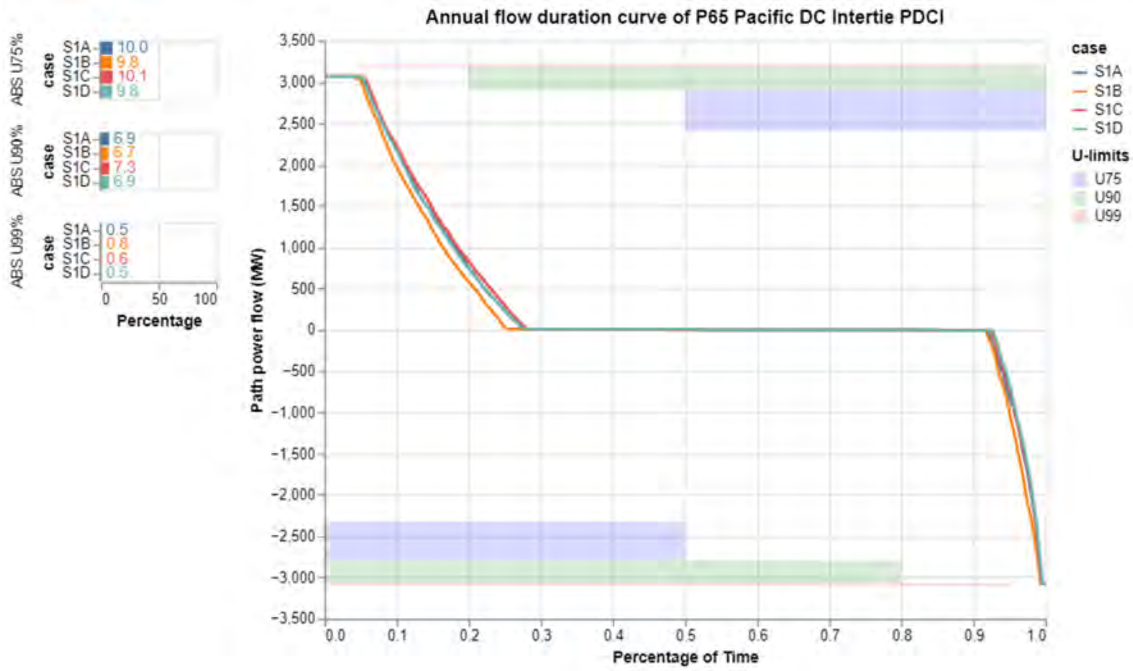


Figure 37. Annual flow duration curve of Path 65 (PDCI) to show the impact of different nuclear maintenance schedules. Less nuclear energy availability in CA (S1C) requires more energy import from NW, while Nuclear Unavailability (S1B) reduces energy import via PDCI.

As shown in Figure 37 on Path 65, there is an obvious reduction on bi-directional PF for Nuclear Unavailability (S1B), indicating loss of nuclear generation will reduce the energy flow on Path 65. Besides, there is a slight increase on the positive PF in S1C case compared with S1D case due to extended maintenance of Columbia Station in S1D.

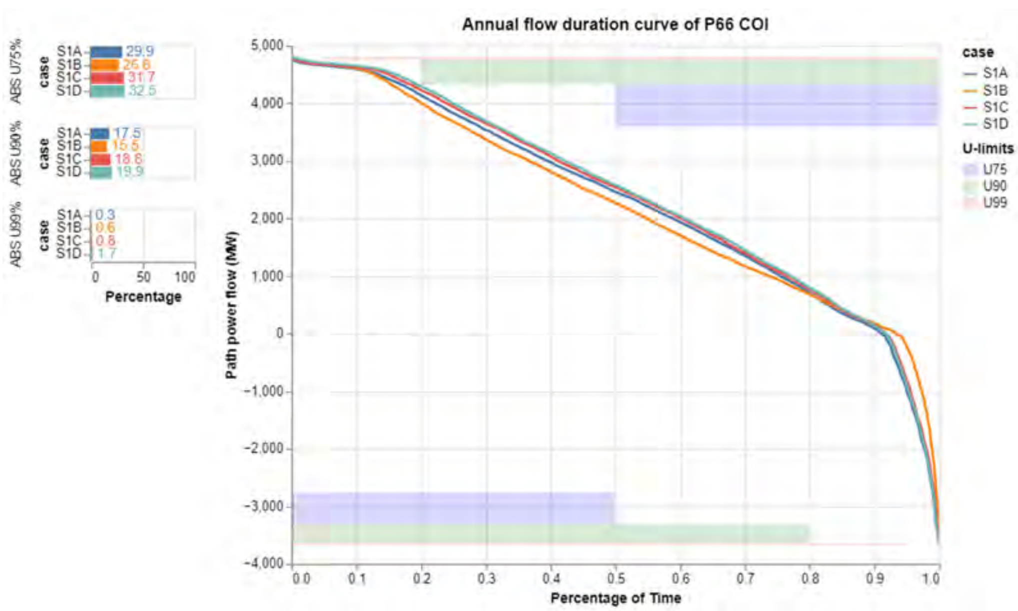


Figure 38. Annual flow duration curve of Path 66 (COI) to show the impact of different nuclear maintenance schedules. Less nuclear energy availability in CA and NW (S1C and S1D) increases the energy import from NW, while Nuclear Unavailability (S1B) reduces energy import via COI.

In Figure 38, Path 66 shows a reduction on positive PF and increase on negative for scenario without nuclear generation (i.e., S1B) compared with other cases, indicating loss of nuclear generation will reduce the energy flow from NW to CA while increase the reverse flow from CA to the NW. There is a slight decreased on the positive PF for extended maintenance cases (i.e., S1C and S1D) compared with base case (i.e., S1A).

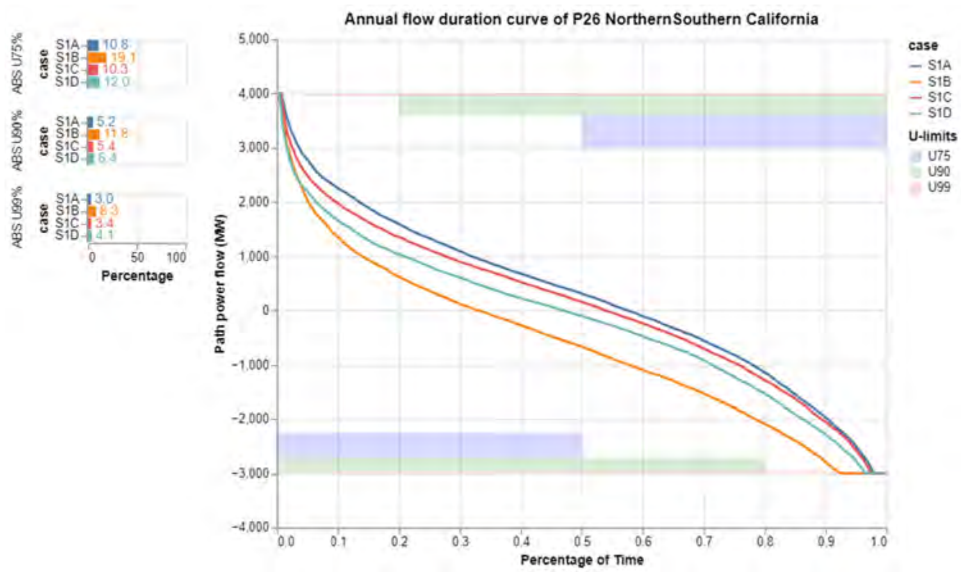


Figure 39. Annual flow duration curve of Path 26 (Northern-Southern CA) to show the impact of different nuclear maintenance schedules. Less nuclear energy availability (S1B, S1C, S1D) reduces the energy flow from Northern CA to Southern CA via Path 26.

In Figure 39, Path 26 shows a reduction on PF from Northern to Southern CA in both nuclear maintenance cases (S1B, S1C, S1D), indicating less nuclear availability will reduce the energy flow from Northern to Southern CA while increase the reverse flow from Southern to Northern CA. The results show the support from Southern CA to Northern CA to compensate the loss of nuclear generation.

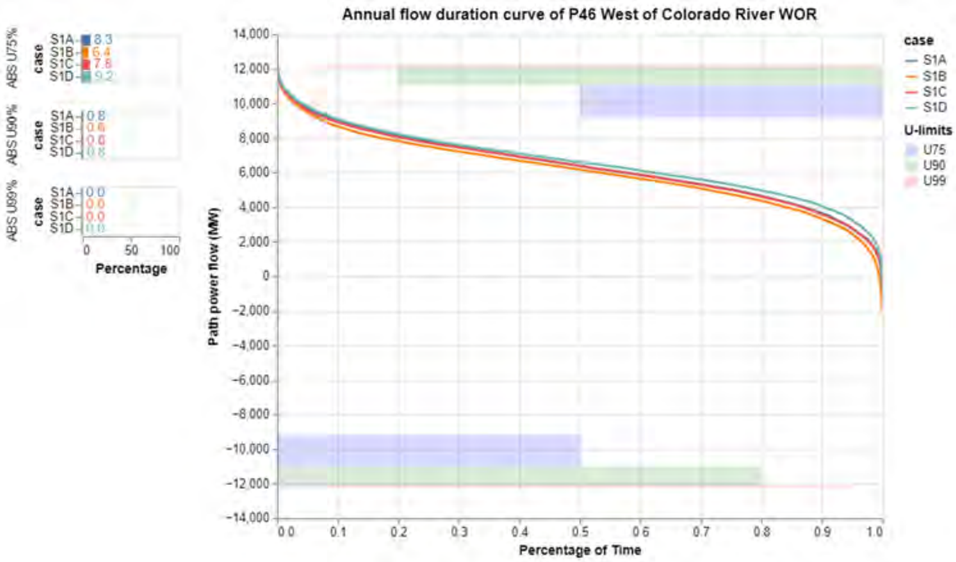


Figure 40. Annual flow duration curve of Path 46 (WOR) to show the impact of different nuclear maintenance schedules. Less nuclear energy availability (S1D) increases energy flow on Path 46, while Nuclear Unavailability (S1B) reduces energy flow on Path 46.

In Figure 40, there is a reduction on PF for Nuclear Unavailability (S1B), indicating Nuclear Unavailability (S1B) will reduce the energy flow from DSW to CA via Path 46. However, there is a slight increase on the positive PF in the S1D case compared with S1C due to the increased availability of nuclear power at the Palo Verde Station during extended maintenance D.

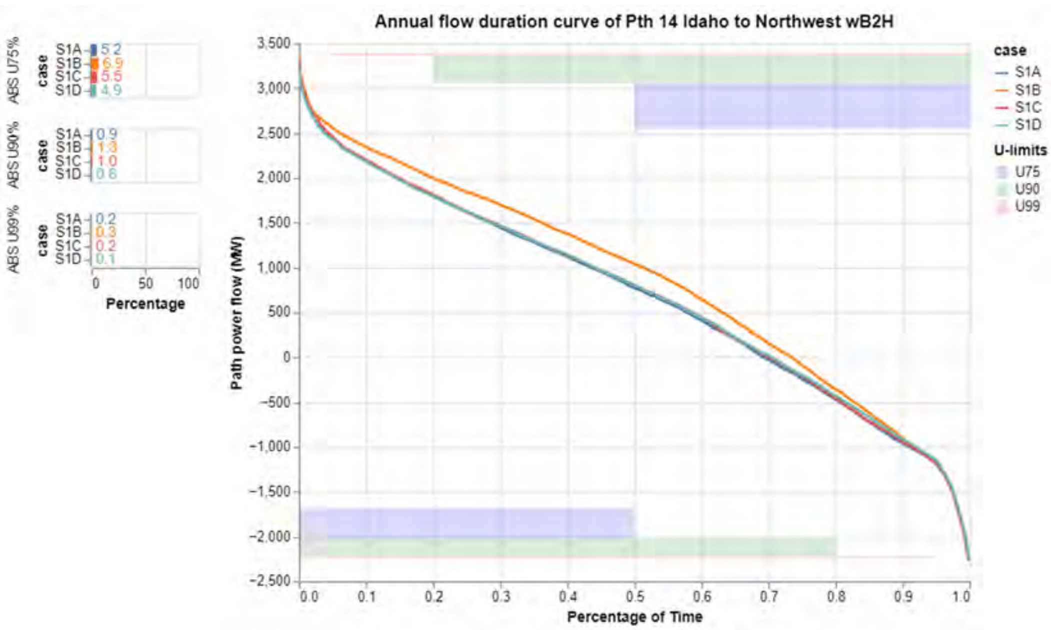


Figure 41. Annual flow duration curve of Path 14 (Idaho to the NW) to show the impact of different nuclear maintenance schedules. Nuclear Unavailability (S1B) requires more energy support from Idaho to the NW via Path 14.

In Figure 41, there is an obvious reduction on PF for Nuclear Unavailability (S1B), indicating that Nuclear Unavailability (S1B) will increase the energy flow on Path 14. This shows additional energy support from Idaho to the NW when nuclear energy is unavailable.

Key takeaways of different nuclear maintenance schedules are listed as follows:

- Decreasing nuclear energy availability requires more energy import from NW to CA via Path 65/66 (PDCI and COI).
- Decreasing nuclear energy availability reduces the energy flow from Northern CA to Southern CA via Path 26.
- Decreasing nuclear energy availability reduces energy flow from DSW to CA via Path 46, while nuclear maintenance Schedule D increases energy imports via Path 46. This is due to Palo Verde generating more power during Schedule D compared with Schedule C.
- Nuclear unavailability requires more energy support from Idaho to the NW via Path 14.

4.5.4.2 S1C, S2C, S5C. S6C – Impact of Drought + Heat wave under Nuclear Maintenance C

In this section, we chose four cases in different scenarios to show the impact of drought and heat waves under the same nuclear maintenance Schedule C, the detailed definition of each case is shown in Table 12.

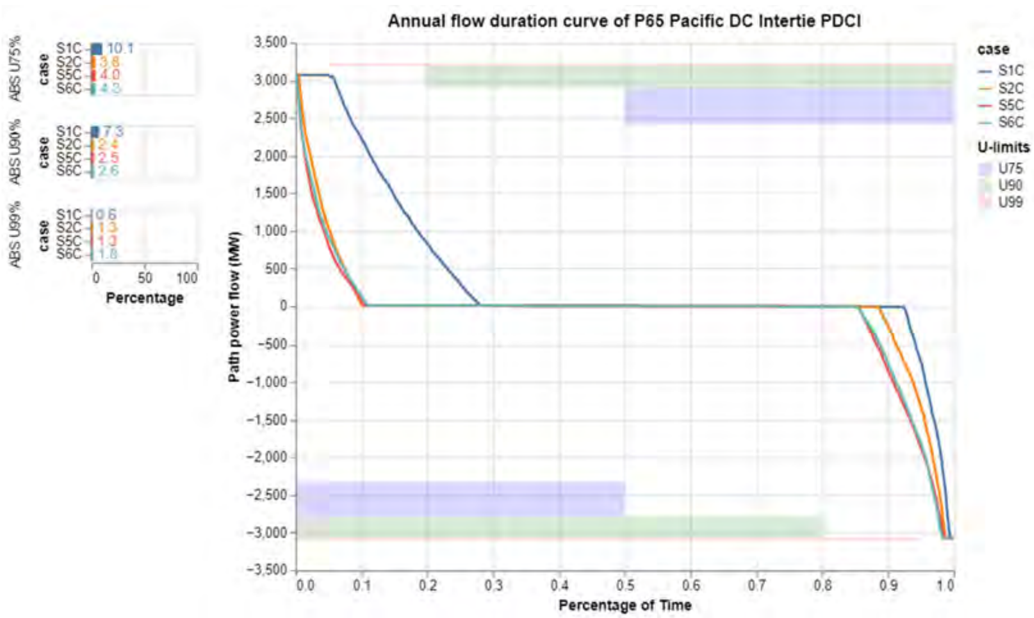


Figure 42. Annual flow duration curve of Path 65 (PDCI) to show the impact of drought and heat wave under nuclear maintenance Schedule C. Less hydropower availability (S2C, S5C, S6C) significantly reduces energy flow on Path 65 PDCI. Besides, NW heat wave (S5C) has less energy export to CA compared with CA heat wave (S6C).

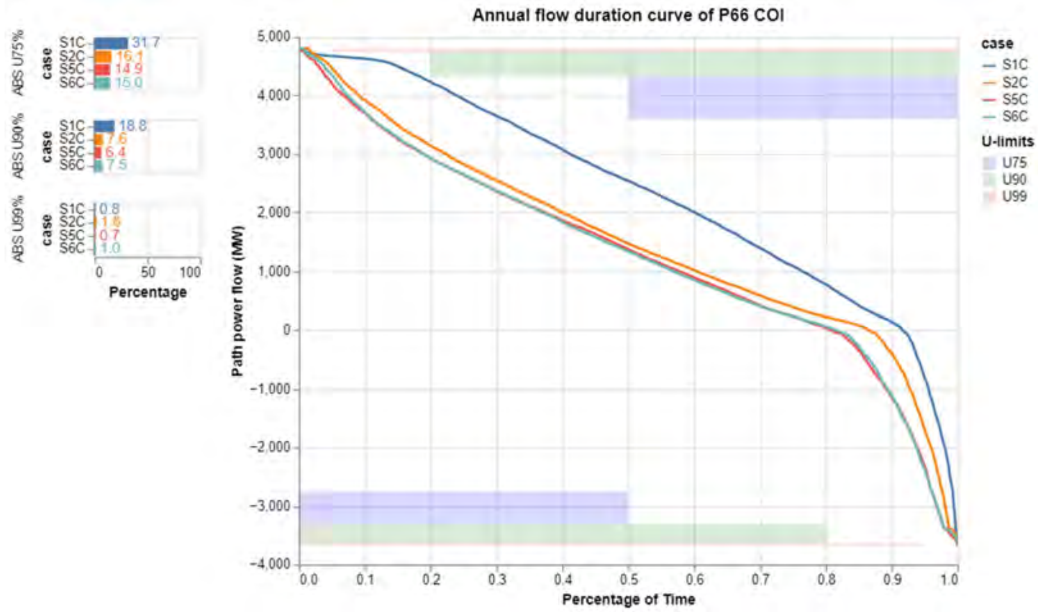


Figure 43. Annual flow duration curve of Path 66 (COI) to show the impact of drought and heat wave under nuclear maintenance Schedule C. The results show a similar pattern with Path 65 PDCI.

As shown in Figure 42 on Path 65 and Figure 43 on Path 66, there are significant reductions on both positive PFs for less hydropower availability in non-drought case (S1C) compared with other drought cases (S2C, S5C, S6C), indicating the hydropower is the major energy source to support CA from NW. Besides, there is a slight decrease on the positive power and increase in negative flow in S5C and S6C compared with S2C case due to heat wave in NW and CA. The results show that in combined heat wave and drought cases, more energy is required to support NW from CA.

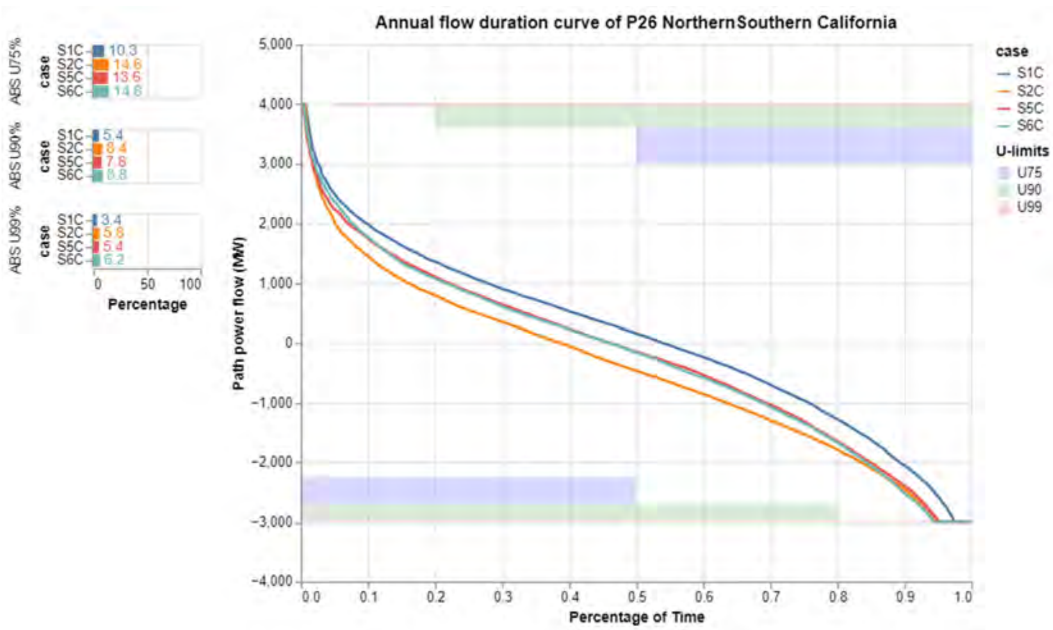


Figure 44. Annual flow duration curve of Path 26 (Northern-Southern CA) to show the impact of drought and heat wave under nuclear maintenance Schedule C. Less hydropower availability (S2C, S5C, S6C) and Nuclear Unavailability (S2C) reduces energy flow on Path 26.

In Figure 44, Path 26 shows a reduction on PF from Northern to Southern CA in both drought and heat wave cases (S2C, S5C, S6C), indicating less hydropower availability will reduce the energy flow from Northern to Southern CA while increase the reverse flow from Southern to Northern CA. Besides, S5C and S6C show a similar load duration pattern, indicating the location of heat wave (NW or CA) does not have an obvious impact on Path 26 inside CA.

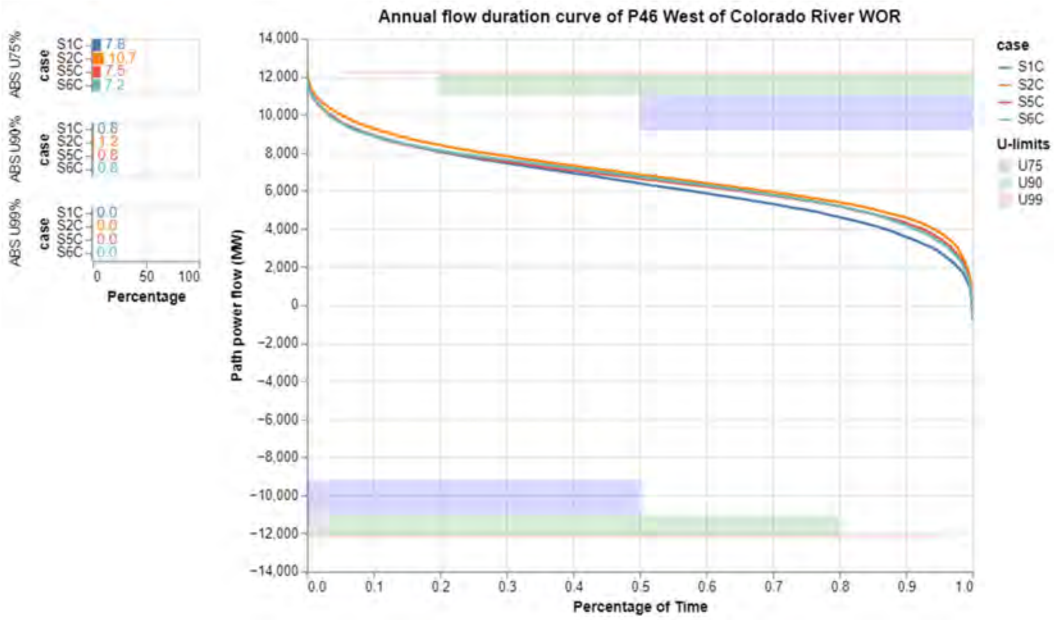


Figure 45. Annual flow duration curve of Path 46 (WOR) to show the impact of drought and heat wave under nuclear maintenance Schedule C. Drought and heat wave increase energy flow on Path 46.

In Figure 45, there is an increase on PF on Path 46 for all less hydropower availability cases (S2C, S5C, S6C), indicating DSW will support CA when drought occurs. However, there is a slight decrease on the positive PF in S5C and S6C cases compared with S2C, since DSW will require more energy to supply its own load during heat wave.

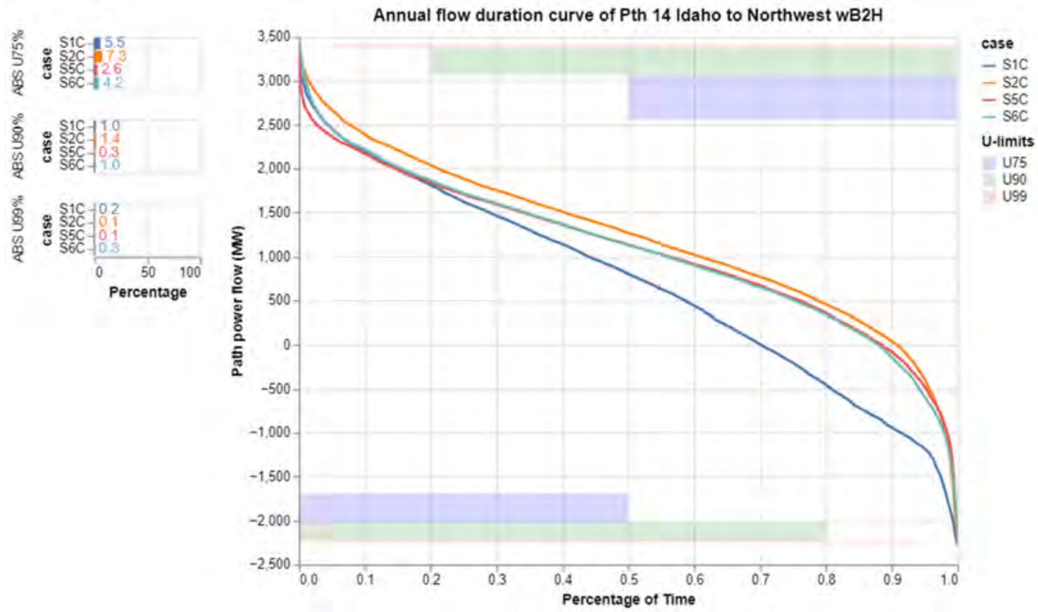


Figure 46. Annual flow duration curve of Path 14 (Idaho to the NW) to show the impact of drought and heat wave under nuclear maintenance Schedule C. Drought and heat wave requires more energy support from Idaho to the NW via Path 14.

In Figure 46, there is an obvious increase on PF in all drought cases (S2C, S5C, S6C), indicating Idaho will support more power to the NW when drought and heat wave occur.

The key takeaways of the impact of drought and heat wave are listed as follows:

- Less hydropower availability significantly affects energy flow from NW to CA via Path 65/66 (PDCI and COI). Besides, NW heat wave causes less energy export to CA compared with CA heat wave.
- Less hydropower and nuclear availability reduce energy flow on Path 26. The location of heat wave does not have an obvious impact on Path 26.
- Drought and heat wave require more energy support from DSW to CA via Path 46.
- Drought and heat wave require more energy support from Idaho to the NW via Path 14.

4.6 EI Results

4.6.1 Overview Characteristics of All Scenarios

4.6.1.1 Unmet Spinning Reserves

The unmet *spinning reserve* requirement for all the considered scenarios and nuclear availability are presented in Table 26. The system cannot completely serve its reserves for most of the scenario under consideration. The number of hours in which the reserves are not meet can decrease in relation to scenarios expected to be less strenuous for the system. For example, the S7A has hours of unmet spinning reserves for multiple regions will the heat have scenario S9A has no hours of unmet spinning reserves.

Table 26. Number of hours the unmet *spinning reserve* for all the scenario and nuclear availability by VSL. Presenting only the EI regions with at least 1 hour of any violation severity levels (VSL).

Nuclear Availability	Scenario	VSL	SPP	Southeast	Florida	Midcontinent ISO	PJM	Total
A	7	Lower	0	1	0	0	0	1
		Moderate	0	0	0	0	0	0
		High	1	0	0	0	0	1
		Severe	0	0	0	0	0	0
	8	Lower	0	0	0	0	0	0
		Moderate	0	0	0	0	0	0
		High	1	0	0	0	0	1
		Severe	0	0	0	0	0	0
	9	Lower	0	0	0	0	0	0
		Moderate	0	0	0	0	0	0
		High	0	0	0	0	0	0
		Severe	0	0	0	0	0	0
C	7	Lower	0	1	0	0	0	1
		Moderate	0	0	1	0	0	1
		High	0	0	1	0	0	1
		Severe	5	4	2	4	0	15
	8	Lower	0	0	0	1	0	1
		Moderate	0	1	1	0	0	2
		High	0	0	1	0	0	1
		Severe	5	4	2	4	0	15
	9	Lower	0	0	0	1	0	1
		Moderate	0	1	1	0	0	2
		High	0	0	1	0	0	1
		Severe	5	4	2	4	0	15
D	7	Lower	1	0	0	0	0	1
		Moderate	1	1	0	1	0	3
		High	0	2	0	0	0	2
		Severe	7	5	6	6	2	26
	8	Lower	1	0	0	0	0	1
		Moderate	1	1	0	0	0	2
		High	0	2	0	1	0	3
		Severe	7	5	6	6	2	26
	9	Lower	1	0	0	0	0	1
		Moderate	1	1	0	0	0	2
		High	0	2	0	1	0	3
		Severe	7	5	6	6	2	26

Table 26 presents the analyses performed directly keeping the information of the four VSL. Having the four VSL levels provided detail information of the type of hour being represented. However, it also makes it challenging to understand the overall behavior of the unmet spinning reserve. To facilitate the comparison Table 27 consolidate the different VSL levels of "Lower", "Moderate", "High", and "Severe" by considering the weight of 1, 2, 3, and 4 respectively. Demonstrating the nuclear availability has a larger implication on the number of hours with unmet spinning reserve than the heat wave scenarios.

Table 27. Number of hours the unmet *spinning reserve* for all the scenario and nuclear availability by VSL. Presenting only the EI regions with at least 1 hour of any VSL. The different VSL levels of "Lower", "Moderate", "High", and "Severe" are consolidated by considering the weight of 1, 2, 3, and 4 respectively.

Nuclear Availability	Scenario	SPP	Southeast	Florida	Midcontinent ISO	PJM	Total
A	7	3	1	0	0	0	4
	8	3	0	0	0	0	3
	9	0	0	0	0	0	0
C	7	20	17	13	16	0	66
	8	20	18	13	17	0	68
	9	20	18	13	17	0	68
D	7	31	28	24	26	8	117
	8	31	28	24	27	8	118
	9	31	28	24	27	8	118

4.6.1.2 Unserved Load

The unserved load for all the considered scenarios and nuclear availabilities is presented in Table 28. The system can supply its load under normal conditions Scenario 7 nuclear availability A. The Scenarios 8, and 9 considering heat wave are also able to supply the system load under the nuclear availability A and C. The portion of the analysis with unserved load are all related to the nuclear availability D. Only the hours “2025-06-25 18:00:00”, and “2025-06-25 19:00:00” for the nuclear availability D for all scenarios have unserved load. The nuclear availability D has the largest amount of nuclear unavailability for the month of June than all the other nuclear availability, as presented in Section 4.4.2.1. The heat wave scenario increases slightly the amount of unserved load.

Table 28. Unserved load by scenario for different nuclear availability by EI regions. The unserved load values are in MWh.

	Nuclear Availability	A			C			D		
	Scenario	7	8	9	7	8	9	7	8	9
Region	Florida	-	-	-	-	-	-	537	537	537
	ISO-NE	-	-	-	-	-	-	-	-	-
	MAPP (Non-MISO)	-	-	-	-	-	-	446	434	447
	MISO	-	-	-	-	-	-	53	202	168
	NYISO	-	-	-	-	-	-	-	-	-
	PJM	-	-	-	-	-	-	-	-	-
	SPP	-	-	-	-	-	-	34	42	36
	Southeast	-	-	-	-	-	-	-	-	-
Syste	**Total**	-	-	-	-	-	-	1,069	1,215	1,188

	N. homes year	-	-	-	-	-	-	102	116	113
	N. homes month	-	-	-	-	-	-	1,221	1,388	1,358

To estimate the number of homes affected by the unserved load during the year and the month of July, we divide the total unserved load by 10.5, and 0.875. This value is derived from two assumption: first, the average home uses 10.5 MWh per year. Second, the demand is equally distributed across the months results in 0.875 MWh per month.

4.6.1.3 Generation Mix and Emissions

The generation mix for all performed simulations for the complete year is presented in Figure 47. The detailed definition of each case is shown in Table 17. The extended nuclear maintenance Scenarios C and D present as expected reduced nuclear generation, which is mostly replaced by thermal units, resulting in increased emissions as shown in Figure 48. It can be observed that with reduced nuclear availability (i.e., C and D) the nuclear unit's energy is mainly replaced by NG. The solar and wind generation remain the same despite the nuclear generation and load demand are changed.

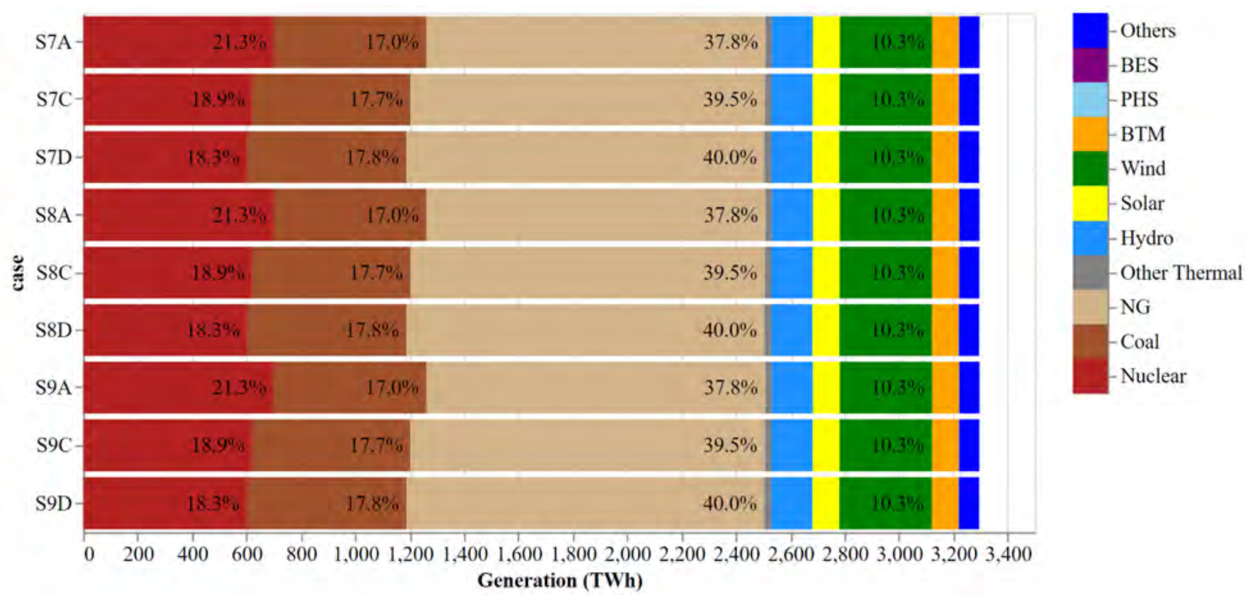


Figure 47. Generation mix for the complete year simulation in TWh. The Y-axis present the short name for all the simulations performed.

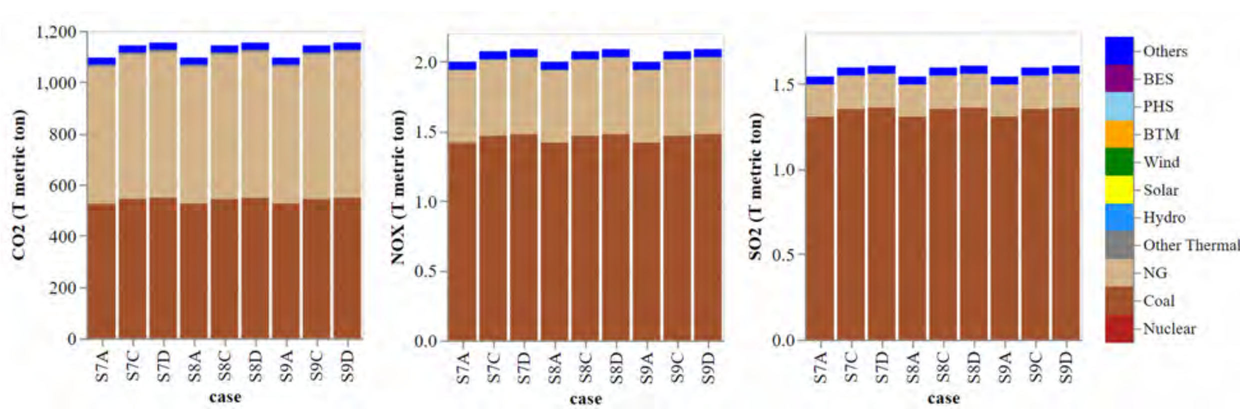


Figure 48. CO_2, NO_X, and SO_2 Emissions for the complete year simulation in Tt (10^{12} metric ton). The X-axis presents the short name for all the simulations performed.

4.6.2 Heat Wave Generation Mix Period from 2025-06-25 to 2025-07-02

The EI heat wave events alter the temporal demand as presented in Section 4.4.2.2. The heat wave effects are expected during the period from 2025-06-25 to 2025-07-02. Figure 49 presents the generation mix of EI system during the 2015 and 2018 heat waves. The behavior matches the generation mix presented for the complete year in Figure 47. Due to extended maintenance schedule, there are less nuclear generation in Scenarios C and D, compared with the whole year simulation in Figure 47. Thus, nuclear generation are mainly replaced by coal, NG units, and other types of thermal units, resulting in increased emissions.

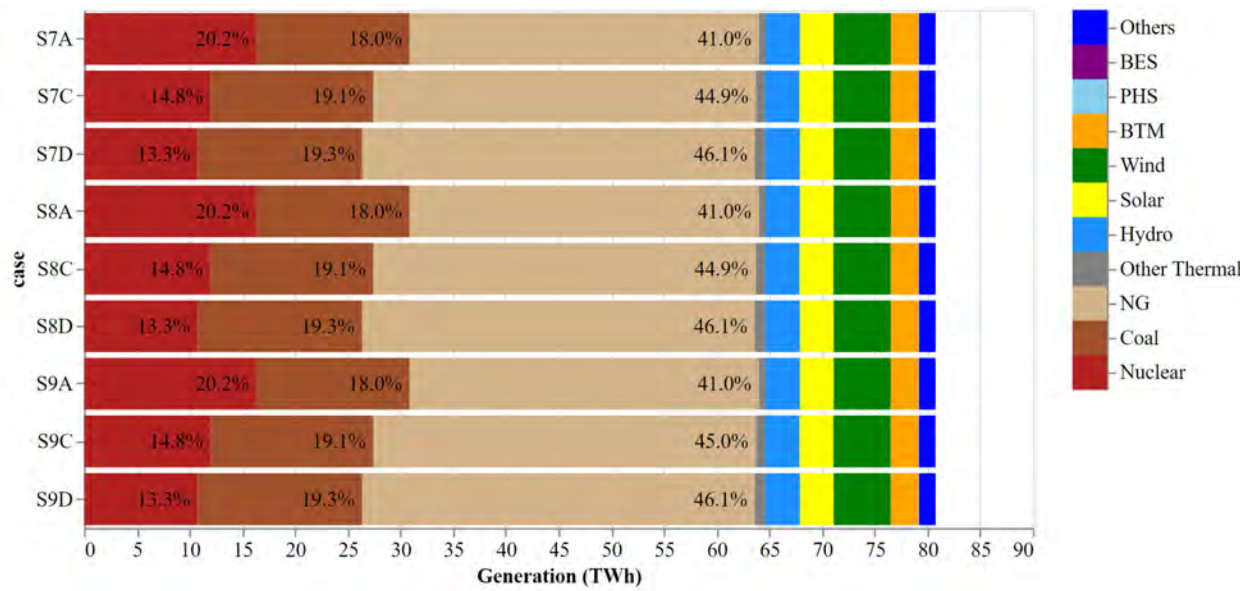


Figure 49. Generation mix for the EI system from 2025-06-25 to 2025-07-02 in TWh. The Y-axis present the short name for all the simulations performed, S8 and S9 refer to the heat wave cases.

Considering EI is a considerably larger system compared with WI, rather than monitoring load duration curves of several major paths in WI, we only focus on region-level energy generation in EI. Based on Table 13, nuclear resources in EI mainly are located in three major regions (i.e., Southeast, Midcontinent ISO, and PJM). Figure 50, Figure 51, and Figure 52 present the generation mix of three major regions in EI during the 2015 and 2018 heat waves, respectively. Due to extended nuclear maintenance schedule, these three regions both have considerable nuclear reduction during the heatwave event. To compensate the nuclear reduction, those areas must turn on more thermal units. However, based on the total generation mix, slight differences are observed:

.

- In Figure 50 and Figure 51, the total generation of Southeast and PJM region decreases in Scenarios C and D, indicating extra energy import needed from other regions during extended maintenance event
- In Figure 52, the total generation of Midcontinent ISO region increases in Scenarios C and D, indicating additional energy export to other regions during extended maintenance events.

- Other several regions, i.e., SPP, Florida, ISO-NE, and NYISO (SPP's generation mix is shown in Figure 53, other regions are omitted) increase thermal generation to support other regions during extended maintenance event.

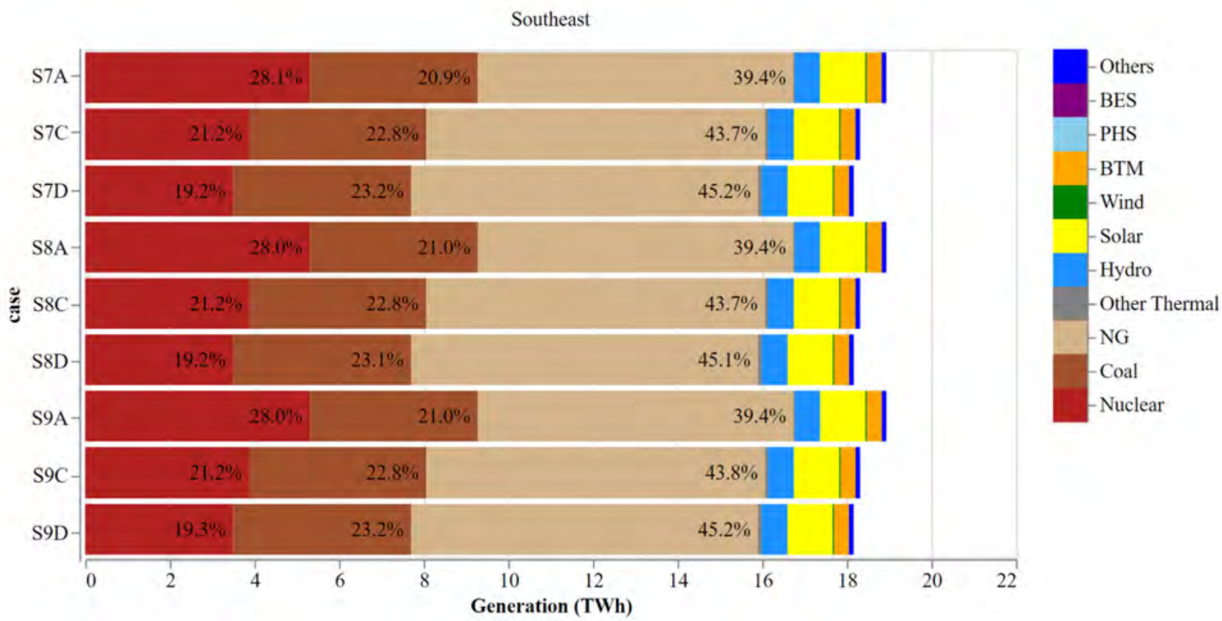


Figure 50. Generation mix for the Southeast region from 2025-06-25 to 2025-07-02 in TWh. The Y-axis present the short name for all the simulations performed, S8 and S9 refer to the six heat wave cases.

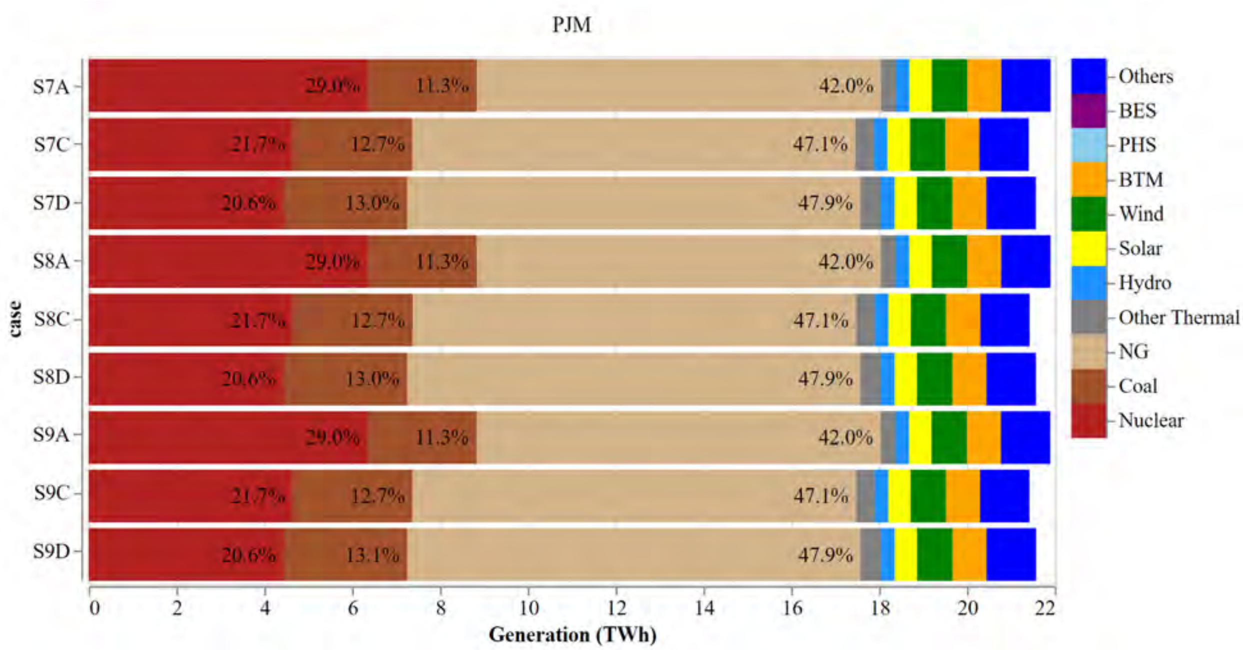


Figure 51. Generation mix for the PJM region from 2025-06-25 to 2025-07-02 in TWh. The Y-axis present the short name for all the simulations performed, S8 and S9 refer to the six heat wave cases.

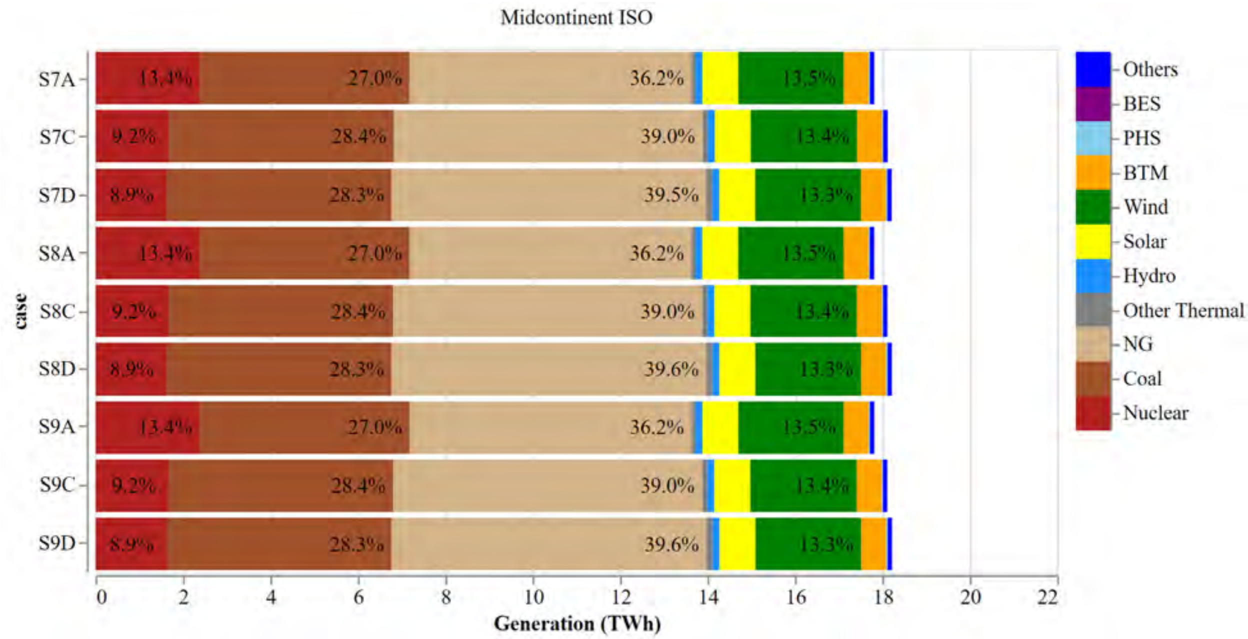


Figure 52. Generation mix for the Midcontinent ISO region from 2025-06-25 to 2025-07-02 in TWh. The Y-axis present the short name for all the simulations performed, S8 and S9 refer to the six heat wave cases.

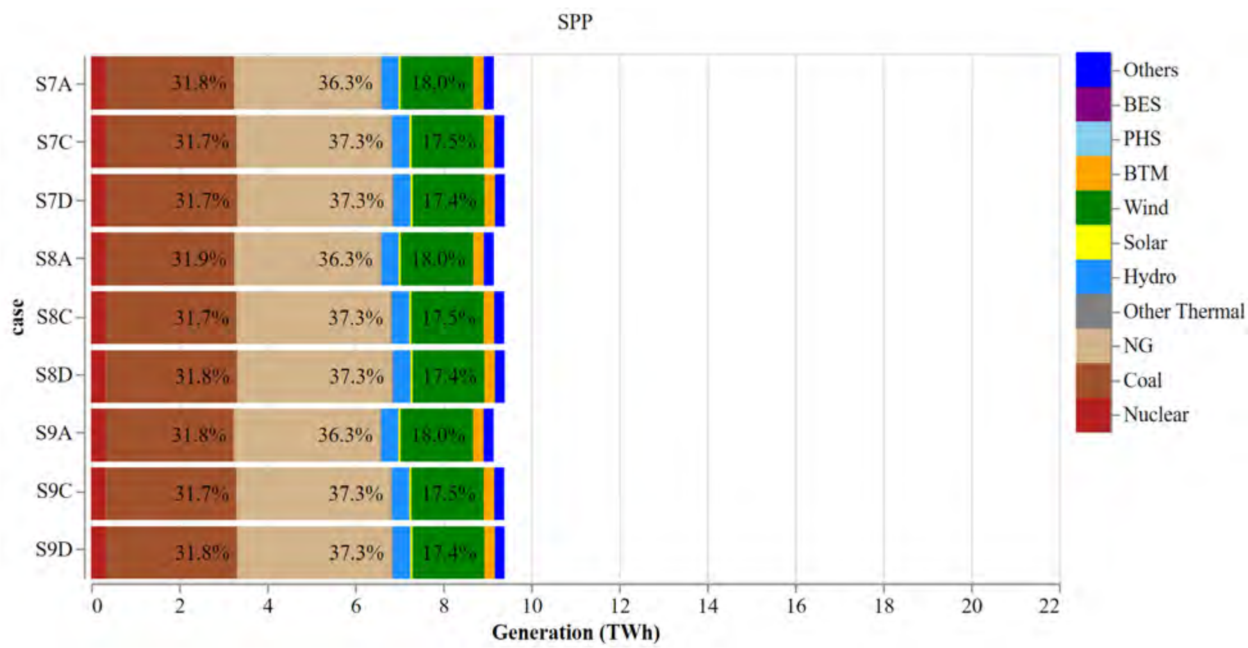


Figure 53. Generation mix for the SPP region from 2025-06-25 to 2025-07-02 in TWh. The Y-axis present the short name for all the simulations performed, S8 and S9 refer to the six heat wave cases.

4.7 Comparative Analysis

Table 29 compares the installed capacity by unit type for the WI and EI interconnections. The portions shaded in light green represent only controllable units (i.e., generation units that are not directly dependent on climate). As previously demonstrated, the unserved energy for WI is significantly larger than for EI under the scenarios and nuclear availability considered. Despite WI having a significantly larger installed capacity—nearly 70% above its peak base load compared to EI's 43%—the crucial factor is the capacity of controllable units. EI has approximately 12% installed capacity of controllable units above its peak base load, while WI has about 9% below its peak base load. Consequently, this leads to greater challenges for WI in flexibly adjusting its supply to meet reserve and energy demands.

Table 29. Install capacity by unit type assessment in between WI and EI. The assessment is performed considering the interconnections respective peak base load and the unit that are controllable (i.e., generation units that are not directly dependent on the climate).

Type	WI		EI	
	Capacity (MW)	Percentage (%)	Capacity (MW)	Percentage (%)
Coal	14,975	5.77	100,559	12.26
Nuclear	8,175	3.15	88,194	10.75
Gas	78,489	30.27	362,486	44.18
Other	37,412	14.43	93,915	11.45
Hydro	49,761	19.19	51,138	6.23
Wind	31,188	12.03	78,774	9.60
Solar	39,331	15.17	45,480	5.54
Peak load	152,850	-	575,520	-
Total	259,331	100.0	820,546	100.0
Total controllable resources	139,051	53.62	645,154	78.62
Over install	106,480	69.66	245,026	42.57
Over install controllable	(13,799)	(9.03)	69,634	12.10

4.8 Conclusion

PCM simulations shows that in the Western Interconnection, less nuclear availability and extreme weather conditions, such as heat wave and drought, would create:

- Increased shortage in reserves
- Increased unserved load during peak load summer days
- Higher generation cost compared to the BAU case as nuclear generation is replaced by high-marginal cost NG units
- Higher greenhouse gas emissions
- Changed PF on major paths in WI, indicating the nuclear availability and weather's impact on interregional energy imports/exports.

The exploration of nuclear availability conditions, heat wave and drought scenarios leads to higher LMP as generation cost increases by dispatching high marginal cost natural gas units. With increased participation of NG, the greenhouse gas emissions increase, accompanied by a slight decrease in solar and wind curtailment. The system is not able to meet reserve requirements in normal weather conditions with complete unavailability of the nuclear fleet. The unserved reserves mainly affected are *regulation up* and *flexible up* which provide different ramp characteristics to increase generation. Reserves are needed for the reliable operation of the power system. Failure to meet the reserve requirements leaves the system vulnerable to abrupt shifts in demand and unforeseen interruptions in power supply. The unserved load metric is presented, but the values likely underestimate the actual unserved load in the generated scenarios given the significant reserve deficiencies spatially during system stress periods. However, even with the likely underestimated unserved load, the extreme weather conditions such as a combined heat wave and drought can significantly stress the WI system, leading to 490,000 homes without power due to the lack of nuclear units in Scenario 6 nuclear availability Schedule B.

In the Eastern Interconnection, the reduction of nuclear availability and heat wave conditions would create:

- Increased shortage in reserves
- Slightly increased unserved load during peak load summer days in several regions
- Higher generation cost compared to the BAU case as nuclear generation is replaced by high-marginal cost thermal units and more greenhouse gas emissions
- Changed generation mix and total energy generated on major regions in EI, indicating the nuclear availability's impact on interregional energy imports/exports.

The EI is a more robust system compared with WI due to a larger installed capacity of controllable units in relation to their peak base load. The extended nuclear availability schedule C/D demonstrated to be more impactful to stress the EI than the heat wave events Scenarios 7 and 8. The EI during nuclear availability schedule D is the only type with unserved energy. The unmet reserves hours increase significantly with nuclear availability C/D.

5. KEY TAKEAWAYS

This report sets the stage for the current state of the electric grid with respect to reliability by describing the contribution of nuclear power in both capacity and synchronous spinning inertia to enhance resource adequacy and stabilize frequency during large disturbances, giving the system time to adapt. Nuclear energy provides a significant portion of both inertia and capacity in the eastern United States such that a large unplanned decrease has the potential to substantially reduce both elements that could have significant consequences. Today the amount of inertia in both the western and eastern regions is not considered a concern. However, with greater increase in variable and non-synchronous inverter-based resources this may not be the case. The information provided about inertia in the report can be used to analyze when a proportional decrease matters. Furthermore, the relative contributions of capacity and inertia provide guidance on which areas to evaluate first, specifically the areas with high amount of nuclear power and resource adequacy issues within or adjacent to the grid region. For example, PJM and SERC along with their adjacency to MISO.

Two types of methods have been developed, configured, and implemented. These models consist of a rapid analysis method, which can be readily configured with data from a given market or utility area, and a comprehensive model that considers transmission constraints using PCM models. The rapid analysis model was initially applied to PJM in the Eastern Interconnection, and the PCM models were applied to both Western and Eastern Interconnection. Although the Western Interconnection does not have a large proportional amount of nuclear power, a configuration based on expected 2030 assets and loads, with the notable exception of keeping Diablo Canyon online, offered an efficient way to demonstrate the utility of the modeling methodology. For the Eastern Interconnection, a configuration based on 2025 assets and loads demonstrated the impact of the different nuclear availability. Completing the analysis for the Western Interconnection provided practice in the methodology and yielded a surprising finding: nuclear power plays a significant role even in the western region under drought and extreme heat wave events that have occurred over that past decade and are anticipated to happen again. However, the Eastern Interconnection shows a more reliable performance under extended nuclear maintenance schedules and heat wave events due to more installed capacity of controllable units.

From the Rapid Analysis Method, we found that MISO and PJM, the two electricity markets with the highest nuclear penetration levels, demonstrate significant impacts on the economy, environment, and reliability when simulating the loss of all nuclear units. Economically, our simple analysis suggests that removing nuclear units can result in a marginal cost increase of up to 50 $/MWh. In some cases, the maximum marginal cost increases from 75 $/MWh to over 120 $/MWh, possibly resulting in severe economic consequences. Environmentally, our analysis shows that hourly system-wide CO2 emission rates would increase by 20 to 30 kt/h, resulting in significantly higher annual carbon emissions. Losing all nuclear units in PJM is catastrophic in terms of reliability because of its greater nuclear penetration levels. The LOLH increases from 0 hours to over 300 hours in PJM. The reliability impact on MISO is less severe than on PJM due to its lower nuclear penetration level; however, losing all nuclear units still led to its failure to comply with industry reliability standard. This analysis represents a highly simplified approach, yet its results provide valuable insights into the impact of nuclear unit retirements. Major caveats include the neglect of transmission network constraints and the exclusion of a small percentage of thermal units (5% in PJM and 7% in MISO),

From the PCM modeling methods, the exploration of nuclear availability conditions, heat wave, and drought scenarios leads to higher LMP as generation cost increases by dispatching high marginal cost NG units. With the increased participation of NG units, greenhouse gas emissions increase, along with a slight decrease in solar and wind curtailment. Depending on the scenario and nuclear availability schedule, the WI and EI systems cannot completely meet their demand and reserve requirements. The WI scenarios adversely affect reserve requirements for *regulation up* and *flexible up,* which provide different ramp characteristics to increase generation. The EI reserve modeling is comprised of a single requirement for *spinning reserve*. Reserves are needed for the reliable operation of the power system given that not meeting the reserves leaves the system with limited or no mitigation for abrupt shifts in demand and unforeseen interruptions in the power supply. The unserved load metric may underestimate the actual unserved load in the generated scenarios, given the significant lack of reserves spatially and limits to transmission capacity during period of system stress. The comparative analysis of the installed generation mix for the WI and EI systems considering peak base load reveals that WI has a significantly larger installed capacity compared to the EI. However, when focusing only on controllable units (i.e., generation units that are not directly dependent on climate or weather), EI shows an installed capacity that is approximately 12% above its peak base load, whereas WI has an installed capacity of around 9% below its peak base load. This supports the observation that WI struggles more to meet its demand and reserves compared to EI under the considered scenarios. The stress on the EI system is primarily related to nuclear availability schedules rather than heat wave scenarios.

Nuclear energy is shown to be a key participant in maintaining the reliability of the electricity system. Removing nuclear units from baseload power production without replacement with equally stable or dispatchable generation leaves the bulk electric system vulnerable to scenarios of drought, heatwaves, and other possible variations in supply and demand for electricity. Removing nuclear energy for the purpose of other application of heat and power will also leave the system vulnerable if mitigations to require repurposed nuclear plants to revert to electricity production are not put in place.

6. REFERENCES

[1] Nuclear Regulatory Commission (NRC), “EPA Rulemaking on the Fire Retardant DecaBDE.” In proceedings of the U.S. Nuclear Regulatory Commission Vendor Town Hall Meeting, June 21, 2023.

[2] Environmental Protection Agency (EPA), “PRE-PUBLICATION NOTICE On November 16, 2023, Michael S. Regan, the EPA Administrator, signed the following document: Decabromodiphenyl Ether and Phenol, Isopropylated Phosphate (3:1); Revision to the Regulation of Persistent, Bioaccumulative, and Toxic Ch,” Nov. 2023.

[3] NERC, “Long-Term Reliability Assessment 2023.” https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_Infographic_2023.pdf (accessed Mar. 29, 2024).

[4] EIA, “ELECTRICITY Form EIA-860 detailed data with previous form data (EIA-860A/860B),” 2022. https://www.eia.gov/electricity/data/eia860/ (accessed Mar. 29, 2024).

[5] EIA, “ELECTRICITY HOURLY ELECTRIC GRID MONITOR.” https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO (accessed Mar. 29, 2024).

[6] P. M. Anderson and A. A. Fouad, *Power System Control and Stability*. IEEE, 2002.

[7] EIA, “Form EIA-923 detailed data with previous form data (EIA-906/920),” 2023. https://www.eia.gov/electricity/data/eia923/ (accessed Dec. 01, 2023).

[8] C. L. Shay, S. Yeh, J. DeCarolis, D. H. Loughlin, C. L. Gage, and E. Wright, “EPA U.S. National MARKAL Database: Database Documentation,” Washington, DC, 2006.

[9] National Renewable Energy Laboratory, “2023 Annual Technology Baseline,” 2023. https://atb.nrel.gov/ (accessed Dec. 01, 2023).

[10] EIA, “ENVIRONMENT Carbon Dioxide Emissions Coefficients,” 2023. https://www.eia.gov/environment/emissions/co2_vol_mass.php (accessed Mar. 29, 2024).

[11] PJM Interconnection, “Generation by Fuel Type.” PJM Interconnection, [Online]. Available: https://dataminer2.pjm.com/feed/gen_by_fuel/definition.

[12] PJM Interconnection, “Hourly Load: Metered.” PJM Interconnection, [Online]. Available: https://dataminer2.pjm.com/feed/hrl_load_metered/definition.

[13] Midcontinent ISO, “MISO Market Reports.” Midcontinent ISO, [Online]. Available: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/.

[14] United States Nuclear Regulatory Commission, “Power Reactor Status Reports.” https://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/index.html (accessed Oct. 15, 2023).

[15] J. Sathaye, L. Dale, P. Larsen, and E. Al., “Estimating Risk to California Energy Infrastructure from Projected Climate Change,” *Clim. Chang.*, 2012, [Online]. Available: https://escholarship.org/uc/item/17582969.

[16] M. Auffhammer, P. Baylis, and C. H. Hausman, “Climate change is projected to have severe impacts on the frequency and intensity of peak electricity demand across the United States,” *Proc. Natl. Acad. Sci. U. S. A.*, vol. 114, no. 8, pp. 1886–1891, 2017, doi: 10.1073/pnas.1613193114.

[17] J. A. Sathaye *et al.*, “Estimating impacts of warming temperatures on California’s electricity system,” *Glob. Environ. Chang.*, vol. 23, no. 2, pp. 499–511, 2013, doi:

10.1016/j.gloenvcha.2012.12.005.

[18] M. Bartos *et al.*, “Impacts of rising air temperatures on electric transmission ampacity and peak electricity load in the United States,” *Environ. Res. Lett.*, vol. 11, no. 11, 2016, doi: 10.1088/1748-9326/11/11/114008.

[19] M. D. Bartos and M. V. Chester, “Impacts of climate change on electric power supply in the Western United States,” *Nat. Clim. Chang.*, vol. 5, no. 8, pp. 748–752, 2015, doi: 10.1038/nclimate2648.

[20] S. Sundar, M. T. Craig, A. E. Payne, D. J. Brayshaw, and F. Lehner, “Meteorological drivers of resource adequacy failures in current and high renewable Western U.S. power systems,” *Nat. Commun.*, vol. 14, no. 1, 2023, doi: 10.1038/s41467-023-41875-6.

[21] S. W. D. Turner, N. Voisin, J. Fazio, D. Hua, and M. Jourabchi, “Compound climate events transform electrical power shortfall risk in the Pacific Northwest,” *Nat. Commun.*, vol. 10, no. 1, 2019, doi: 10.1038/s41467-018-07894-4.

[22] A. P. Dobos, “PVWatts Version 5 Manual - Technical Report NREL/TP-6A20-62641,” 2014. [Online]. Available: https://www.nrel.gov/docs/fy14osti/62641.pdf.

[23] R. H. White *et al.*, “The unprecedented Pacific Northwest heatwave of June 2021,” *Nat. Commun.*, vol. 14, no. 1, 2023, doi: 10.1038/s41467-023-36289-3.

[24] J. E. Dagle *et al.*, “National Transmission Planning Study - Stress Analysis,” 2024. doi: (Unpublished report).

[25] A. D. Jones *et al.*, “Continental United States climate projections based on thermodynamic modification of historical weather,” *Sci. Data*, vol. 10, no. 1, pp. 1–21, 2023, doi: 10.1038/s41597-023-02485-5.

[26] R. H. Moss *et al.*, “The next generation of scenarios for climate change research and assessment,” *Nature*, vol. 463, no. 7282, pp. 747–756, 2010, doi: 10.1038/nature08823.

[27] C. R. McGrath *et al.*, “tell: a Python package to model future total electricity loads in the United States,” *J. Open Source Softw.*, vol. 7, no. 79, p. 4472, 2022, doi: 10.21105/joss.04472.

[28] K. A. Bumbaco and P. W. Mote, “Three recent flavors of drought in the Pacific Northwest,” *J. Appl. Meteorol. Climatol.*, vol. 49, no. 9, pp. 2058–2068, 2010, doi: 10.1175/2010JAMC2423.1.

[29] S. W. D. Turner, N. Voisin, K. Nelson, and V. Tidwell, “Drought Impacts on Hydroelectric Power Generation in the Western United States: A multiregional analysis of 21st century hydropower generation,” no. September, 2022, [Online]. Available: https://www.ntis.gov/about.

[30] S. W. D. Turner, C. Bracken, N. Voisin, and K. Oikonomou, “HydroWIRES B1: Monthly and Weekly Hydropower Constraints Based on Disaggregated EIA-923 Data.” Zenodo. Version 1.2.0, Jan. 2024, doi: 10.5281/zenodo.10574003.

[31] NERC, “Reliability Terminology,” 2013. https://www.nerc.com/AboutNERC/Documents/Terms AUG13.pdf (accessed Mar. 28, 2024).

[32] North American Electric Reliability Corporation (NERC), “BAL-002-WECC-3—Contingency Reserve,” 2021.

[33] US EPA, “Sources of Greenhouse Gas Emissions.” https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions (accessed Mar. 28, 2024).

[34] Hitachi, “GridView energy planing & traiding.” https://library.e.abb.com/public/6676a5b70f5b4e148c03b74f77056318/GridView-brochure-9AKK106930A8192.pdf?x-

sign=Su4cZgpFEFNfBltLZfDqzYrAEp7AUvJfbjtjFPZ0WJMSjOFjGPoBbGGfsLiO19XW (accessed Mar. 28, 2024).

[35] WECC, “Anchor Data Set (ADS).” https://www.wecc.org/ReliabilityModeling/Pages/AnchorDataSet.aspx (accessed Nov. 05, 2023).

[36] EIA, “NUCLEAR & URANIUM State Nuclear Profiles — Archive.” https://www.eia.gov/nuclear/state/#_ftn1 (accessed Mar. 28, 2024).

[37] K. Riener D. and P. Mayeda, “Economic Benefits of Diablo Canyon Power Plant An Economic Impact Study June 2013,” no. June, p. 72, 2013, [Online]. Available: http://large.stanford.edu/courses/2016/ph241/orozco2/docs/mayeda.pdf.

[38] G. McCullough, Robert and Vatter, Marc and Anderson, Rose and Heimensen, Jil and Long, Sean and May, Christopher and Nisbet, Andrew and Oursland, *Economic Analysis of the Columbia Generating Station December 2013*. McCullough Research, 2013.

[39] WECC, “WECC Overview of System Operations.” https://www.wecc.org/Administrative/06-Balancing Authority Overview.pdf (accessed Mar. 28, 2024).

[40] Eastern Interconnection Reliability Assessment Group (ERAG), “Multiregional Modeling Working Group (MMWG) Procedural Manual,” 2023. [Online]. Available: https://www.rfirst.org/wp-content/uploads/2023/07/MMWG_Procedural_Manual_v35.pdf.

[41] EIA, “Use of energy explained Energy use in homes.” https://www.eia.gov/energyexplained/use-of-energy/electricity-use-in-homes.php (accessed Mar. 27, 2024).